BLACK HILLS CORP /SD/
Form 10-K
February 29, 2012

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, 2011

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

For the transition period from ___________________ to __________________

Commission File Number 001-31303

BLACK HILLS CORPORATION

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

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

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

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

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. 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, 2011	$1,169,775,169

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, 2012	
Common stock, $1.00 par value	43,929,272	shares

Documents Incorporated by Reference
Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2012 Annual Meeting of Stockholders to be held on May 23, 2012, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income
Aquila	Aquila, Inc.
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila
ARO	Asset Retirement Obligations
Basin Electric	Basin Electric Power Cooperative
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
BHC	Black Hills Corporation; the Company
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 Energy	The name used to conduct the business of Black Hills Utility Holdings, Inc., and its subsidiaries
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
BLM	United States Bureau of Land Management
Btu	British thermal unit
CFTC	United States Commodity Futures Trading Commission
CG&A	Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation
Cheyenne Light Pension Plan	The Cheyenne Light, Fuel and Power Company Pension Plan

City of Gillette	The City of Gillette, Wyoming, affiliate of the JPB. The JPB financed the purchase of 23% of Wygen III power plant for the City of Gillette
CO_2	Carbon dioxide
Colorado Electric	Black Hills Colorado Electric Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado Gas	Black Hills Colorado Gas Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Cooling Degree Day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average.
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
CT	Combustion turbine
DC	Direct current
De-designated interest rate swaps	The $250 million notional amount interest rate swaps that were originally designated as cash flow hedges under the accounting for derivatives and hedges but subsequently de-designated in December 2008
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
Dth	Dekatherms
EBITDA	Earnings before interest, taxes, depreciation and amortization, a Non-GAAP measurement
ECA	Energy Cost Adjustment
Enserco	Enserco Energy Inc., a wholly-owned subsidiary of Black Hills Non-regulated Holdings, which is presented in discontinued operations throughout this Annual Report filed on Form 10-K
EPA	United States Environmental Protection Agency
EPA Region VIII	EPA Region VIII (Mountains and Plains) located in Denver, Colorado serving Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming and 27 Tribal Nations
Equity Forward Agreement	Equity Forward Agreement with J. P. Morgan connected to a public offering of 4,413,519 million shares of Black Hills Corporation common stock, including the over-allotment shares
ERISA	Employee Retirement Income Security Act
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
FTC	Federal Trade Commission
GAAP	Accounting principles generally accepted in the United States of America
GCA	Gas Cost Adjustment
GE	General Electric Company
GHG	Greenhouse gases
Global Settlement	

	Settlement with a utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders
Happy Jack	Happy Jack Wind Farm, LLC, owned by Duke Energy Generation Services
Hastings	Hastings Fund Management Ltd

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Heating Degree Day	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average.
IGCC	Integrated Gasification Combined Cycle
IIF	IIF BH Investment LLC, a subsidiary of an investment entity advised by J.P. Morgan Asset Management
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
IPP	Independent power producer
IPP Transaction	The July 11, 2008 sale of seven of our IPP plants to affiliates of Hastings and IIF
IRS	United States Internal Revenue Service
IUB	Iowa Utilities Board
J.P. Morgan	J.P. Morgan Securities LLC
JPB	Consolidated Wyoming Municipalities Electric Power System Joint Powers Board. The JPB exists for the purpose of, among other things, financing the electrical system of the City of Gillette.
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
KCC	Kansas Corporation Commission
kV	Kilovolt
KW	Kilowatt
KWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
MACT	Maximum Achievable Control Technology
MAPP	Mid-Continent Area Power Pool
MATS	Utility Mercury and Air Toxics Rules under the United States EPA National Emissions Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units
Mbbl	Thousand barrels of oil
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent
MDU	Montana Dakota Utilities Co., a regulated utility division of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
Moody's	Moody's Investors Service, Inc.
MSHA	Mine Safety and Health Administration
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hours
Native load	Energy required to serve customers within our service territory
Nebraska Gas	

	Black Hills Nebraska Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
NERC	North American Electric Reliability Corporation
NGL	Natural Gas Liquids
NO_x	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 initially adopted in 1999
NYMEX	New York Mercantile Exchange
OCA	Office of Consumer Advocate
OPEC	Organization of the Petroleum Exporting Countries
OSHA	Occupational Safety & Health Administration
PCA	Power Cost Adjustment
Peak demand	Peak demand represents the highest point of customer usage for a single hour
PGA	Purchased Gas Adjustment
PPA	Power Purchase Agreement
PPACA	Patient Protection and Affordable Care Act of 2010
PSCo	Public Service Company of Colorado
PUD	Proved undeveloped reserves
PUHCA 2005	Public Utility Holding Company Act of 2005
PURPA	Public Utility Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act
Revolving Credit Facility	Our $500 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, originally expiring April 14, 2013. We entered into a new facility in February 2012 which expires in 2017.
S&S	Significant and Substantial as defined by Mine Safety Act
SCADA	Supervisory Control and Data Acquisition
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
Silver Sage	Silver Sage Windpower, LLC, owned by Duke Energy Generation Services
SO_2	Sulfur dioxide
S&P	Standard & Poor's, a division of The McGraw-Hill Companies, Inc.
TCA	Transmission Cost Adjustment
Twin Eagle	Twin Eagle Resource Management, LLC
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
WDEQ	Wyoming Department of Environmental Quality
WECC	Western Electricity Coordinating Council
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

ACCOUNTING PRONOUNCEMENTS

ASC	Accounting Standards Codification
ASC 220	ASC 220, "Comprehensive Income"
ASC 820	ASC 820, "Fair Value Measurements and Disclosures"
ASC 932-10-S99	ASC 932-10-S99, "Extractive Activities - Oil and Gas, SEC Materials"
ASU	Accounting Standards Update
ASU 2011-04	ASU 2011-04, "Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS"
ASU 2011-05	ASU 2011-05, "Comprehensive Income: Presentation of Comprehensive Income"
ASU 2011-08	ASU 2011-08, "Intangibles - Goodwill and Other: Testing Goodwill for Impairment"
ASU 2011-12	ASU 2011-12, "Comprehensive Income: Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05"
IFRS	International Financial Reporting Standards

Website Access to Reports

The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officers, Corporate Governance Guidelines of the Board of Directors and Policy for Director Independence. The information contained on our website is not part of this document.

Forward-Looking Information

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

- Macro- and micro-economic changes in the economy and energy industry, including the impact of (i) consolidations and changes in competition, and (ii) general economic and political conditions, including tax rates or policies and inflation rates;

- The timing, volatility and extent of changes in energy and commodity prices, supply or volume, the cost and availability of transportation of commodities, changes in interest rates, and the demand for our services, any of which can affect our earnings, our financial liquidity and the underlying value of our assets;

- Our ability to comply, or to make expenditures required to comply, with changes in laws and regulations, particularly those relating to energy markets, taxation, safety and protection of the environment, and our ability to recover those expenditures in customer rates, where applicable;

- Federal and state laws concerning climate change and air emissions, including emission reduction mandates, carbon emissions and renewable energy portfolio standards, which may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain, or which could require closure of one or more of our generating units;

- Changes in business, regulatory compliance and financial reporting practices and subsequent rules and regulations;

- The effect of Dodd-Frank and the regulations to be adopted thereunder on our use of derivative instruments in connection with our activities to hedge our expected production of crude oil and natural gas and on our use of interest rate derivative instruments;

- Changes in state laws or regulations that could cause us to curtail our business activities;

- Our ability to successfully integrate and profitably operate any future acquisitions;

- Our ability to successfully complete the sale of Enserco Energy Inc. to Twin Eagle Resource Management, LLC for net cash proceeds of approximately $160 million to $170 million, subject to working capital and other closing adjustments;

- Our ability to obtain adequate cost recovery for our utility operations through regulatory proceedings and receive favorable rulings in periodic applications to recover costs for fuel, transportation, transmission and purchased power in our regulated utilities;

- Our ability to receive regulatory approval to recover in rate base our expenditures for new power generation facilities or other utility infrastructure;

- Our ability to recover our borrowing costs, including debt service costs, in our customer rates;

- The extent of our success in connecting natural gas supplies to gathering, processing and pipeline systems;

- Our ability to minimize losses related to defaults on amounts due from customers and counterparties, including counterparties to trading and other commercial transactions;

- The timing and extent of scheduled and unscheduled outages of power generation facilities;

- Our ability to complete the permitting, construction, start-up and operation of power generating facilities in a cost-effective and timely manner;

- Our ability to accurately estimate demand from our customers for natural gas;

- Weather and other natural phenomena;

- Our ability to meet forecasted production volumes for our oil and gas properties, which may be dependent upon issuance by federal, state and tribal governments, or agencies thereof, of drilling, environmental and other permits, and the availability of specialized contractors, work force and equipment, or the possibility of reductions in our drilling program resulting from the current economic climate and commodity prices, which also may prevent us from maintaining production rates and replacing reserves for our oil and gas properties;

- The amount of collateral required to be posted from time to time in our transactions;

- Our ability to effectively use derivative financial instruments to hedge commodity and interest rate risks;

- Our ability to provide accurate estimates of proved oil and gas reserves, coal reserves and future production rates and associated costs;

- Price risk due to marketable securities held as investments in employee benefit plans;

- Our ability to successfully maintain our corporate credit rating;

- The impact of the pending sale of Enserco Energy Inc., our non-regulated energy marketing business, on reducing our risk profile, improving our credit metrics and enhancing our ability to produce more stable cash flows and earnings;

- Our ability to access revolving credit capacity and comply with loan covenants;

- Capital market conditions and market uncertainties related to interest rates, which may affect our ability to raise capital on favorable terms;

- The amount and timing of capital deployment in new investment opportunities or for the repurchase of debt or stock;

- Our ability to continue paying our regular quarterly dividend;

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Our ability to obtain permanent financing for capital expenditures on reasonable terms either through long-term debt or issuance of equity;

- The effect of accounting policies issued periodically by accounting standard-setting bodies;

- The accounting treatment and earnings impact associated with interest rate swaps;

- The possibility that we may be required to take impairment charges to reduce the carrying value of some of our long-lived assets when indicators of impairment emerge;

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- The possibility that we may be required to take impairment charges under the SEC's full cost ceiling test for the accumulated costs of our natural gas and oil reserves;
- The outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements on our financial condition or results of operations;
- Additional liabilities for environmental conditions, including remediation and reclamation obligations, under environmental laws;
- Our ability to successfully complete labor negotiations with labor unions with which we have collective bargaining agreements and for which we are currently in, or are soon to be in, contract renewal negotiations; and
- The cost and effect on our business, including insurance, resulting from terrorist actions and cyber-attacks or responses to such actions or events.

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

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

History and Organization

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

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

For more than 15 years, we have also owned and operated an energy marketing business, Enserco, which engages in natural gas, crude oil, coal, power and environmental marketing and trading in the United States and Canada. In the fourth quarter of 2011, we made the decision to sell Enserco, which constitutes our entire non-regulated Energy Marketing segment. On January 18, 2012, we entered into a definitive agreement to sell all of the outstanding stock of Enserco, which resulted in the Energy Marketing segment being reported as discontinued operations. This transaction is expected to close in the first quarter of 2012. For comparative purposes, all prior periods presented have been restated to reflect the reclassification of this segment to discontinued operations on a consistent basis. See Note 23 in the accompanying Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further details.

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

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 201,500 electric customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light, a combination electric and gas utility, and its approximately 34,800 gas utility customers in Wyoming. Our Gas Utilities segment serves approximately 528,800 natural gas utility customers in Colorado, Nebraska, Iowa and Kansas. Our Electric Utilities own 865 MWs of generation and 8,496 miles of electric transmission and distribution lines, and our Gas Utilities own 624 miles of intrastate gas transmission pipelines and 19,747 miles of gas distribution mains and service lines. Our Electric and Gas Utilities generated net income of $81.9 million for the year ended December 31, 2011 and had total assets of $3.0 billion at December 31, 2011.

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 Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy primarily to other utilities under long-term contracts. Our Coal Mining segment produces coal at our coal mine near Gillette, Wyoming. Our Non-regulated Energy Group generated net income of $0.9 million for the year ended December 31, 2011 and had total assets of $0.6 billion at December 31, 2011.

Segment Financial Information

We discuss our business strategy and other prospective information in Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations. Financial information regarding our business segments is incorporated herein by reference to Item 8 - Financial Statements and Supplementary Data, and particularly Note 17 to the Consolidated Financial Statements, in this Annual Report on Form 10-K.

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

Business Group Overview

Utilities Group

We conduct electric utility operations and combination electric and gas utility operations through three subsidiaries: Black Hills Power (South Dakota, Wyoming and Montana), Cheyenne Light (Wyoming), and Colorado Electric (Colorado). Our Electric Utilities generate, transmit and distribute electricity to approximately 201,500 customers in South Dakota, Wyoming, Colorado and Montana. Additionally, Cheyenne Light distributes natural gas to approximately 34,800 natural gas utility customers in Wyoming. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates.

We conduct natural gas utility operations on a state-by-state basis through our Colorado Gas, Nebraska Gas, Iowa Gas and Kansas Gas subsidiaries. Our Gas Utilities distribute and transport natural gas through our distribution network to approximately 528,800 customers in Colorado, Nebraska, Iowa and Kansas. Additionally, we sell temporarily-available, contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates.

In addition to our regulated operations, we also provide non-regulated services through our Service Guard and Tech Services product lines. Service Guard primarily provides appliance repair services to approximately 63,000 residential customers through company technicians and third party service providers in Colorado, Iowa, Kansas and Nebraska most typically through on-going monthly service agreements. Tech Services primarily serves gas transportation customers throughout our service territory by constructing customer-owned gas infrastructure facilities, typically through one-time contracts, with a limited number of on-going monthly maintenance agreements.

Electric Utilities Segment

Capacity and Demand

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

	System Peak Demand (in MW)					
	2011		2010		2009	
	Summer	Winter	Summer	Winter	Summer	Winter
Black Hills Power	452	408	396	377	387	392
Cheyenne Light	181	175	176	164	169	171
Colorado Electric	392	297	384	289	365	296
Total Electric Utilities Peak Demands	1,025	880	956	830	921	859

Regulated Power Plants

As of December 31, 2011, our Electric Utilities' ownership interests in electric generation plants were as follows:

Unit	Fuel Type	Location	Ownership Interest %	Owned/Leased Capacity (MW)	Year Installed
Black Hills Power:					
Wygen III [(1)]	Coal	Gillette, WY	52.0%	57.2	2010
Neil Simpson II	Coal	Gillette, WY	100.0%	90.0	1995
Wyodak [(2)]	Coal	Gillette, WY	20.0%	72.4	1978
Osage [(3)]	Coal	Osage, WY	100.0%	34.5	1948-1952
Ben French	Coal	Rapid City, SD	100.0%	25.0	1960
Neil Simpson I	Coal	Gillette, WY	100.0%	21.8	1969
Neil Simpson CT	Gas	Gillette, WY	100.0%	40.0	2000
Lange CT	Gas	Rapid City, SD	100.0%	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, SD	100.0%	10.0	1965
Ben French CTs #1-4 [(4)]	Gas/Oil	Rapid City, SD	100.0%	100.0	1977-1979
Cheyenne Light:					
Wygen II	Coal	Gillette, WY	100.0%	95.0	2008
Colorado Electric:					
Pueblo Airport Generation	Gas	Pueblo, CO	100.0%	180.0	2011
Capital Lease - Colorado IPP [(5)]	Gas	Pueblo, CO	—%	200.0	2011
W.N. Clark #1-2 [(6)]	Coal	Canon City, CO	100.0%	40.0	1955, 1959
Pueblo #6	Gas	Pueblo, CO	100.0%	20.0	1949
Pueblo #5	Gas	Pueblo, CO	100.0%	9.0	1941, 2001
AIP Diesel	Oil	Pueblo, CO	100.0%	10.0	2001
Diesel #1-5	Oil	Pueblo, CO	100.0%	10.0	1964
Diesel #1-5	Oil	Rocky Ford, CO	100.0%	10.0	1964
Total MW Owned Capacity				1,064.9	

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

(2) Wyodak, a 362 MW mine-mouth coal-fired power plant, is owned 80% by PacifiCorp and 20% by Black Hills Power. This baseload plant is operated by PacifiCorp and our WRDC coal mine furnishes all of the fuel supply for the plant.

(3) Operations at the Osage plant were suspended October 1, 2010 due to the availability of more economical generation alternatives.

(4) Upon expiration of the contract with PacifiCorp in June 2012 (see below), the capacity of these units will be decreased to 80 MW.

(5) Colorado Electric entered into a 20-year PPA with Black Hills Colorado IPP for 200 MW of power from their gas-fired plants. This PPA, accounted for as a capital lease, was effective on January 1, 2012 upon completion of construction of the plants.

(6) In December 2010, Colorado Electric received a final order from the CPUC that approved the retirement of its W.N. Clark coal-fired generation facility by December 31, 2013.

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

Fuel Source	2011	2010	2009
Coal	$15.89	$12.77	$13.99
Gas and Oil	$150.00	$131.28	$85.52
Total Average Fuel Cost	$16.77	$13.57	$15.22
Purchased Power - Coal, Gas and Oil	$28.80	$29.57	$28.44
Purchased Power - Renewable Sources	$46.71	$45.76	$43.66

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

Power Supply	2011	2010	2009
Coal-fired	38 %	42 %	39 %
Gas and Oil	—	—	1
Total Generated	38	42	40
Purchased	62	58	60
Total	100 %	100 %	100 %

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

- Black Hills Power's PPA with PacifiCorp expiring in 2023, which provides for the purchase of 50 MW of coal-fired baseload power;
- Black Hills Power's reserve capacity integration agreement with PacifiCorp expiring in June 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 Black Hills Colorado IPP expiring in 2031, which provides 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines;
- Colorado Electric's PPA with PSCo expiring at December 31, 2012, whereby Colorado Electric purchases 50 MW of economy energy;
- Colorado Electric's PPA with Cargill expiring at December 31, 2013, whereby Colorado Electric purchases 50 MW of economy energy;
- Cheyenne Light's PPA with Black Hills Wyoming expiring in August 2014, whereby Black Hills Wyoming provides 40 MW of energy and capacity from its Gillette CT;
- Cheyenne Light's PPA with Black Hills Wyoming expiring December 31, 2022, whereby Black Hills Wyoming provides 60 MW of unit-contingent capacity and energy from its Wygen I facility. The PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility between 2013 and 2019. The purchase price related to the option is $2.55 million per MW. This option price is reduced annually by an amount of annual depreciation assuming a facility life of 35 years;

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

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

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

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

- MDU owns a 25% ownership interest in Wygen III's net generating capacity for the life of the plant. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, Black Hills Power will provide MDU with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU;

- The City of Gillette owns a 23% ownership interest in Wygen III's net generating capacity for the life of the plant. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, Black Hills Power will provide the City of Gillette with its first 23 MW from our other generation facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, Black Hills Power will also provide the City of Gillette their operating component of spinning reserves;

- Black Hills Power's agreement to supply up to 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 decreasing capacity purchase over the term of the agreement. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

2012-2017	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;

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

- Cheyenne Light's agreement with Basin Electric, whereby Cheyenne Light will supply 40 MW of capacity and energy through March 31, 2013 and a separate agreement whereby Cheyenne Light will receive 40 MW of capacity and energy from Basin Electric through March 31, 2013.

Transmission and Distribution. Through our Electric Utilities, we own electric transmission systems composed of high voltage transmission lines (greater than 69 kV) and low voltage lines (69 or fewer kV). We also jointly own high voltage lines with Basin Electric and Powder River Energy Corporation.

At December 31, 2011, our 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	618	2,999
Black Hills Power - Jointly Owned [1]	SD, WY	47	—
Cheyenne Light	SD, WY	25	1,235
Colorado Electric	CO	243	3,329

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

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

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

In order to serve Cheyenne Light's existing load, Cheyenne Light has a network transmission agreement with Loveland Area Project.

Shared Services Agreement. Black Hills Power, Cheyenne Light, and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity charges for the use of assets by the affiliate entity. Black Hills Colorado IPP and Colorado Electric are also parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric assets.

Operating Statistics

The following tables summarize sales revenue, quantities and customers for our Electric Utilities:

Revenue - Electric (in thousands)	2011	2010	2009
Residential:			
Black Hills Power	$59,826	$53,549	$48,586
Cheyenne Light	31,287	29,506	29,198
Colorado Electric	84,646	76,596	66,548
Total Residential	175,759	159,651	144,332
Commercial:			
Black Hills Power	72,889	65,997	59,897
Cheyenne Light	55,331	52,765	51,280
Colorado Electric	73,355	66,490	56,002
Total Commercial	201,575	185,252	167,179
Industrial:			
Black Hills Power	25,723	22,621	20,014
Cheyenne Light	11,629	10,542	11,121
Colorado Electric	33,332	28,812	31,067
Total Industrial	70,684	61,975	62,202
Municipal:			
Black Hills Power	3,172	3,029	2,735
Cheyenne Light	1,765	1,293	932
Colorado Electric	12,912	10,443	4,408
Total Municipal	17,849	14,765	8,075
Subtotal Retail Revenue - Electric	465,867	421,643	381,788
Contract Wholesale:			
Black Hills Power	18,105	22,996	25,358
Off-system Wholesale:			
Black Hills Power	34,889	36,354	32,212
Cheyenne Light	9,371	9,750	8,565
Colorado Electric *	13,018	10,859	14,008
Total Off-system Wholesale	57,278	56,963	54,785
Other Revenue:			
Black Hills Power	31,027	25,217	18,277
Cheyenne Light	2,449	3,230	718
Colorado Electric	2,787	2,374	4,226
Total Other Revenue	36,263	30,821	23,221
Total Revenue - Electric	$577,513	$532,423	$485,152

*

Off-system sales revenue had been deferred by Colorado Electric from August 2010 until December 2011, when the CPUC approved a sharing mechanism as part of the rate case settlement allowing Colorado Electric a 25% share of off-system sales operating income. Revenue in 2011 represents off-system sales from August 2010 through December 2011.

Quantities Generated and Purchased (MWh)	2011	2010	2009
Generated -			
Coal-fired:			
Black Hills Power	1,717,008	1,987,037	1,721,074
Cheyenne Light	674,518	734,241	766,943
Colorado Electric	268,317	257,896	252,603
Total Coal	2,659,843	2,979,174	2,740,620
Gas and Oil-fired:			
Black Hills Power	15,221	19,269	46,723
Cheyenne Light	—	—	—
Colorado Electric	2,342	930	2,705
Total Gas and Oil	17,563	20,199	49,428
Total Generated:			
Black Hills Power	1,732,229	2,006,306	1,767,797
Cheyenne Light	674,518	734,241	766,943
Colorado Electric	270,659	258,826	255,308
Total Generated	2,677,406	2,999,373	2,790,048
Purchased -			
Black Hills Power	1,720,640	1,440,579	1,686,455
Cheyenne Light	745,983	696,756	651,201
Colorado Electric	1,948,321	1,969,896	1,991,058
Total Purchased [(a)]	4,414,944	4,107,231	4,328,714
Total Generated and Purchased	7,092,350	7,106,604	7,118,762

(a) Includes 189,255 MWh, 167,520 MWh, and 105,830 MWh in 2011, 2010 and 2009, respectively of wind power purchased.

Quantities (MWh)	2011	2010	2009
Residential:			
Black Hills Power	550,935	547,193	529,825
Cheyenne Light	264,492	261,607	255,134
Colorado Electric	629,752	628,553	589,526
Total Residential	1,445,179	1,437,353	1,374,485
Commercial:			
Black Hills Power	720,978	720,119	723,360
Cheyenne Light	601,162	603,323	583,986
Colorado Electric	720,060	726,005	666,563
Total Commercial	2,042,200	2,049,447	1,973,909
Industrial:			
Black Hills Power	408,337	382,562	353,041
Cheyenne Light	172,840	161,082	174,792
Colorado Electric	351,862	347,673	452,584
Total Industrial	933,039	891,317	980,417
Municipal:			
Black Hills Power	34,235	33,908	33,948
Cheyenne Light	9,827	6,477	3,456
Colorado Electric	126,320	113,689	37,244
Total Municipal	170,382	154,074	74,648
Subtotal Retail Quantities Sold	4,590,800	4,532,191	4,403,459
Contract Wholesale:			
Black Hills Power	349,520	468,782	645,297
Off-system Wholesale:			
Black Hills Power	1,226,548	1,163,058	1,009,574
Cheyenne Light	278,528	311,524	309,122
Colorado Electric	282,929	274,942	373,495
Total Off-system Wholesale	1,788,005	1,749,524	1,692,191
Total Quantity Sold:			
Black Hills Power	3,290,553	3,315,622	3,295,045
Cheyenne Light	1,326,849	1,344,013	1,326,490
Colorado Electric	2,110,923	2,090,862	2,119,412
Total Quantity Sold	6,728,325	6,750,497	6,740,947
Losses and Company Use:			
Black Hills Power	162,316	131,263	159,207
Cheyenne Light	93,652	86,984	91,654
Colorado Electric	108,057	137,860	126,954
Total Losses and Company Use	364,025	356,107	377,815

Total Energy	7,092,350	7,106,604	7,118,762

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Customers at End of Year	2011	2010	2009
Residential:			
Black Hills Power	54,955	54,811	54,470
Cheyenne Light	35,159	34,913	35,943
Colorado Electric	81,811	81,902	81,622
Total Residential	171,925	171,626	172,035
Commercial:			
Black Hills Power	12,864	12,779	12,261
Cheyenne Light	4,277	4,132	4,932
Colorado Electric	11,206	11,185	11,101
Total Commercial	28,347	28,096	28,294
Industrial:			
Black Hills Power	45	40	38
Cheyenne Light	2	2	2
Colorado Electric	68	63	90
Total Industrial	115	105	130
Other Electric Customers:			
Black Hills Power	311	309	143
Cheyenne Light	243	254	13
Colorado Electric	506	510	499
Total Other Electric Customers	1,060	1,073	655
Subtotal Retail Customers	201,447	200,900	201,114
Contract Wholesale:			
Black Hills Power	3	3	3
Total Customers:			
Black Hills Power	68,178	67,942	66,915
Cheyenne Light	39,681	39,301	40,890
Colorado Electric	93,591	93,660	93,312
Total Customers at Year-End	201,450	200,903	201,117

Degree Days	2011		2010		2009	
	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Heating Degree Days:						
Black Hills Power	7,579	5%	7,272	1%	7,753	8%
Cheyenne Light	7,321	(1)%	7,033	(5)%	7,411	—%
Colorado Electric	5,749	3%	5,518	(1)%	5,546	(1)%
Cooling Degree Days:						
Black Hills Power	700	17%	532	(11)%	354	(41)%
Cheyenne Light	431	58%	345	26%	203	(26)%
Colorado Electric	1,259	37%	1,074	16%	804	(13)%

Cheyenne Light Natural Gas Distribution

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

	2011	2010	2009
Revenue - Gas (in thousands):			
Residential	$22,044	$22,562	$21,495
Commercial	10,264	10,801	9,821
Industrial	3,597	3,425	3,537
Other Sales Revenue	913	803	760
Total Revenue - Gas	$36,818	$37,591	$35,613
Gross Margin (in thousands):			
Residential	$10,426	$10,004	$10,219
Commercial	3,345	3,376	3,266
Industrial	504	427	509
Other Gross Margin	545	720	760
Total Gross Margin	$14,820	$14,527	$14,754
Volumes Sold (Dth):			
Residential	2,585,056	2,636,839	2,516,699
Commercial	1,538,616	1,572,638	1,502,002
Industrial	689,935	667,062	722,776
Total Volumes Sold	4,813,607	4,876,539	4,741,477
Customers at Year-End	34,807	34,461	33,942

Gas Utilities Segment

At December 31, 2011, our Gas Utilities owned the gas transmission and distribution lines by state shown below (in line miles):

	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Colorado	124	2,987	886
Nebraska	44	3,432	3,481
Iowa	170	2,762	2,321
Kansas	286	2,582	1,296
Total	624	11,763	7,984

Operating Statistics

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

Revenue (in thousands)	2011	2010	2009
Residential:			
Colorado	$58,102	$55,211	$62,732
Nebraska	125,493	120,365	127,120
Iowa	106,292	105,255	113,781
Kansas	65,185	69,859	70,848
Total Residential	355,072	350,690	374,481
Commercial:			
Colorado	12,172	11,880	13,357
Nebraska	40,659	40,720	43,472
Iowa	46,179	46,762	54,587
Kansas	20,362	21,953	22,629
Total Commercial	119,372	121,315	134,045
Industrial:			
Colorado	2,063	1,409	1,348
Nebraska	860	3,126	3,425
Iowa	2,521	2,243	2,191
Kansas	19,571	14,312	11,057
Total Industrial	25,015	21,090	18,021
Other Sales Revenue:			
Colorado	96	97	100
Nebraska	1,971	1,960	2,077
Iowa	550	836	1,073
Kansas	3,031	3,451	3,213
Total Other Sales Revenue	5,648	6,344	6,463
Total Distribution:			
Colorado	72,433	68,597	77,537
Nebraska	168,983	166,171	176,094
Iowa	155,542	155,096	171,632
Kansas	108,149	109,575	107,747
Total Distribution	505,107	499,439	533,010
Transportation:			
Colorado	846	784	732
Nebraska	11,175	11,289	10,569
Iowa	3,935	3,708	3,876
Kansas	5,909	5,471	5,389
Total Transportation	21,865	21,252	20,566
Total Regulated:			
Colorado	73,279	69,381	78,269

Nebraska	180,158	177,460	186,663
Iowa	159,477	158,804	175,508
Kansas	114,058	115,046	113,136
Total Regulated Revenue	526,972	520,691	553,576
Non-regulated Services	27,612	30,016	26,736
Total Revenue	$554,584	$550,707	$580,312

Gross Margin (in thousands)	2011	2010	2009
Residential:			
Colorado	$17,711	$18,153	$17,443
Nebraska	51,640	49,074	44,638
Iowa	47,491	44,269	42,734
Kansas	29,701	29,591	28,999
Total Residential	146,543	141,087	133,814
Commercial:			
Colorado	2,960	3,215	3,176
Nebraska	11,643	11,965	11,785
Iowa	11,702	11,616	12,749
Kansas	6,603	6,544	6,484
Total Commercial	32,908	33,340	34,194
Industrial:			
Colorado	450	360	375
Nebraska	217	379	431
Iowa	288	235	244
Kansas	2,373	1,878	1,766
Total Industrial	3,328	2,852	2,816
Other Sales Margins:			
Colorado	96	97	101
Nebraska	1,971	1,960	2,077
Iowa	549	836	1,073
Kansas	2,455	2,722	2,312
Total Other Sales Margins	5,071	5,615	5,563
Total Distribution:			
Colorado	21,217	21,825	21,095
Nebraska	65,471	63,378	58,931
Iowa	60,030	56,956	56,800
Kansas	41,132	40,735	39,561
Total Distribution	187,850	182,894	176,387
Transportation:			
Colorado	846	784	732
Nebraska	11,175	11,289	10,569
Iowa	3,935	3,708	3,876
Kansas	5,909	5,470	5,389
Total Transportation	21,865	21,251	20,566
Total Regulated:			
Colorado	22,063	22,609	21,827
Nebraska	76,646	74,667	69,500
Iowa	63,965	60,664	60,676

Kansas	47,041	46,205	44,950
Total Regulated Gross Margin	209,715	204,145	196,953
Non-regulated Services	12,908	12,845	11,643
Total Gross Margin	$222,623	$216,990	$208,596

Volumes (in Dth)	2011	2010	2009
Residential:			
Colorado	6,437,860	6,284,559	6,355,275
Nebraska	12,076,979	12,210,574	12,619,682
Iowa	10,490,129	10,556,045	10,976,268
Kansas	6,853,163	6,926,928	6,878,243
Total Residential	35,858,131	35,978,106	36,829,468
Commercial:			
Colorado	1,472,747	1,473,924	1,444,360
Nebraska	4,833,604	5,009,105	5,189,630
Iowa	6,192,167	6,061,954	6,597,035
Kansas	2,676,439	2,673,805	2,696,870
Total Commercial	15,174,957	15,218,788	15,927,895
Industrial:			
Colorado	344,576	259,985	263,134
Nebraska	120,779	544,457	581,892
Iowa	409,723	354,435	333,324
Kansas	3,743,735	2,718,767	2,524,126
Total Industrial	4,618,813	3,877,644	3,702,476
Other Volumes:			
Colorado	—	—	—
Nebraska	—	1,341	1,400
Iowa	—	69,306	68,290
Kansas	112,253	120,445	141,909
Total Other Volumes	112,253	191,092	211,599
Total Distribution:			
Colorado	8,255,183	8,018,468	8,062,769
Nebraska	17,031,362	17,765,477	18,392,604
Iowa	17,092,019	17,041,740	17,974,917
Kansas	13,385,590	12,439,945	12,241,148
Total Distribution	55,764,154	55,265,630	56,671,438
Transportation:			
Colorado	869,570	808,859	807,999
Nebraska	24,972,560	27,327,173	25,311,501
Iowa	18,358,692	17,422,525	14,915,602
Kansas	15,015,310	14,320,893	14,069,182
Total Transportation	59,216,132	59,879,450	55,104,284
Total Volumes:			
Colorado	9,124,753	8,827,327	8,870,768
Nebraska	42,003,922	45,092,650	43,704,105

Iowa	35,450,711	34,464,265	32,890,519
Kansas	28,400,900	26,760,838	26,310,330
Total Volumes	114,980,286	115,145,080	111,775,722

Degree Days

	2011		2010		2009	
	Actual	Variance From 30-Year Average	Actual	Variance From 30-Year Average	Actual	Variance From 30-Year Average
Heating Degree Days [(a)]:						
Colorado	5,991	(7)%	5,803	(9)%	6,299	2%
Nebraska	6,190	(4)%	6,222	(5)%	6,238	5%
Iowa	7,013	(1)%	6,934	(1)%	7,279	6%
Kansas [(b)]	4,954	(1)%	4,918	—%	4,989	—%
Combined	6,143	(3)%	6,101	(3)%	6,285	(11)%

(a) The combined heating degree days are calculated based on a weighted average of total customers by state.

(b) In Kansas where we have a weather normalization mechanism, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

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

Customers	2011	2010	2009
Residential:			
Colorado	67,496	66,766	65,586
Nebraska	176,386	176,244	179,873
Iowa	135,161	134,782	133,712
Kansas	98,043	97,844	97,446
Total Residential	477,086	475,636	476,617
Commercial:			
Colorado	3,678	3,620	3,590
Nebraska	15,664	15,221	15,218
Iowa	15,398	15,300	15,403
Kansas	9,453	9,469	9,510
Total Commercial	44,193	43,610	43,721
Industrial:			
Colorado	209	208	207
Nebraska	141	149	149
Iowa	94	93	90
Kansas	1,365	1,394	1,351
Total Industrial	1,809	1,844	1,797
Transportation:			
Colorado	30	22	22
Nebraska	4,128	4,270	4,579
Iowa	393	392	389
Kansas	1,142	1,054	1,077
Total Transportation	5,693	5,738	6,067
Other:			
Colorado	—	—	—
Nebraska	—	2	2
Iowa	—	68	71
Kansas	7	8	8
Total Other	7	78	81
Total Customers:			
Colorado	71,413	70,616	69,405
Nebraska	196,319	195,886	199,821
Iowa	151,046	150,635	149,665
Kansas	110,010	109,769	109,392
Total Customers at Year-End	528,788	526,906	528,283

Business Characteristics

Seasonal Variations of Business

Our Electric Utilities and Gas Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as market price. In particular, demand is often greater in the summer and winter months for cooling and heating, respectively. Because our Electric Utilities have a diverse customer and revenue base and we have historically optimized the utilization of our electric power supply resources, the impact on our operations may not be as significant when weather conditions are warmer in the winter and cooler in the summer. Conversely, for our Gas Utilities, natural gas is used primarily for residential and commercial heating, so the demand for this product depends heavily upon weather patterns throughout our service territories, and as a result, a significant amount of natural gas revenue is normally recognized in the heating season consisting of the first and fourth quarters.

Competition

We generally have limited competition for the retail distribution of electricity and natural gas in our service areas. In the past, various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate, but none of these initiatives have been adopted to date, with the exception of Montana. Although we face competition from independent marketers for the sale of natural gas to our industrial and commercial customers, in instances where independent marketers displace us as the seller of natural gas, we still collect a distribution charge for transporting the gas through our distribution network. In Colorado, our electric utility is subject to rules which require competitive bidding for generation supply. Because of these rules, we face competition from other utilities and non-affiliated IPP companies for the right to provide electric energy and capacity for Colorado Electric when resource plans require additional resources.

Regulation and Rates

State Regulation

Our utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. The public utility commissions determine the rates we are allowed to charge for our utility services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of our costs, views concerning appropriate rates of return, the rates of other utilities, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities, and the creation of liens on property located in their state to secure bonds or other securities.

We distribute natural gas in five states. All of our Gas Utilities, and Cheyenne Light's natural gas distribution, have gas cost adjustments that allow us to pass the prudently-incurred cost of gas and certain services through to the customer. In Kansas and Nebraska, we are allowed to recover the portion of uncollectible accounts related to gas costs through the gas cost adjustments. In Kansas, we also have a weather normalization tariff that provides a pass-through mechanism for weather margin variability that occurs from the level used to establish base rates to be paid by the customer as well as tariffs that provide for more timely recovery for certain capital expenditures and fluctuations in property taxes. In 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. In October 2011, the IUB adopted rules that allow rate-regulated natural gas utilities to implement automatic adjustment mechanisms for recovery of certain costs, primarily safety-related and government-mandated investment in infrastructure, between general rate proceedings.

We produce and/or distribute power in four states. The regulatory provisions for recovering the costs to produce electricity vary by state. Certain states have approved specific mechanisms which allow the utility operating in that state to collect, or refund, the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services without filing a general rate case. In some instances, the utility has the opportunity to earn its authorized return on new capital investment. The mechanisms we have in place are:

- In South Dakota, Wyoming, Colorado and Montana, we have cost adjustment mechanisms for our Electric Utilities that serve a purpose similar to the cost adjustment mechanisms in our Gas Utilities. At Cheyenne Light, our pass-through mechanism relating to transmission, fuel and purchased power costs is subject to a $1.0 million threshold: we collect or refund 95% of the increase or decrease that exceeds the $1.0 million threshold, and we absorb the increase or retain the savings for costs below the threshold as well as the 5% not collected or refunded above the threshold.

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

In South Dakota beginning April 1, 2010, the steam plant fuel and conditional ECA were combined into a single cost adjustment called the Fuel and Purchased Power Adjustment clause. The Fuel and Purchased Power Adjustment clause provides for the direct recovery of increased fuel and purchased power costs incurred to serve South Dakota customers. As of April 1, 2010, the Fuel and Purchased Power Adjustment clause was modified in the rate case settlement to contain a power marketing operating income sharing mechanism in which South Dakota customers will receive a credit equal to 65% of power marketing operating income. The modification also adjusts the methodology to directly assign renewable resources and firm purchases to the customer load. In Wyoming beginning June 1, 2010 a similar Fuel and Purchase Power Cost Adjustment was instituted.

- In May 2011, the SDPUC approved an Environmental Improvement Cost Recovery Adjustment tariff. This tariff, which was implemented to recover Black Hills Power's investment of $25 million for pollution control equipment at the PacifiCorp-operated Wyodak plant, went into effect June 1, 2011 and recovers all the costs associated with plant additions.

- In Colorado, we have an ECA for increases or decreases in purchased power and fuel costs and a TCA for transmission cost adjustments. The ECA 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 TCA 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.

- Effective January 1, 2012, the CPUC approved adjustments to the ECA. These adjustments allow for the recovery of transmission expenses paid to other providers, symmetrical interest, and the sharing of off-system sales margins, less certain operating costs, where the customer receives 75% through 2013. This sharing percentage increases to 90% to the customer in 2014.

- In Colorado, beginning in November 2010, the CPUC approved the implementation of a Purchased Capacity Cost Adjustment, the purpose of which is to recover the increase in capacity cost related to Colorado Electric's purchase power agreement with PSCo. This Purchase Capacity Cost Adjustment expired on January 1, 2012 in conjunction with expiration of the PPA with PSCo and the commencement of Colorado Electric's PPA with Colorado IPP.

Certain states where we conduct electric utility operations have adopted renewable energy portfolio standards that require or encourage our Electric Utilities to source, by a certain future date, a minimum percentage of the electricity delivered to customers from renewable energy generation facilities. At December 31, 2011, we were subject to the following renewable energy portfolio standards or objectives:

- South Dakota. South Dakota has adopted a renewable portfolio objective that encourages, but does not mandate utilities to generate, or cause to be generated, at least 10% of their retail electricity supply from renewable energy sources by 2015. Absent a specific renewable energy mandate in South Dakota, our current strategy is to prudently incorporate renewable energy into our resource supply, seeking to minimize associated rate increases for our utility customers.

Montana. Montana established a renewable portfolio standard that requires Black Hills Power to obtain a percentage of its retail electric sales in Montana from eligible renewable resources according to the following schedule: (i) 5% for compliance years 2008-2009; (ii) 10% for compliance years 2010-2014; and (iii) 15% for compliance year 2015 and thereafter. Utilities can meet this standard by entering into long-term purchase contracts for electricity bundled with renewable-energy credits, by purchasing the renewable-energy credits separately, or by a combination of both. The law includes cost caps that limit the additional cost utilities must pay for renewable energy and allows cost recovery from ratepayers for contracts pre-approved by the MTPSC. We are currently in compliance with applicable standards.

- Colorado. Colorado has adopted a renewable energy standard that requires our Colorado Electric subsidiary to generate, or cause to be generated, electricity from renewable energy sources equaling: (i) 12% of retail sales from 2011 to 2014; (ii) 20% of retail sales from 2015 to 2019; and (iii) 30% of retail sales by 2020. Of these amounts, 3% must be generated from distributed generation sources with one-half of these resources being located at customer facilities. The law limits the net annual incremental retail rate impact from these renewable resource acquisitions (as compared to non-renewable resources) to 2% and encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a forward rider mechanism. We are currently in compliance with these standards, and our current strategy is to incorporate renewable energy as required to comply with the standards.

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

Mandatory portfolio standards have increased, and may continue to increase the power supply costs of our electric utility operations. Although we will seek to recover these higher costs in rates, we can provide no assurance that we will be able to secure full recovery of the costs we pay to be in compliance with standards or objectives.

In connection with our acquisition of the Gas Utilities, the CPUC, NPSC, IUB and KCC approved orders or settlement agreements providing that, among other things, (i) our utilities in those jurisdictions cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and (ii) neither Black Hills Utility Holdings nor its utility subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. In addition to the restrictions described above, each state in which we conduct utility operations imposes restrictions on affiliate transactions, including inter-company loans.

Federal Regulation

Energy Policy Act. Black Hills Corporation is a holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and holding companies regulated by FERC under the Federal Power Act and PUHCA 2005.

Federal Power Act. The Federal Power Act gives FERC exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction must maintain tariffs and rate schedules on file with FERC that govern the rates, terms, and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. Public utilities are also subject to accounting, record-keeping, and reporting requirements administered by FERC. FERC also places certain limitations on transactions between public utilities and their affiliates. Our public utility subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our Electric Utilities and our non-regulated subsidiaries, Black Hills Colorado Electric and Black Hills Wyoming, are authorized by FERC to make wholesale sales of electric capacity and energy at market-based rates under tariffs on file with FERC. As a condition of their market-based rate authority, each files Electric Quarterly Reports with FERC. Black Hills Power owns and operates FERC-jurisdictional interstate transmission facilities and provides open access transmission service under tariffs on file with FERC. Our Electric Utilities are subject to routine audit by FERC with respect to their compliance with FERC's regulations.

The Federal Power Act gave FERC authority to certify and oversee a national electric reliability organization with authority to promulgate and enforce mandatory reliability standards applicable to all users, owners, and operators of the bulk-power system. FERC has certified NERC as the electric reliability organization. NERC has promulgated mandatory reliability standards, and NERC, in conjunction with regional reliability organizations that operate under FERC's and NERC's authority and oversight, enforces those mandatory reliability standards.

PUHCA 2005. PUHCA 2005 gives FERC authority with respect to the books and records of a utility holding company. As a utility holding company with centralized service company subsidiaries, Black Hills Service Company and Black Hills Utility Holdings, we are subject to FERC's authority under PUHCA 2005.

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

	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved	Return on Equity	Approved Capital Structure Equity	Approved Capital Structure Debt
Nebraska Gas [1]	Gas	12/2009	9/2010	$12.1	$8.3	10.1 %	52.0 %	48.0 %
Iowa Gas	Gas	6/2008	7/2009	$13.6	$10.8	10.1 %	51.4 %	48.6 %
Iowa Gas [2]	Gas	6/2010	2/2011	$4.7	$3.4	Global Settlement	Global Settlement	Global Settlement
Colorado Gas	Gas	6/2008	4/2009	$2.7	$1.4	10.3 %	50.5 %	49.5 %
Kansas Gas	Gas	5/2009	10/2009	$0.5	$0.5	10.2 %	50.7 %	49.3 %
Black Hills Power [3]	Electric	9/2009	4/2010	$32.0	$15.2	Global Settlement	Global Settlement	Global Settlement
Black Hills Power [4]	Electric	10/2009	6/2010	$3.8	$3.1	10.5 %	52.0 %	48.0 %
Black Hills Power [5]	Electric	1/2011	6/2011	Not Applicable	$3.1	Not Applicable	Not Applicable	Not Applicable
Colorado Electric [6]	Electric	1/2010	8/2010	$22.9	$17.9	10.5 %	52.0 %	48.0 %
Colorado Electric [7]	Electric	4/2011	1/2012	$40.2	$28.0	9.8%-10.2%	49.1 %	50.9 %
Cheyenne Light [8]	Electric/Gas	12/2011	pending	$8.5	pending	pending	pending	pending

(1) In December 2009, Nebraska Gas filed a rate case with the NPSC and interim rates went into effect on March 1, 2010. In August 2010, NPSC issued a decision approving an annual revenue increase of approximately $8.3 million, based on a return on equity of 10.1% with a capital structure of 52% equity effective September 1, 2010. A refund to customers for the difference between interim rates and approved rates was completed in the first quarter of 2011. The Nebraska Public Advocate has filed an appeal with the District Court which has been denied. Subsequently, the Nebraska Public Advocate has filed a notice of appeal in the Court of Appeals. This appeal is still outstanding.

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

(3) In September 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 previous four years. In March 2010, the SDPUC approved a $24.1 million increase in interim rates, subject to refund, effective April 1, 2010 for South Dakota customers. On July 7, 2010, the SDPUC approved a final revenue increase of $15.2 million and a base rate increase of $22.0 million with an effective date of April 1, 2010. The approved capital structure and return on equity are confidential. A refund was provided to customers in the third quarter of 2010.

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

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

(5) In May 2011, the SDPUC approved an Environmental Improvement Cost Recovery Adjustment tariff for Black Hills Power. This tariff, which was implemented to recover Black Hills Power's investment of $25 million for pollution control equipment at the PacifiCorp-operated Wyodak plant, went into effect June 1, 2011 with an annual revenue increase of $3.1 million.

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

Included in the rate case order was a provision that off-system sales margin be shared with customers commencing August 6, 2010. The percentage of margin to be shared with the customers was not resolved at the time of the rate case settlement. The CPUC required that the off-system gross margin earned beginning August 6, 2010 be deferred. The determination of a sharing mechanism for off-system sales was considered as part of the rate case filed with the CPUC by Colorado Electric discussed below.

(7) In April 2011, Colorado Electric filed a request with the CPUC for an annual revenue increase of $40.2 million, or 18.8%, to recover costs and a return on capital associated with the 180 MW generating facility that commenced commercial operation on January 1, 2012, associated infrastructure assets and other utility expenses, including the PPA with Colorado IPP. On December 22, 2011, the CPUC issued an order approving an annual base rate increase of $10.5 million with a rate of return ranging from 9.8% to 10.2% with a capital structure of 49.1% equity and 50.9% debt. New rates were effective January 1, 2012. In addition, approximately $17.5 million of other costs including fuel, purchased power and new transmission will be recovered through normal cost adjustment mechanisms.

The provisions of the order also provided for a sharing mechanism for off-system sales. Colorado Electric has agreed to credit customers 75% for off-system sales margin less certain operating costs, with Colorado Electric retaining 25% through December 31, 2013. The customers' sharing percentage increases to 90% starting in 2014.

(8) On December 1, 2011, Cheyenne Light filed requests for electric and natural gas revenue increases with the WPSC to recover investment in infrastructure and other costs. Cheyenne Light is seeking a $5.9 million increase in annual electric revenue and a $2.6 million increase in annual natural gas revenue.

Environmental Matters

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

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

Environmental Expenditure Estimates	Total (in millions)
2012	$ 12
2013	39
2014	13
Total	$ 64

Water Issues

Our facilities are subject to a variety of state and federal regulations governing existing and potential water/wastewater discharges and protection of surface waters from oil pollution. Generally, such regulations are promulgated under the Clean Water Act and govern overall water/wastewater discharges through NPDES and stormwater permits. All of our facilities that are required to have such permits have those permits in place and are in compliance with discharge limitations and plan implementation requirements. We are not aware of any proposed regulations that will have a significant impact on our operations. Additionally, the EPA regulates surface water oil pollution through its oil pollution prevention regulations. All of our facilities under this program have their required plans in place. Also, the EPA is scheduled to issue updated regulations for wastewater discharge for electric generating units in early 2012, which could have a significant impact on all of our generating fleet.

Air Emissions

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

Clean Air Act

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

Title IV applies to several of our generation facilities, including the Neil Simpson II, Neil Simpson CT, Lange CT, Wygen II, Wygen III and Wyodak plants. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2041. For future plants, we plan to secure the requisite number of allowances by reducing SO_2 emissions through the use of low sulfur fuels, installation of "back end" control technology, use of banked allowances, and if necessary, the purchase of allowances on the open market. We expect to integrate the cost of obtaining the required number of allowances needed for future projects into our overall financial analysis of such new projects.

Title V of the Clean Air Act requires that all of our generating facilities obtain operating permits. All of our existing facilities have received Title V permits, with the exception of Wygen III. Wygen III is allowed to operate under its construction permit until the Title V permit is issued by the state. The Title V application for Wygen III was submitted in January 2011, with the permit expected in 2012. The application was filed in accordance with regulatory requirements.

In 2011, the EPA issued the Industrial and Commercial Boiler Regulations for Area Sources of Hazardous Air Pollutants, which impose emission limits, fuel requirements and monitoring requirements. The rule has an effective date of May 20, 2011 and a compliance deadline of March 21, 2014. This rule has a significant impact on our Neil Simpson I, Osage and Ben French facilities. Engineering evaluations have been completed as to the economic viability of continued operations of these units. In conjunction with the Colorado Clean Air Clean Jobs Act, the CPUC issued an order approving the closure of the W.N. Clark facility no later than December 31, 2013. It is our expectation that the Neil Simpson I, Osage and Ben French units will be closed prior to the March 21, 2014 compliance deadline.

On December 16, 2011, the EPA signed the National Emission Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units (Utility MACT Rule), which became effective on February 16, 2012. Affected units will have three years from the rule effective date to be in compliance, with a pathway defined to apply for a one year extension due to certain circumstances. Certain requirements of that regulation could have significant impacts on the Neil Simpson II, Wygen II, Wygen III and Wyodak plants. Neil Simpson II, Wygen II, Wygen III and the Wyodak plant are expected to be in compliance within the compliance time frame. Significant modifications may be required to ensure compliance at Neil Simpson II and we are working toward that goal. Preliminary estimates of capital requirements to comply with this rule are $30 million to $50 million.

On June 23, 2010, the EPA published in the Federal Register the GHG Tailoring Rule, implementing regulations of GHG for permitting purposes. This rule will impact us in the event of a major modification at an existing facility or in the event of a new major source as defined by EPA regulations. Existing permitted facilities will see monitoring and reporting requirements incorporated into their operating permits upon renewal. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could result in more stringent emission control practices and technologies. As Wyoming state law prohibits regulation of GHG, the EPA will review and develop requirements for that portion of a new source construction permit or for a major modification of an existing source. It is anticipated this additional process will add several months to the permitting process. In addition, unlike a Wyoming issued permit, an appeal of an EPA issued GHG air permit to construct requires an automatic stay to the project, meaning that construction cannot commence until the appeal is resolved. This aspect adds considerable risk to new construction projects as well as to major modifications to existing projects.

In the 2010 legislative session, the State of Colorado passed House Bill 1365, the Colorado Clean Air Clean Jobs Act, a coordinated utility plan to reduce air emissions from coal fired power plants and promote the use of natural gas and other low emitting resources. This act has a significant impact on our W.N. Clark facility and on October 29, 2010, Colorado Electric filed testimony with the CPUC that included a proposal recommending retirement of the W.N. Clark facility. On December 15, 2010, the CPUC issued an order approving closure of the W.N. Clark plant by December 31, 2013. On January 7, 2011, the State Air Quality Control Commission adopted the CPUC order into the Colorado State Implementation Plan and following legislative approval, that plan was submitted in May 2011 to the EPA Region VIII for approval.

In June 2011, the EPA was scheduled to issue proposed Electric Utility New Source Performance Standards for GHG. That publication date has been extended to mid-2012. As the regulations are not yet proposed, we cannot ascertain their impacts but we anticipate they may be applicable to Wygen III. In 2011, it was anticipated the EPA would expedite the issuance of a more stringent ozone ambient air standard. However, the President of the United States postponed this revision and placed it back on its normal review cycle, which is scheduled to occur in 2013. If the lower range of the proposed standard is selected, it is anticipated that Campbell County, Wyoming would be a non-attainment area. Under those conditions, the State of Wyoming may evaluate Neil Simpson II, Wygen II and Wygen III for further reductions in NO_x emissions.

In 2011, the State of Wyoming issued a letter addressing startup and shutdown emissions at Neil Simpson II, requiring the facility to include those emissions in consideration of compliance with the permitted emission limits. This represents a significant change in requirements from the original air permit issued in 1993. As this facility was not designed and built according to those requirements, we are currently undergoing engineering evaluations to determine methods and costs of compliance. We anticipate that the State of Wyoming will eventually issue the same requirements for Wygen I and Wygen II.

Regional Haze

In January 2011, the states of Wyoming and South Dakota submitted their plans to EPA Region VIII, identifying NO_x, SO_2 and particulate matter emission reductions intended to meet the Class I Areas (National Parks and Wilderness Areas) visibility improvement requirements under the EPA's Regional Haze Program. Although none of our South Dakota or Wyoming power plants were included in those plans, we anticipate that within the next five years, Ben French, Neil Simpson I and Osage will be included. This is based on recent activity by EPA Region VIII, where they have rejected at least in part, states' emission reduction plans. Colorado submitted a revised plan to the EPA in May 2011, addressing the additional required emission reductions, which for the first time included our W.N. Clark facility. In 2011, the EPA partially rejected North Dakota's Regional Haze Plan, and issued a Federal Implementation Plan, dictating new lower emission limits for certain facilities. As Ben French, Neil Simpson 1 and Osage have no SO_2 or NO_x post combustion emission controls and are in close proximity to the two Class I Areas in western South Dakota, we fully expect they will be brought into the program. This could occur in the very near future, if the EPA rejects the South Dakota and/or Wyoming Plans, or it could occur in five years, when the plans undergo the required five year review to assess visibility improvement progress. Costs to comply will be significant and have been included as part of the engineering review conducted to assess impacts of the EPA's Industrial and Commercial Boiler Area Source regulations. It is our expectation Ben French, Osage and Neil Simpson I will be closed prior to March 21, 2014.

Mercury Regulations

Approximately 50% of our electric generating capacity is coal-fired. On December 16, 2011, the EPA signed the National Emission Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units (MATS) and this regulation became effective February 16, 2012. Affected units will have three years from the rule effective date to be in compliance with a pathway defined to apply for a one year extension due to certain circumstances. This rule will address mercury emissions, among other pollutants, at Neil Simpson II, Wygen II and Wygen III.

The MATS rule will require significant investments at our power generating facilities. Of our affected units, it is anticipated that Neil Simpson II will require the most extensive investments. The state air permit for Wygen II and Wygen III provides mercury emission limits and monitoring requirements with which we are in compliance. Wygen II has been utilized for study and review of mercury emission control technology and has mercury monitors in place. In 2009, we added mercury monitors to our Neil Simpson II plant. The Wygen III plant, which commenced operations in 2010, also has mercury monitors. Federal multi-pollutant legislation is also being considered that would require reductions similar to the EPA rules and may add requirements for the reduction of GHG emissions.

Greenhouse Gas Regulations

We utilize a diversified energy portfolio of power generation assets that includes a fuel mix of coal and natural gas as well as wind sources, and minimal quantities of both solar and hydroelectric power. Of these generation resources, coal-fired power plants are the most significant sources of CO_2 emissions. Although we cannot predict specifically how, if or when, GHG will be regulated, any federally mandated GHG reductions or limits on CO_2 emissions could have a material impact on our financial position, results of operations, or cash flows. In 2011, the EPA's GHG Tailoring Rule went into effect, requiring GHG emissions to be addressed in new major source construction permits and to be addressed upon renewal of Title V Operating Permits. As there are no emission standards or caps currently in place, we cannot predict how this requirement will impact our existing facilities upon permit renewal. In 2011, we reported 2010 GHG emissions from our Power Generation and Gas Utilities in order to comply with the EPA's GHG Annual Inventory regulation, issued in 2009. In addition to federal legislative activity, GHG regulations have been proposed in various states and alleged climate change issues are the subject of a number of lawsuits, the outcome of which could impact the utility industry. We will continue to review GHG impacts as legislation or regulation develops and litigation is resolved.

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

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

Solid Waste Disposal

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

As of October 1, 2010, we suspended operations at the Osage power plant. It has an on-site ash impoundment that is near capacity. An application to close the impoundment was filed with the State of Wyoming on November 3, 2010 and site closure work is underway. If Osage should ever re-start, ash disposal will be at our WRDC 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. For our Pueblo Airport Generation site in Pueblo, CO, we have posted a bond with the State of Colorado to cover the costs of remediation for a waste water containment pond permitted to provide wastewater storage and processing for this zero discharge facility.

Agreements are in place that require PacifiCorp and MEAN to be responsible for any costs related to the solid waste from their ownership interest in the Wyodak plant and Wygen I plant, respectively. As operator of Wygen III, Black Hills Power has a similar agreement in place for any such costs related to solid waste from Wygen III. Under their separate, related operating agreement, Black Hills Power, MDU and the City of Gillette each share the costs for solid waste from Wygen III according to their respective ownership interests.

Additional unexpected material costs could also result in the future if any regulator determines that solid waste from the burning of coal contains a hazardous material that requires special treatment, including previously disposed solid waste. In that event, the regulatory authority could hold entities that disposed of such waste responsible for remedial treatment. On June 21, 2010, the EPA published in the Federal Register the proposed coal combustion residuals regulations. The regulations are complex and contain various options for ash management that the EPA will be selecting from to form the final version of the rule. We cannot determine the likely impact on our operations until the final version of the rule is known, which is currently expected to be mid-2012. However, if ash becomes subject to regulations as a hazardous waste, implementation requirements could have a material impact on our financial position, results of operations or cash flows.

Past Operations

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

As a result of the Aquila Transaction, we acquired whole and partial liabilities for several former manufactured gas processing sites in Nebraska and Iowa. The acquisition provided for a $1.0 million insurance recovery, now valued at $1.1 million, which will be used to help offset remediation costs. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the financial viability of other responsible parties.

In March 2011, Nebraska Gas executed an Allocation, Indemnification and Access Agreement with the successor to the operator of the Nebraska former manufactured gas plants. Under this agreement, Nebraska Gas received $1.87 million from the successor to the operator for Nebraska Gas to remediate two sites in Nebraska and the successor would be responsible for remediation activity at the two remaining sites in Nebraska. Subsequent to this transaction, Nebraska Gas enrolled the two sites (Blair and Plattsmouth) in Nebraska's Voluntary Cleanup Program and remediation activities have commenced, with a target completion date of third quarter 2012. As of December 31, 2011, our effective liabilities for the manufactured gas plant sites currently range from approximately $2.9 to $6.1 million.

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

Non-regulated Energy Group

Our Non-regulated Energy Group, which operates through various subsidiaries, acquires, explores for, develops and produces natural gas and crude oil primarily in the Rocky Mountain region; produces and sells electric capacity and energy through a portfolio of generating plants; and produces and sells coal from our mine located in the Powder River Basin in Wyoming. The Non-regulated Energy Group consists of three business segments for reporting purposes:

- Oil and Gas
- Power Generation
- Coal Mining

For more than 15 years, we have also owned and operated, Enserco, an energy marketing business that engages in natural gas, crude oil, coal, power and environmental marketing and trading in the United States and Canada. In January 2012, we entered into a definitive agreement to sell Enserco, which resulted in our Energy Marketing segment being reported as discontinued operations. This transaction is expected to close in the first quarter of 2012. For comparative purposes, all prior periods presented have been restated to reflect the reclassification of this segment to discontinued operations on a consistent basis.

Oil and Gas Segment

Our Oil and Gas segment, which conducts business through BHEP and its subsidiaries, acquires, explores for, develops and produces natural gas and crude oil primarily in the Rocky Mountain region. As of December 31, 2011, the principal assets of our Oil and Gas segment included: (i) operating interests in crude oil and natural gas properties, including properties in the San Juan Basin (including holdings primarily on the tribal lands of the Jicarilla Apache Nation in New Mexico and Southern Ute Nation in Colorado), the Powder River Basin (Wyoming) and the Piceance Basin (Colorado); (ii) non-operated interests in crude oil and natural gas properties including wells located in the Williston (Bakken Shale in North Dakota), Wind River (Wyoming), Bear Paw Uplift (Montana), Arkoma (Oklahoma), Anadarko (Texas) and Sacramento (California) basins; and (iii) a 44.7% 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, 2011, we had total reserves of approximately 133 Bcfe, of which natural gas comprised 72% and crude oil comprised 28%. The majority of our reserves are located in select crude oil and natural gas producing basins in the Rocky Mountain region. Approximately 34% of our reserves are located in the San Juan Basin of northwestern New Mexico, primarily in the East Blanco Field of Rio Arriba County; 23% are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field of Weston and Niobrara counties; and 21% are located in the Piceance Basin of western Colorado, primarily in Mesa county.

Delivery Commitments

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

Summary Oil and Gas Reserve Data

The summary information presented concerning our estimated proved developed and undeveloped oil and gas reserves and the 10% discounted present value of estimated future net revenues is based on reports prepared by Cawley Gillespie & Associates, an independent consulting and engineering firm located in Fort Worth, Texas. Reserves were determined consistent with SEC requirements using a 12-month average price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties. Estimates of economically recoverable reserves and future net revenues are based on a number of variables, which may differ from actual results. Reserves for oil and gas are reported separately and then combined for a total MMcfe (where oil in Mbbl is converted to an MMcfe basis by multiplying Mbbl by six).

The SEC definition of "reliable technology" permits the use of any reliable technology to establish reserve volumes in addition to those established by production and flow test data. This definition allows, but does not require us, to book PUD locations that are more than one location away from a producing well. We conservatively elected to only include PUDs which are one location away from a producing well in our volume reserve estimate. Companies are permitted but not required to disclose probable and possible reserves. We have elected not to report on these additional reserve categories. Additional information on our oil and gas reserves, related financial data and the SEC requirements can be found in Note 21 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

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

CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Zane Meekins. Mr. Meekins has been practicing consulting petroleum engineering since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas and has over 23 years of practical experience in petroleum engineering and over 21 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

BHEP's Manager of Planning and Analysis is the technical person primarily responsible for overseeing our third party reserve estimates. He has over 31 years of exploration and production industry experience as a geologist and financial analyst. He has over 21 years of experience working closely with internal and third party qualified reserve estimators in major and mid-sized oil and gas companies. He holds a Bachelor of Science degree in Geology and a Masters in Business Administration.

The following tables set forth summary information concerning our estimated proved developed and undeveloped reserves, by basin, as of December 31, 2011, 2010 and 2009:

Proved Reserves		December 31, 2011				
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed -						
Natural Gas (MMcf)	71,867	15,598	36,463	1,954	8,926	8,926
Oil (Mbbl)	4,830	—	12	1,247	3,549	22
Total Developed (MMcfe)	100,847	15,598	36,535	9,436	30,220	9,058
Undeveloped -						
Natural Gas (MMcf)	24,031	12,765	8,132	2,102	—	1,032
Oil (Mbbl)	1,394	—	—	1,394	—	—
Total Undeveloped (MMcfe)	32,395	12,765	8,132	10,466	—	1,032
Total MMcfe	133,242	28,363	44,667	19,902	30,220	10,090

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

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

Change in Proved Reserves

The following tables summarize the change in quantities of proved developed and undeveloped reserves by basin, estimated using SEC-defined product prices, as of December 31, 2011, 2010 and 2009:

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

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

(a) Included in the total revisions are (23.6) Bcfe for dropped PUD locations due to five year aging of reserves which was offset by positive performance revisions of 2.3 Bcfe in various basins. Revisions due to cost and commodity pricing were less than 1% of total reserve quantities.

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

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

(b) Revisions to previous estimates for 2011 were primarily due to the SEC requirement that proved undeveloped locations must be developed within five years or must be removed from proved undeveloped reserves.

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

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

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

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

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

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

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

(a) Revisions to previous estimates for 2009 primarily due to price changes.
(b) Production for reserve calculations does not include volumes for NGLs.

Production Volumes

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

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

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

Other Information

	December 31, 2011	December 31, 2010
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	76 %	72 %
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis	24 %	28 %
Present value of estimated future net revenues, before tax, discounted at 10% (in thousands)	$255,087	$196,554

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

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

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

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

Drilling Activity

The following tables reflect the wells completed through our drilling activities for the last three years. In 2011, we participated in drilling 31 gross (10 net) development and exploratory wells, with a net well success rate of 83%. A development well is a well drilled within a proved area of a reservoir known to be productive. An exploratory well is a well drilled to find and/or produce oil or gas in an unproved area, to find a new reservoir in a previously productive field or to extend a known reservoir. Gross wells represent the total wells we participated in, regardless of our ownership interest, while net wells represent the sum of our fractional ownership interests within those wells.

Year ended December 31,	2011		2010		2009	
Net Development Wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	—	—	—	—	—	—
San Juan	1.00	—	5.60	—	3.00	—
Williston	1.73	—	0.67	—	0.04	—
Powder River	—	—	2.66	—	—	—
Other	3.59	—	—	—	4.37	1.04
Total net development wells	6.32	—	8.93	—	7.41	1.04

Year ended December 31,	2011		2010		2009	
Net Exploratory Wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	0.99	—	—	—	0.91	—
San Juan	0.80	—	—	—	—	—
Williston	—	—	—	—	0.03	—
Powder River	—	—	—	—	—	0.50
Other	0.25	1.70	—	—	0.50	0.37
Total net exploratory wells	2.04	1.70	—	—	1.44	0.87

As of December 31, 2011, we were participating in the drilling of 29 gross (2.22 net) wells, which had been commenced but not yet completed.

Recompletion Activity

Recompletion activities for the years ended December 31, 2011, 2010 and 2009 were insignificant to our overall oil and gas operations.

Productive Wells

The following table summarizes our gross and net productive wells at December 31, 2011, 2010 and 2009:

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

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

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

Acreage

The following table summarizes our undeveloped, developed and total acreage by location as of December 31, 2011:

	Undeveloped		Developed		Total	
	Gross	Net *	Gross	Net	Gross	Net
Piceance	39,569	30,816	37,326	33,194	76,895	64,010
San Juan	40,997	39,569	26,142	22,725	67,139	62,294
Williston	18,796	1,910	40,301	5,600	59,097	7,510
Powder River	79,439	41,651	32,804	17,091	112,243	58,742
Bear Paw Uplift (MT)	351,119	63,428	106,748	19,877	457,867	83,305
Other	66,002	46,141	28,584	5,653	94,586	51,794
Total	595,922	223,515	271,905	104,140	867,827	327,655

* Approximately 4.7% (52,061 gross and 10,492 net acres) and 15.8% (125,063 gross and 35,120 net acres) and 6.5% (59,832 gross and 14,362 net acres) of our net undeveloped acreage could expire in 2012, 2013 and 2014, respectively, if production is not established on the leases or further action is not taken to extend the associated lease terms. Decisions on extending leases are based on expected exploration or development potential under the prevailing economic conditions.

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

Seasonality of Business. Weather conditions affect the demand for, and prices of, natural gas and can also temporarily inhibit production and delay drilling activities, which in turn impacts our overall business plan. The demand for natural gas is typically higher in the fourth and first quarters of our fiscal year, which sometimes results in higher natural gas prices. Due to these seasonal fluctuations, results of operations on a quarterly basis may not reflect results which may be realized on an annual basis.

Regulation. Crude oil and natural gas development and production activities are subject to various laws and regulations governing a wide variety of matters. Regulations often require multiple permits and bonds to drill, complete or operate wells, and establish rules regarding the location of wells, the well construction, 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 and plant 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 crude oil and natural gas properties. Some states allow the forced pooling or integration of tracts to facilitate exploration, when voluntary pooling of lands and leases cannot be accomplished. The effect of these regulations may limit the number of wells or the locations where we can drill.

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

In addition to being subject to federal and tribal regulations, we must also comply with state and county regulations, which have been going through significant change over the last several years. For example, in 2008 new state regulations were implemented in New Mexico which increased the regulatory requirements associated with drilling pits. Colorado legislation in 2007 changed the structure of the oil and gas commission, which has subsequently developed and approved significant changes to oil and gas regulations which were implemented in 2009. Changes such as these have increased costs and added uncertainty with respect to the timing and receipt of permits. We expect additional changes of this nature to occur in the future.

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

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

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on our crude oil and natural gas properties. Hydraulic fracturing involves using mostly water, sand, and a small amount of certain chemicals to fracture the hydrocarbon-bearing rock formation to enhance flow of hydrocarbons into the well-bore. The process is regulated by state oil and natural gas commissions; however, the EPA does assert federal regulatory authority over certain hydraulic fracturing activities when diesel comprises part of the fracturing fluid. In addition, several agencies of the federal government including the EPA and the BLM are conducting studies of the fracturing stimulation process, which may result in additional regulations. In the event federal, state, local or municipal legal restrictions are adopted in areas where we are conducting, or plan to conduct operations, we may incur additional costs to comply with such regulations, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from utilizing fracture stimulation which may effectively preclude the drilling of wells.

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

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

Greenhouse Gas Regulations. The Oil and Gas segment is impacted by regulation in the state of New Mexico. The EPA published an amendment to its GHG reporting requirements in the November 2010 Federal Register, adding Petroleum and Natural Gas Systems to the mandatory annual reporting requirements. Data gathering commenced on January 1, 2011, with the final report to the EPA due in first quarter of 2012. Other states may implement their own such programs in the future.

Power Generation Segment

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops and operates our non-regulated power plants. As of December 31, 2011, we held varying interests in independent power plants operating in Wyoming and Colorado with a total net ownership of 309 MW. In January 2011, we sold our ownership interests in the Idaho partnerships which own the Idaho facilities.

Portfolio Management

We sell capacity and energy under a combination of mid- to long-term contracts, which mitigates the impact of a potential downturn in future power prices. We currently sell a substantial majority of our non-regulated generating capacity under contracts having terms greater than one year. We sell additional power into the wholesale power markets from our generating capacity when it is available and economical.

As of December 31, 2011, 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	Coal	Gillette, Wyoming	76.5%	68.9	2003

Power Plant	Fuel Type	Location	Ownership Interest	Owned and Leased (MW)	Start Date
				108.9	
Pueblo Airport Generation (2)	Gas	Pueblo, CO	100.0%	200.0	2012
Total Owned Capacity				308.9	

(1) On January 18, 2011, we sold our ownership interest in the partnerships that owned the Glenns Ferry and Rupert Cogeneration facilities.

(2) The plant commenced commercial operation on January 1, 2012. Black Hills Colorado IPP has the obligation to operate this facility under the 20-year PPA which is accounted for as a capital lease.

Black Hills Wyoming - Gillette CT. The Gillette CT is a simple-cycle, gas-fired combustion turbine located at our Gillette, Wyoming energy complex. The facility's energy and capacity is sold to Cheyenne Light under a 3-year PPA that expires in August 2014.

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

Black Hills Colorado IPP - Pueblo Airport Generation. The Pueblo Airport Generation facility is two 100 MW combined-cycle gas-fired power generation plants constructed to fulfill a 20-year PPA with Colorado Electric. The plants commenced operation on January 1, 2012, and the assets are accounted for as a capital lease under a 20-year PPA with Colorado Electric.

Competition. The independent power industry consists of many strong and capable competitors, some of which may have more extensive operating experience, or greater financial resources than we possess.

With respect to the merchant power sector, FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity, and foster competition within the wholesale electricity markets. In addition, the deregulation efforts that caused some vertically integrated utilities to separate their generation, transmission, and distribution businesses have slowed considerably since the merchant energy crisis in 2001. Our Power Generation business could face greater competition if utilities are permitted to robustly invest in power generation assets. However, regulatory pressures for utilities to competitively bid generation resources may provide their own upside opportunity for independent power producers in some regions.

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

The Energy Policy Act of 1992. The passage of the Energy Policy Act of 1992 encouraged independent power production by providing certain exemptions from regulation for EWGs. EWGs are exclusively in the business of owning or operating, or both owning and operating, eligible power facilities and selling electric energy at wholesale. EWGs are subject to FERC regulation, including rate regulation. We own two EWGs: Wygen I and Gillette CT. Our EWGs have been granted market-based rate authority, which allows FERC to waive certain accounting, record-keeping and reporting requirements imposed on public utilities with cost-based rates.

Clean Air Act. The Clean Air Act impacts our Power Generation business in a manner similar to the impact disclosed for our regulated Electric Utilities. Our Gillette CT and Wygen I facilities are subject to Titles IV and V of the Clean Air Act and have the required permits in place. As a result of SO_2 allowances credited to us from the installation of sulfur removal equipment at our jointly owned Wyodak plant, we hold sufficient allowances for our Gillette CT and Wygen I plants through 2040, without purchasing additional allowances. The EPA's Utility MACT rule described in the Utilities Group section will apply to Wygen I. The EPA's GHG Tailoring Rule described in the Utilities Group section will apply to the Gillette CT and Wygen I upon a major modification or upon operating permit renewal.

Clean Water Act. The Clean Water Act impacts our Power Generation business in a manner similar to the impact described above for our regulated Electric Utilities. Each of our facilities that is required to have NPDES permits have those permits and are in compliance with discharge limitations. Also, as the EPA regulates surface water oil pollution prevention through its oil pollution prevention regulations, each of our facilities regulated under this program have the requisite plans in place.

Solid Waste Disposal. We dispose of all Wygen I coal ash and scrubber wastes in mined areas at our WRDC coal mine under the terms and conditions of a state permit. The factors discussed under this caption for the Utilities Group also impact our Power Generation segment in a similar manner.

Greenhouse Gas Regulations. The factors discussed under this caption for the Utilities Group also apply to our Power Generation segment.

Coal Mining Segment

Our Coal Mining segment operates through our WRDC subsidiary. We mine, process and sell low-sulfur coal at our coal mine near Gillette, Wyoming. The WRDC coal mine, which we acquired in 1956 from Homestake Gold Mining Company, is located in the Powder River Basin. The Powder River Basin contains one of the largest coal reserves in the United States. We produced approximately 5.7 million tons of coal in 2011. In a basin characterized by thick coal seams, our overburden ratio, a comparison of the cubic yards of dirt removed to a ton of coal uncovered, has in recent years trended upwards to a ratio of approximately 2.6:1 at December 31, 2011. The overburden ratio is expected to decrease in the latter part of 2012 and remain at a lower ratio for the next several years when mining operations are relocated to a different area of the mine property.

Mining rights to the coal are based on four federal leases and one state lease. We pay federal and state royalties of 12.5% and 9.0%, respectively, of the selling price of all coal. As of December 31, 2011, we had coal reserves of approximately 256.2 million tons, based on internal engineering studies. The reserve life is equal to approximately 57 years at expected production levels.

Substantially all of our coal production is currently sold under mid-term 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 under which PacifiCorp is obligated to purchase a minimum of 1.5 million tons of coal each year of the contract term, subject to adjustments for planned outages. This contract expires at the end of December 2022;
- The 110 MW Wygen III power plant owned 52% by Black Hills Power, 25% by MDU and 23% by the City of Gillette;
- The 90 MW non-regulated mine-mouth power plant, Wygen I, owned 76.5% by Black Hills Wyoming and 23.5% by MEAN; and
- Certain regional industrial customers served by truck.

Our Coal Mining segment sells coal to Black Hills Power and Cheyenne Light for all of their requirements under agreements that limit earnings from these affiliate coal sales to a specified return on our coal mine's cost-depreciated investment base. The return is 4% (400 basis points) above A-rated utility bonds, to be applied to our coal mining investment base as determined each year. Black Hills Power made a commitment to the SDPUC, the WPSC and the City of Gillette that coal for Black Hills Power's operating plants would be furnished and priced as provided by that agreement for the life of the Neil Simpson II plant, which was placed into service in 1995. The agreement with Cheyenne Light provides coal for the life of the Wygen II plant.

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 at the end of 2022. The price for coal sold to PacifiCorp for its Dave Johnston plant was determined by a coal supply agreement that terminated in December 2011. We supplied the Dave Johnston plant with approximately 1.7 million tons of coal per year.

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

WRDC supplies coal to Black Hills Wyoming for the Wygen I generating facility for requirements under an agreement using a base price that includes price escalators and quality adjustments through June 30, 2038 and includes actual costs per ton plus a margin equal to the yield for Moody's A-Rated 10-Year Corporate Bond Index plus 4% with the base price being adjusted on a 5-year interval. The agreement stipulates that WRDC will supply coal to the 90 MW Wygen 1 plant through June 30, 2038.

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

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

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

Ash from our South Dakota and Wyoming power plants, as well as PacifiCorp's Wyodak Power Plant, is disposed of in the mine and is utilized for backfill to meet permitted post-mining contour requirements. The EPA has proposed national disposal regulations that include multiple options, one of which regulates coal ash as a hazardous waste. The public comment period ended in November 2010, and a final rule is expected in mid-2012. While the proposed combustion residuals regulations do not address mine backfill, it is widely expected that the U.S. Office of Surface Mining will collaborate with the EPA to address mine backfill in the near future. If the ash is regulated as a hazardous waste, implementation requirements will likely increase the cost of disposal.

Mine Reclamation. Under applicable law, we must submit applications to, and receive approval from, the WDEQ for any mining and reclamation plan that provides for orderly mining, reclamation, and restoration of the WRDC mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. The WRDC coal mine is permitted to operate under a five year mining permit issued by the State of Wyoming. The current permit was re-issued on May 4, 2011 and expires in 2016. Based on extensive reclamation studies, we have accrued approximately $17.2 million for reclamation costs as of December 31, 2011. Mining regulatory requirements continue to increase, which impose additional cost into the mining process.

Other Properties

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

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

- Approximately 8,800 square feet for an operations and customer call center in Rapid City, South Dakota;
- Approximately 37,600 square feet for a customer call center in Lincoln, Nebraska;
- Approximately 47,430 square feet of office space in Denver, Colorado; and
- Other offices and warehouse facilities located within our service areas.

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

Employees

At December 31, 2011, we had 2,030 full-time employees. Approximately 33% of our employees are represented by a collective bargaining agreement. We have not experienced any labor stoppages in recent years. At December 31, 2011, approximately 24% of our Utilities Group employees were eligible for regular or early retirement.

The following table sets forth the number of employees by business group:

	Number of Employees
Corporate	391
Utilities	1,451
Non-regulated Energy *	188
Total	2,030

* Excludes 44 Energy Marketing employees of our discontinued operations subsidiary, Enserco, due to the proposed sale of Enserco.

At December 31, 2011, 664 employees (all within the Utilities Group) were covered by the following collective bargaining agreements:

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Black Hills Power	161	IBEW Local 1250	March 31, 2012
Cheyenne Light	48	IBEW Local 111	June 30, 2016
Colorado Electric	138	IBEW Local 667	April 15, 2015
Iowa Gas	137	IBEW Local 204	August 1, 2015
Kansas Gas	21	Communications Workers of America, AFL-CIO Local 6407	December 31, 2014
Nebraska Gas	159	IBEW Local 244	March 13, 2014
Total	664		

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, or otherwise.

Regulatory commissions may refuse to approve some or all of the utility rate increases we have requested or may request in the future, or may determine that amounts passed through to customers were not prudently incurred and therefore, are not recoverable which could adversely affect our results of operations, financial position or liquidity.

Our regulated electric and gas utility operations are subject to cost-of-service regulation and earnings oversight from federal and state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our retail electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. The rates that we are allowed to charge may or may not match our related costs and allowed return on invested capital at any given time. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the state public utility commissions will judge all of our costs, including our borrowing and debt service costs, to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that produce a full recovery of our costs and the return on invested capital allowed by the applicable state public utility commission.

To some degree, each of our gas and electric utilities in South Dakota, Wyoming, Colorado, Montana, Nebraska, Iowa and Kansas are permitted to recover certain costs (such as increased fuel and purchased power costs) without having to file a rate case. To the extent we are able to pass through such costs to our customers and a state public utility commission subsequently determines that such costs should not have been paid by the customers, we may be required to refund such costs. Any such costs not recovered through rates, or any such refund, could adversely affect our results of operations, financial position or liquidity.

The sale of Enserco may be delayed or not be completed, which could adversely affect our results of operations. The operating results of Enserco between year-end and completion of the sale may be negatively impacted by the announcement of the sale and/or other risks inherent to that business, and the sale of Enserco may be delayed or not be completed, either of which could adversely affect our results of operations, financial position or liquidity.

In January 2012, we entered into a definitive agreement to sell Enserco, our non-regulated Energy Marketing segment. We expect the sale to close in the first quarter of 2012. We will continue to operate the Enserco business until the sale is completed. This business is subject to a variety of risks inherent to trading activities, including:

- Commodity prices can often be volatile. A decline in oil and natural gas price volatility could affect our revenues and returns from our trading activities at Enserco, which tend to increase when markets are volatile.

- Derivative instruments are used in conjunction with our trading activities to limit a portion of the potential adverse effects resulting from changes in commodity prices and foreign exchange rates. Even though they are closely monitored by Management, our hedging and trading activities can result in losses. Depending upon regulations adopted by the CFTC, we could be required to post additional collateral with our dealer counterparties for our commitments. Such a requirement could have a significant impact on our ability to execute derivative transactions and on cash flow.

- The operations of Enserco rely on storage and transportation assets owned by third parties to satisfy their obligations. We depend on pipelines and other storage and transportation facilities owned by third parties to satisfy our delivery obligations under contracts to buy and sell natural gas, crude oil, coal and other commodities, which are settled by physical delivery.

- Enserco may be subject to increased regulation, which may limit position limits and opportunity for various transactions.

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- The global financial situation has affected our counterparty credit risk, and as a consequence the creditworthiness of many of our contractual counterparties (particularly financial institutions) has deteriorated. Additionally, economic conditions may cause increased late payments and uncollectible accounts. Even though we have established guidelines, controls and limits to manage and mitigate credit risk and this is monitored closely by management, to the extent economic conditions cause our credit exposure to contractual counterparties to increase materially, such increased exposure could have a material adverse effect on Energy Marketing's results of operations, liquidity and financial position.

We will not be able to complete the sale of Enserco until we obtain regulatory approval from FERC. If this regulatory approval is not received, then the parties will not be obligated to complete the transaction.

In addition, the sale is subject to customary conditions and the transaction may not be completed if a portion of the business suffers a material adverse effect between the signing of the stock purchase agreement and the closing. The value placed on Enserco is based on the value of its trading activities and the value of its midstream assets. As agreed to in the stock purchase agreement, we have committed to certain business curtailment actions relating to our proprietary trading and certain working capital requirements. Uncertainty about the effect of the sale on employees and customers may have an adverse effect on us, regardless of whether the transaction is eventually completed. Although we have taken steps to reduce any adverse effects, these uncertainties may impair our ability to retain employees and customers and others who deal with us may seek to change existing business relationships.

Although actual results could differ materially from our expectations, after closing costs and other adjustments, we do not anticipate the transaction to result in a significant gain or loss. However, this expectation could change due to several factors including, but not limited to, changes in the market value of natural gas inventory and certain other contracts and changes in the estimate of transaction costs and other costs associated with closing out Enserco Energy's operations.

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

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

We cannot be certain that the IRS will accept our tax positions. If the IRS successfully sought to assert contrary tax positions, we could be required to pay a significant amount of these deferred taxes earlier than currently forecasted. In certain circumstances, the IRS may assess penalties when challenging our tax positions. If we were unsuccessful in defending against these penalties, it may have a material impact on our results of operations.

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

We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, SEC-defined commodity prices and recent costs are utilized. Such prices and costs are utilized except when different prices and costs are fixed and determinable from applicable contracts for the remaining term of those contracts. Two primary factors in the ceiling test are natural gas and crude oil reserve levels and SEC-defined crude oil and gas prices, both of which impact the present value of estimated future net revenues. Revisions to estimates of natural gas and crude oil reserves, or an increase or decrease in prices, can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense.

We recorded a non-cash impairment charge in the first quarter of 2009 due to the full cost ceiling limitations. We may have to record additional non-cash impairment charges in the future if commodity prices drive the SEC-defined prices below levels that precipitated the 2009 impairment. Using our year-end reserve information, a price sensitivity analysis indicates that there is a risk of a ceiling test impairment if the average realized gas price drops below $2.80 per Mcf, holding all other variables constant. See Note 12 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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

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

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

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

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

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on our crude oil and natural gas properties. Hydraulic fracturing involves using mostly water, sand, and a small amount of certain chemicals to fracture the hydrocarbon-bearing rock formation to enhance flow of hydrocarbons into the well-bore. The process is typically regulated by state crude oil and natural gas commissions; however, the EPA does assert federal regulatory authority over certain hydraulic fracturing activities when diesel comprises part of the fracturing fluid. In addition several agencies of the federal government including the EPA and the BLM are conducting studies of the fracturing stimulation process which may result in additional regulations. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide the federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process.

Certain states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In the event federal, state, local or municipal legal restrictions are adopted in areas where we are conducting or in the future plan to conduct operations, we may incur additional costs to comply with such regulations that may be significant, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from utilizing fracture stimulation and effectively preclude the drilling of wells.

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

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

Our current or future development, expansion and acquisition activities may not be successful, which could impair our ability to execute our growth strategy.

Execution of our future growth plan is dependent on successful ongoing and future development, expansion and acquisition activities. We can provide no assurance that we will be able to complete development projects or acquisitions we undertake or continue to develop attractive opportunities for growth. Factors that could cause our activities to be unsuccessful include:

- Our inability to obtain required governmental permits and approvals;
- Our inability to obtain financing on acceptable terms, or at all;
- The possibility that one or more credit rating agencies would downgrade our issuer credit rating to below investment grade, thus increasing our cost of doing business;
- Our inability to successfully integrate any businesses we acquire;
- Our inability to retain management or other key personnel;
- Our inability to negotiate acceptable acquisition, construction, fuel supply, power sales or other material agreements;
- The trend of utilities building their own generation or looking for developers to develop and build projects for sale to utilities under turnkey arrangements;
- 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, our oil and gas reserves and our generation capacity;
- Fuel prices or fuel supply constraints;
- Pipeline capacity and transmission constraints; and
- Competition.

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

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

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

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

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

- The inability to obtain required governmental permits and approvals along with the cost of complying with or satisfying conditions imposed upon such approvals;
- Contractual restrictions upon the timing of scheduled outages;
- Cost of supplying or securing replacement power during scheduled and unscheduled outages;
- The unavailability or increased cost of equipment;
- The cost of recruiting and retaining or the unavailability of skilled labor;
- Supply interruptions, work stoppages and labor disputes;
- Capital and operating costs to comply with increasingly stringent environmental laws and regulations;
- Opposition by members of public or special-interest groups;
- Weather interferences;
- Unexpected engineering, environmental and geological problems; and
- Unanticipated cost overruns.

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

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

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

Our coal mining operations are subject to operating risks that are beyond our control which could affect our profitability and production levels. Our surface mining operations could be disrupted or materially affected due to adverse weather or natural disasters such as heavy snow, rain or flooding.

Prices for some of our products and services as well as a portion of our operating costs are volatile and may cause our revenues and expenses to fluctuate significantly.

A portion of our net income is attributable to sales of contract and off-system wholesale electricity and natural gas 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 crude oil and natural gas operations is affected by the prevailing market prices of crude oil and natural gas. Crude oil and natural gas prices and markets historically have also been, and are likely to continue to be, volatile. A decrease in crude oil or natural gas prices would not only reduce revenues and profits, but would also reduce the quantities of reserves that are commercially recoverable, and may result in charges to earnings for impairment of the net capitalized cost of these assets. Crude oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for crude oil and natural gas, market uncertainty, and a variety of additional factors that are beyond our control.

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

Our mining operation requires reliable supplies of replacement parts, explosives, fuel, tires and steel-related products. If the cost of these increase significantly, or if sources of supplies and mining equipment become unavailable to meet our replacement demands, our productivity and profitability could be lower than our current expectations. In recent years, industry-wide demand growth exceeded supply growth for certain surface mining equipment and off-the-road tires. As a result, lead times for procuring some items generally increased to several months and prices for these items increased significantly.

Our hedging activities that are designed to protect against commodity price and financial market risks may cause fluctuations in reported financial results due to accounting requirements associated with such activities.

We use various financial contracts and derivatives, including futures, forwards, options and swaps, to manage commodity price and financial market risks. The timing of the recognition of gains or losses on these economic hedges in accordance with GAAP does not always match up with the gains or losses on the commodities or assets being hedged. The difference in accounting can result in volatility in reported results, even though the expected profit margin may be essentially unchanged from the dates the transactions were consummated.

Derivatives regulations included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

In July 2010, Dodd-Frank was passed by Congress and signed into law. Dodd-Frank contains significant derivatives regulations, including a requirement that certain transactions be cleared on exchanges and a requirement to post cash collateral (commonly referred to as "margin") for such transactions. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. Dodd-Frank requires the CFTC to promulgate rules to define these terms. However, CFTC has not yet done so and we do not know whether the rules or exceptions thereto will apply to us.

We use crude oil and natural gas derivative instruments to hedge the sales price for a portion of our expected oil and gas production. We also use interest rate derivative instruments to minimize the impact of interest rate fluctuations. Depending on the regulations adopted by the CFTC, we could be required to post additional collateral with our dealer counterparties for our commitments and interest rate derivative transactions. Such a requirement could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price and interest rate uncertainty and to protect cash flows. Requirements to post collateral may cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or may require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability.

Our use of derivative financial instruments could result in material financial losses.

From time to time, we have sought to limit a portion of the potential adverse effects resulting from changes in commodity prices and interest rates by using derivative financial instruments and other hedging mechanisms. To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though they are closely monitored by management, our hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is economically imperfect, commodity prices or interest rates move unfavorably related to our physical or financial positions, or hedging policies and procedures are not followed.

Our operations rely on storage and transportation assets owned by third parties to satisfy their obligations. If storage capacity is inadequate or transportation is disrupted, our ability to satisfy our obligations may be hindered.

Our Utilities Group and Power Generation segment relies on pipeline companies and other owners of gas storage facilities to deliver natural gas to ratepayers, to supply our natural gas-fired plants and to hedge commodity costs. If storage capacity is inadequate or transportation is disrupted, our ability to satisfy our obligations may be hindered. As a result, we may be responsible for damages incurred by our counterparties, such as the additional cost of acquiring alternative supply at then-current market rates, or for penalties imposed by state regulatory authorities.

The failure to achieve or maintain compliance with existing or future governmental regulations or requirements could adversely affect our results of operations, financial position or liquidity. Additionally, the potentially high cost of complying with such requirements or addressing environmental liabilities could also adversely affect our results of operations, financial position or liquidity.

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

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

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

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

- Operational limitations imposed by environmental and other regulatory requirements.

- Interruptions to supply of fuel and other commodities used in generation and distribution. The Utilities Group purchases fuel from a number of suppliers. Our results of operations could be negatively impacted by disruptions in the delivery of fuel due to various factors, including but not limited to, transportation delays, labor relations, weather, and environmental regulations, which could limit the Utilities' ability to operate their facilities.

- Breakdown or failure of equipment or processes, including those operated by PacifiCorp at the Wyodak plant.

- Inability to recruit and retain skilled technical labor.

- Labor relations. Approximately 33% of our employees are represented by a total of six collective bargaining agreements.

- Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and gas that we sell to our retail and wholesale customers. If transmission is interrupted, our ability to sell or deliver product and satisfy our contractual obligations may be hindered.

- Operating hazards such as leaks, mechanical problems and accidents, including explosions, affecting our natural gas distribution system which could impact public safety, reliability and customer confidence.

Exploratory and development drilling are speculative activities that may not result in commercially productive reserves. Lack of drilling success could result in uneconomical investments and could have an adverse effect on our financial condition and results of operations.

Drilling activities are subject to many risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. There can be no assurance that new wells drilled by us or in which we have an interest will be productive or that we will recover all or any portion of our investment. Drilling for oil and gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating wells is often uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control, including economic conditions, mechanical problems, pressure or irregularities in formations, title problems, weather conditions, compliance with governmental rules and regulations and shortages in or delays in the delivery of equipment and services. Such equipment shortages and delays are caused by the high demand for rigs and other needed equipment by a large number of companies in active drilling basins. High activity in some basins may cause shortages of rigs and equipment in other basins. Our future drilling activities may not be successful. Lack of drilling success could have a material adverse effect on our financial condition and results of operations.

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

Threats of terrorism and catastrophic events that could result from terrorism, cyber-attacks, or individuals and/or groups attempting to disrupt our businesses, or the businesses of third parties, may impact our operations in unpredictable ways and could adversely affect our results of operations, financial position and liquidity.

- We are subject to the potentially adverse operating and financial effects of terrorist acts and threats, as well as cyber-attacks and other disruptive activities of individuals or groups. Our generation, transmission and distribution facilities, fuel storage facilities, information technology systems and other infrastructure facilities and systems and physical assets, could be direct targets of, or indirectly affected by, such activities. Terrorist acts or other similar events could harm our businesses by limiting their ability to generate, purchase or transmit power and by delaying their development and construction of new generating facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure our assets, and could adversely affect our operations by contributing to disruption of supplies and markets for natural gas, oil and other fuels. They could also impair our ability to raise capital by contributing to financial instability and lower economic activity.

- We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite our implementation of security measures, all of our technology systems are vulnerable to disability, failures or unauthorized access, including cyber-attacks. If our technology systems were to fail or be breached and be unable to recover in a timely way, we would be unable to fulfill critical business functions, and sensitive confidential and other data could be compromised, which could have material adverse effect on our financial results.

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- The implementation of security guidelines and measures and maintenance of insurance, to the extent available, addressing such activities could increase costs. These types of events could materially adversely affect our financial results. In addition, these types of events could require significant management attention and resources, and could adversely affect our reputation among customers and the public.

- A disruption of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources, could negatively impact our business. Because generation, transmission systems and natural gas pipelines are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the impact of an event on the interconnected system (such as severe weather or a generator or transmission facility outage, pipeline rupture, or a sudden significant increase or decrease in wind generation) within our system or within a neighboring system. Any such disruption could have a material impact on our financial results.

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

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

Federal and state laws concerning greenhouse gas regulations and air emissions may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain.

We own and operate regulated and non-regulated fossil-fuel generating plants in South Dakota, Wyoming, and Colorado. Recent developments under federal and state laws and regulations governing air emissions from fossil-fuel generating plants will likely result in more stringent emission limitations, which could have a material impact on our costs or operations. Various pending or final state and EPA regulations that will impact our facilities are also discussed in Item 1 of this Annual Report on Form 10-K under the caption "Environmental Matters."

On May 20, 2011, the EPA's Industrial and Commercial Boiler regulations became effective, which provide for hazardous air pollutant-related emission limits and monitoring requirements. The compliance deadline for this rule is March 21, 2014. Engineering evaluations have been completed and confirm the significant impact on our Neil Simpson I, Osage and Ben French facilities. We anticipate these units will be closed prior to the March 21, 2014 compliance deadline.

On December 16, 2011, the EPA signed the National Emission Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units, which became effective on February 16, 2012. Affected units will have three years from the rule effective date to be in compliance, with a pathway defined to apply for a one year extension due to certain circumstances. Certain requirements of that regulation could have significant impacts on the Neil Simpson II, Wygen I, Wygen II, Wygen III and Wyodak plants.

The GHG Tailoring Rule, implementing regulations of GHG for permitting purposes, became effective in June 2010. This rule will impact us in the event of a major modification at an existing facility or in the event of a new major source as defined by EPA regulations. Existing permitted facilities will see monitoring reporting requirements incorporated into their operating permits upon renewal. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could result in more stringent emissions control practices and technologies.

In 2010, the State of Colorado enacted House Bill 1365, the Colorado Clean Air, Clean Jobs Act, a coordinated utility plan to reduce air emissions from coal fired power plants and promoting the use of natural gas and other lower emitting resources. This act has a significant impact on our W.N. Clark facility and in October 2010, Colorado Electric filed testimony with the CPUC that recommended retirement of the W.N. Clark facility to comply with House Bill 1365 within three years of promulgation of the EPA's proposed Industrial and Commercial Boiler Hazardous Air Pollutant Regulations, or in the absence of such regulation, to retire the units by the end of 2017. In December 2010, the CPUC issued an order approving the closure of the W.N. Clark generation facility by December 31, 2013, and granted a presumption of need for replacement of the plant. Colorado Electric proposed to construct a third 88 MW natural gas-fired turbine at its Pueblo Airport Generation Station. Colorado Electric filed a Certificate of Public Convenience and Necessity in the first quarter of 2011 that provided for additional justification for the incremental 46 MW generation capacity. On December 14, 2011 an administrative law judge issued a recommendation to deny the CPCN. Subsequently Colorado Electric submitted an exception filing on which a ruling from the CPUC is expected by mid-2012.
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 on our company will depend upon many factors, including but not limited to the timing of implementation, the GHG sources that are regulated, the overall GHG emissions cap level, and the availability of technologies to control or reduce GHG emissions. If a "cap and trade" structure is implemented, the impact will depend on the degree to which offsets are allowed, the allocation of emission allowances to specific sources, and the effect of carbon regulation on natural gas and coal prices.
New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, and the closure of certain generating facilities. To the extent our regulated fossil-fuel generating plants are included in rate base; we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the power generated by those non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.
The 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. More stringent environmental regulations of emissions from coal-fueled power plants could increase the costs of using coal, thereby reducing demand for coal as a fuel source and the volume and price of our coal sales. Changes to regulations could make coal a less attractive fuel alternative in the planning and building of power plants in the future.

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

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

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

Our energy production, transmission and distribution activities involve numerous risks that may result in accidents and other catastrophic events. These events could result in impairment of our operations, additional costs and substantial loss to us.

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 effect on our financial position and results of operations. Particularly for our distribution lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the damages resulting from any such events could be great.

Increased risks of regulatory penalties could negatively impact our results of operations, financial position or liquidity.

Business activities in the energy sector are heavily regulated, primarily by agencies of the federal government. Agencies that historically sought voluntary compliance, or issued non-monetary sanctions, now employ mandatory civil penalty structures for regulatory violations. The Energy Policy Act of 2005 increased FERC's civil penalty authority for violation of FERC statutes, rules and orders. FERC may now impose penalties of $1.0 million per violation, per day. The CFTC, EPA, OSHA and MSHA also impose civil penalties to enforce compliance requirements relative to our business. In addition, FERC has delegated certain aspects of authority for enforcement of electric system reliability standards to the NERC, with similar penalty authority for violations. If a serious regulatory violation did occur, and penalties were imposed by FERC or another federal agency, this action could have a material adverse effect on our operations or our financial results.

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

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

- Energy Policy Act of 2005 and the repeal of the PUHCA;

- Industry consolidation;
- Consumer demands;
- Transmission constraints;
- Renewable resource supply requirements;
- Resistance to the siting of utility infrastructure or to the granting of right-of-ways;
- Technological advances; and

- Greater availability of natural gas-fired power generation, and other factors.

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

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

The recent global financial crisis made the credit markets less accessible and created a shortage of available credit. If a similar financial crisis occurs 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. A shortage of available credit at reasonable rates could have an adverse effect on our results of operations, financial position and liquidity.

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

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

The global financial situation has affected our counterparty credit risk which could have an adverse effect on our results of operations, financial position and liquidity.

As a consequence of the global financial markets, 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 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 credit-worthy counterparties through parent company guarantees, prepayments, letters of credit and other security agreements. Although we aggressively monitor and evaluate changes in our counterparties' credit quality and adjust the credit limits based upon such changes, our credit guidelines, controls and limits may not fully protect us from increasing counterparty credit risk. To the extent the economic conditions causes our credit exposure to contractual counterparties to increase materially, such increased exposure could have a material adverse effect on our results of operations, financial condition and liquidity.

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

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

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

Our issuer credit rating is "Baa3" (stable outlook) by Moody's; "BBB-" (stable outlook) by S&P; and "BBB-" (stable outlook) by Fitch. Reduction of our credit ratings could impair our ability to refinance or repay our existing debt and to complete new financings on acceptable terms, or at all. A downgrade could also result in counterparties requiring us to post additional collateral under existing or new contracts or trades. In addition, a ratings downgrade would increase our interest expense under some of our existing debt obligations, including borrowings under our credit facilities.

We rely on cash distributions from our subsidiaries to make and maintain dividends and debt payments. Our subsidiaries may not be able or permitted to make dividend payments or loan funds to us which could adversely affect our ability to meet our financial obligations or pay dividends to our shareholders.

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

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

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

Market performance or changes in other assumptions could require us to make significant unplanned contributions to our pension plans and other postretirement benefit plans. Increasing costs associated with our defined benefit retirement plans may adversely affect our results of operations, financial position or liquidity.

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

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

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

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

We have disclosed a material weakness in our internal control over financial reporting, and if we do not adequately remediate this weakness or if we have other material weaknesses or significant deficiencies in our internal control over financial reporting our business and financial condition may be adversely affected.

Our management is 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. As disclosed in Item 9A, management identified a material weakness in our internal control over financial reporting relating to accounting for income taxes. A material weakness is a deficiency, or combination of deficiencies, that result in a reasonable possibility that a material misstatement of a company's annual or interim financial statements will not be prevented or detected on a timely basis. As a result of this material weakness, our management concluded that our internal control over financial reporting and our disclosure controls and procedures were not effective as of December 31, 2011. Management is taking measures to remediate the material weakness and to enhance our internal controls over financial reporting. If our remedial measures are insufficient to address the material weakness, or if additional material weaknesses or significant deficiencies in our internal control occur in the future, our consolidated financial statements may contain material misstatements or other errors and we could be required to restate our financial results. If we cannot produce reliable financial reports, investors could lose confidence in our reported financial information, we may be unable to obtain additional financing, and our business and financial condition could be harmed.

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

We had approximately $353.4 million of goodwill on our consolidated balance sheet as of December 31, 2011. A substantial portion of the goodwill is related to the Aquila Transaction. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of our businesses, we may be forced to record a non-cash impairment charge, which would reduce our reported assets and net income. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including future business operating performance, changes in economic, regulatory, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more business segments, which may result in an impairment charge.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

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

ITEM 4. SPECIALIZED DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included in Exhibit 95 of this Annual Report.

PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol BKH. As of December 31, 2011, we had 4,620 common shareholders of record and approximately 25,800 beneficial owners, representing all 50 states, the District of Columbia and 7 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 26, 2012 meeting, our Board of Directors declared a quarterly dividend of $0.37 per share, equivalent to an annual dividend of $1.48 per share, marking 2012 as the 42nd 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, 2011

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$0.365	$0.365	$0.365	$0.365
Common stock prices				
High	$33.64	$34.85	$32.22	$34.47
Low	$29.76	$28.12	$25.83	$29.10

Year ended December 31, 2010

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$0.360	$0.360	$0.360	$0.360
Common stock prices				
High	$30.83	$34.49	$33.31	$33.42
Low	$25.65	$27.34	$27.79	$29.32

UNREGISTERED SECURITIES ISSUED DURING 2011

There were no unregistered securities sold during 2011, except as previously reported in our periodic and current reports to the SEC.

ISSUER PURCHASES OF EQUITY SECURITIES

The following table contains information about our acquisitions of equity securities during the three months ended December 31, 2011:

Period	Total Number of Shares Purchased *	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
October 1, 2011 –October 31, 2011	—	$—	—	—
November 1, 2011 –November 30, 2011	2,772	$31.27	—	—
December 1, 2011 –December 31, 2011	4,318	$32.75	—	—
Total	7,090	$32.17	—	—

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

ITEM 6. SELECTED FINANCIAL DATA

Years Ended December 31, (dollars in thousands, except per share amounts)	2011	(1) 2010	(1) 2009	(1) 2008	(1) 2007	(1)
Total Assets	$4,127,083	$3,711,509	$3,317,698	$3,379,889	$2,469,634	
Property, Plant and Equipment						
Total property, plant and equipment	$3,724,016	$3,353,509	$2,973,398	$2,703,117	$1,845,046	
Accumulated depreciation and depletion	(934,441)	(861,775)	(812,961)	(681,387)	(507,584)	
Capital Expenditures	$431,707	$496,990	$347,819	$1,304,330 (2)	$267,047	
Capitalization						
Current maturities	$2,473	$5,181	$35,245	$2,078	$130,326	
Notes payable	345,000	249,000	164,500	703,800	37,000	
Long-term debt, net of current maturities	1,280,409	1,186,050	1,015,912	501,252	503,301	
Common stock equity	1,209,336	1,100,270	1,084,837	1,050,536	975,022	
Total capitalization	$2,837,218	$2,540,501	$2,300,494	$2,257,666	$1,645,649	
Capitalization Ratios						
Short-term debt, including current maturities	12.2 %	10.0 %	8.7 %	31.3 %	10.2 %	
Long-term debt, net of current maturities	45.1 %	46.7 %	44.2 %	22.2 %	30.6 %	
Common stock equity	42.7 %	43.3 %	47.1 %	46.5 %	59.2 %	
Total	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	
Total Operating Revenues (3)	$1,272,188	$1,219,691	$1,198,712	$946,480	$481,002	
Net Income Available for Common Stock						
Utilities	$81,860	$74,563	$57,071	$43,904	$31,633	
Non-regulated Energy	866	10,189	1,581	(5) (42,384)	(6) 15,342	
Corporate expenses and intersegment eliminations	(42,361) (4)	(21,611) (4)	18,617	(4) (76,668)	(4) (7,878)	
Income (Loss) from Continuing Operations	40,365	63,141	77,269	(75,148)	39,097	
Income (loss) from discontinued operations, net of tax (7)	9,365	5,544	4,286	180,358	60,052	
Net loss attributable to non-controlling interest	—	—	—	(130)	(377)	
	$49,730	$68,685	$81,555	$105,080	$98,772	

Net income available for common stock

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SELECTED FINANCIAL DATA continued

Years Ended December 31, (dollars in thousands, except per share amounts)	2011 (1)	2010 (1)	2009 (1)	2008 (1)	2007 (1)
Dividends Paid on Common Stock	$59,202	$56,467	$55,151	$53,663	$50,300
Common Stock Data[(8)] (in thousands)					
Shares outstanding, average	39,864	38,916	38,614	38,193	37,024
Shares outstanding, average diluted	40,081	39,091	38,684	38,193	37,414
Shares outstanding, end of year	43,925	39,269	38,969	38,636	37,796
Earnings (Loss) Per Share of Common Stock (in dollars) [(8)]					
Basic earnings (loss) per average share -					
Continuing operations	$1.01	$1.62	$2.00	$(1.97)	$1.06
Discontinued operations	0.24	0.14	0.11	4.72	1.61
Non-controlling interest	—	—	—	—	(0.01)
Total	$1.25	$1.76	$2.11	$2.75	$2.66
Diluted earnings (loss) per average share -					
Continuing operations	$1.01	$1.62	$2.00	$(1.95)	$1.04
Discontinued operations	0.23	0.14	0.11	4.72	1.61
Non-controlling interest	—	—	—	—	(0.01)
Total	$1.24	$1.76	$2.11	$2.77	$2.64
Dividends Declared per Share	$1.46	$1.44	$1.42	$1.40	$1.37
Book Value Per Share, End of Year	$27.55	$28.02	$27.84	$27.19	$25.66
Return on Average Common Stock Equity (year-end)	4.3 %	6.3 %	7.6 %	10.4 %	11.2 %

SELECTED FINANCIAL DATA continued

Years ended December 31,	2011	2010	2009	2008	2007
Operating Statistics:					
Generating capacity (MW):					
Electric Utilities (owned generation) (9)	865	687	630	630	435
Electric Utilities (purchased capacity)	450	440	430	420	50
Power Generation (owned generation) (9) (10)	309	120	120	141	983
Total generating capacity	1,624	1,247	1,180	1,191	1,468
Electric Utilities:					
MWh sold:(1)					
Retail electric	4,590,800	4,532,191	4,403,459	3,532,402	2,552,290
Contracted wholesale	349,520	468,782	645,297	665,795	647,444
Wholesale off-system	1,788,005	1,749,524	1,692,191	1,551,273	942,045
Total MWh sold	6,728,325	6,750,497	6,740,947	5,749,470	4,141,779
Gas Utilities:(1) (11)					
Gas sold (Dth)	55,764,154	55,265,630	56,671,438	23,053,599	—
Transport volumes (Dth)	59,216,132	59,879,450	55,104,284	26,805,075	—
Oil and gas production sold (MMcfe)	11,762	11,300	12,463	13,534	14,627
Oil and gas reserves (MMcfe)	133,242	131,096	119,304	185,542	199,092
Tons of coal sold (thousands of tons)	5,692	5,931	5,955	6,017	5,049
Coal reserves (thousands of tons)	256,170	261,860	268,000	274,000	280,000
Discontinued Operations:					
Average daily marketing volumes:-					
Natural gas physical sales (MMBtu)	1,524,000	1,586,000	1,974,300	1,873,400	1,743,500
Crude oil physical sales (Bbls)	24,775	18,455	12,400	7,880	8,600
Coal physical sales (Tons)(12)	35,300	33,250	—	—	—
Power (MWh) (12)	265	—	—	—	—
Environmental (12)	—	—	—	—	—

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

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

(3) Revenues have been restated to reflect elimination of certain inter-company transactions with our rate regulated operations (see Note 1 of the Notes to the Consolidated Financial Statements of this Annual Report on Form 10-K).

(4) 2011, 2010 and 2008 include a $27.3 million, a $9.9 million and a $61.4 million, after-tax unrealized non-cash mark-to-market loss, respectively, related to certain interest rate swaps; while 2009 includes a $36.2 million after-tax unrealized non-cash mark-to-market gain related to certain interest rate swaps.

(5) Includes a $27.8 million after-tax non-cash 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.

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

(7)

Discontinued operations include the operations of the Energy Marketing segment in 2011, 2010, 2009, 2008 and 2007, and the assets sold in the IPP Transaction for 2009, 2008 and 2007.

(8) During November 2011, we issued 4.4 million shares of common stock and during February 2007, we issued 4.2 million shares of common stock, which diluted our earnings per share in subsequent periods.

(9) The PPA between Colorado Electric and Black Hills Colorado IPP is accounted for as a capital lease. This table reflects owned capacity by the Electric Utilities and Power Generation.

(10) 2007 includes 825 MW which have been reported as "Discontinued operations."

(11) Excludes Cheyenne Light.

(12) Coal marketing operations began in June 2010, and power and environmental marketing commenced late in the third quarter of 2010.

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

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

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

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

* In January 2012, we entered into a Stock Purchase Agreement to sell Enserco, our Energy Marketing segment, which resulted in the reporting of this segment as discontinued operations. The sale transaction is expected to be completed during the first quarter of 2012.

Our Utilities Group consists of our Electric and Gas utilities segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 201,500 customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light and its approximately 34,800 gas utility customers in Wyoming. Our Gas Utilities segment serves approximately 528,800 natural gas customers in Colorado, Iowa, Kansas and Nebraska. Our Non-regulated Energy Group engages in the production of natural gas, crude oil and coal, and the production of electric power through ownership of a portfolio of generating plants, the output energy and capacity of which is sold primarily under mid- and long-term wholesale contracts.

Industry Overview

The global economic crisis that commenced in late 2008 and continued through 2011 has reduced energy demand. Energy commodity prices, which were near historic highs in mid-2008, experienced dramatic declines in early 2009. While crude oil prices recovered notably from 2009 through 2011, natural gas prices have continued to decline. Domestic crude oil prices continued to be influenced by global factors, including foreign economic conditions (especially in China and Asia), the policies of OPEC and other large foreign oil producers, and political tensions and conflict in many regions.

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

Coal prices for both Western and Eastern markets continued to experience volatility in 2011 with multiple micro and macro influences impacting prices. NYMEX Capp (12000 Btu per pound) prices began the year at over $84.00, but finished the year around $70.00. Conversely, Powder River Basin (8800 Btu per pound) spot prices started the year at $13.00, then increased to more than $15.00 at the beginning of the summer, but ultimately settled back to $13.00 in late 2011.

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, add new assets such as transmission lines and renewable energy resources, and replace power generation facilities due to increasingly stringent state and federal emissions regulations. Utility companies generally are less impacted by economic downturns, but the severe recession and prolonged recovery affected demand for energy and the ability of customers to pay their utility bills, particularly in certain parts of the country. In 2010 and 2011, the United States economy appears to have initiated a slow recovery from the deep recession. For credit-worthy companies, equity and debt financings were successfully undertaken throughout 2010 and 2011.

The state utility regulatory climate in 2011 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.

Recent federal administrative and legislative actions have set the stage for an emphasis on increased regulation and government oversight of the energy industry. The energy marketplace and the Company continue to respond to the increased oversight and enforcement activity of FERC, and increased environmental and emissions reviews and mandates. The EPA passed rules in 2011 that will likely either require expensive upgrades or the closure of many older coal burning power plants. State legislatures also remained active on environmental issues in 2010 and 2011, with a majority of states now having adopted some form of renewable energy standard, including some in which we operate. In addition, several states have passed greenhouse gas emissions legislation, which places limits on the emissions of CO_2 and other greenhouse gases. These known and potential future administrative and legislative actions could have significant macroeconomic consequences, which may impact us, as the associated cost increases may cause a dramatic increase in consumer costs for products and services, including rates for electricity and other energy in the mid- to long-term.

The November 2010 elections caused a significant change in the domestic political environment, and a dramatic shift in domestic policy. The passage of the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, extends through 2012 lower tax rates introduced in 2001 and 2003, reduces the estate tax, extends unemployment benefits, reduces the Social Security portion of payroll taxes for employees, and extends bonus depreciation. A benefit to our investors, the bill extends through 2012 the lower capital gains tax rate introduced by the Jobs and Growth Tax Relief Reconciliation Act of 2003. Additionally, the bill extends the 100% bonus depreciation for business property acquired after September 8, 2010 and placed into service prior to January 1, 2012. This provision provided positive tax benefits for the Colorado Electric and Colorado IPP generation projects completed in 2011.

Over the last decade, the corporate structure of many energy companies underwent evaluation and change, in large part due to efforts to create additional shareholder value. Since before the economic crisis, a number of companies contemplated or implemented a realignment of business lines, reflecting a shift in long-term strategies. Some divested certain energy properties to focus on core businesses, such as exiting non-regulated power production or energy marketing, in favor of more stable utility operations. Others engaged in mergers and acquisitions with a goal to improve economies of scale and returns to investors. While mergers and acquisition activity in the utility industry essentially stopped in 2009 and 2010, several transactions were announced in late 2010, throughout 2011 and early 2012 which may signal a resumption of utility transactions. Private equity investors continued to play a role in the changing composition of energy ownership.

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

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

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

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

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

Business Strategy

We are a customer-focused integrated energy company. Our business is comprised of electric and natural gas utilities, power generation assets, and fuel assets which produce crude oil, natural gas and coal. Our focus on customers - whether they are utility customers or non-regulated generation - 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. Our emphasis on our utility businesses with diverse geographic and fuel mix, combined with a conservative approach to our non-regulated energy operations mitigates our overall corporate risk and enhances our ability to earn stronger returns for shareholders over the long-term. Despite challenging conditions in the capital markets over the past few years, we have demonstrated our ability to access the debt and equity markets, resulting in sufficient liquidity and solid cash flows. Consequently, our financial foundation is sound and capable of supporting an expansion of operations in both the near and long-term.

Our long-term strategy focuses on growing both our utility and non-regulated energy businesses, primarily by increasing our customer base and providing superior service to both utility and non-regulated energy customers.

In our natural gas and electric utilities, we intend to significantly grow our asset base to serve projected customer demand and to comply with environmental mandates in our existing utility service territories through expansion of infrastructure and construction of new rate-based power generation facilities. If the opportunity arises, we will pursue acquisitions of additional utility properties, primarily in the Great Plains and Rocky Mountain regions of the country. By maintaining our high customer service and reliability standards in a cost-efficient manner, our goal is to secure appropriate rate recovery to provide solid economic returns on our utility investments.

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

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

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

In January 2012, we entered into a definitive agreement to sell Enserco, our non-regulated Energy Marketing segment. This strategic divestiture should reduce our risk profile, improve our credit metrics and enhance our ability to produce more stable cash flows and earnings for our shareholders. With the completion of this transaction, we will strengthen the focus on our utilities, power generation and fuel production businesses. The proceeds from this divestiture will reduce our equity financing needs for planned growth projects.

Key Elements of our Business Strategy

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

Examples of our progress include the January 2008 completion of Wygen II to serve the customers of Cheyenne Light, the April 2010 completion of Wygen III to serve the customers of Black Hills Power, and the January 1, 2012 completion of a 180 MW gas-fired power plant to serve the customers of Colorado Electric. Existing legislation in Colorado will require the retirement of Colorado Electric's W.N. Clark plant by December 31, 2013. Additionally, EPA regulations covering hazardous air pollutants may necessitate the early retirement of several of our older coal-fired power plants, including Black Hills Power's Osage, Ben French and Neil Simpson I plants. We have recommended replacing these facilities with rate-based natural gas-fired power plants to be located in Cheyenne, WY.

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

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

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

- In states such as South Dakota and Wyoming that currently have no legislative mandate on the use of renewable energy, we have proactively integrated cost-effective renewable energy into our generation supply based upon our expectation that there will be mandatory renewable energy standards in the future. For example, under two 20-year PPAs we purchase a total of 60 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. To the extent practical, we intend to construct renewable generation resources as rate base assets, which will help mitigate the long-term customer rate impact of adding renewable energy supplies. For example, the CPUC approved a 29 MW wind turbine project in which we are permitted to rate base 50% ownership as part of our plan to meet Colorado's Renewable Energy Standard expected to be completed by the end of 2012; and

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

Expand utility operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages. For more than 129 years we have provided reliable utility services, delivering quality and value to our customers. Our tradition of accomplishment supports efforts to expand our utility operations into other markets, most likely in areas that permit us to take advantage of our intrinsic competitive advantages, such as baseload power generation, system reliability, superior customer service, community involvement and a relationship-based approach to regulatory matters. The 2005 acquisition of Cheyenne Light and the 2008 Aquila Transaction are examples of such expansion efforts. Utility operations also enhance other important business development opportunities, including gas transmission pipelines and storage infrastructure, which could promote other non-regulated energy operations. Utility operations can contribute substantially to the stability of our long-term cash flows, earnings and dividend policy.

We have a platform of systems and processes which are very scalable, which would simplify the integration of potential future utility acquisitions. Merger and acquisition activity in the utility industry has increased in the last year. We believe that impacts of the current recession may produce opportunities for healthy utility companies to acquire utility assets and operations of companies on 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 continue to need products, such as capacity, in order to reliably serve their customers. By providing these products under long-term contracts, we are able to help our customers meet their energy needs. Through this approach, we also believe we can earn more stable revenues and greater returns over the long term than we could by selling energy into more volatile spot markets. In addition, relationships that we've established with wholesale power customers have developed into other opportunities. MEAN and MDU, both wholesale power customers, are now also joint owners in two of our power plants, Wygen I and Wygen III, respectively.

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

Most of the energy and capacity from our non-regulated power facilities is sold under mid- and long-term contracts. When possible, we structure long-term contracts as tolling arrangements, whereby the contract counterparty assumes the fuel risk. Going forward, we will continue to focus on selling a majority of our non-regulated capacity and energy primarily to load-serving utilities under long-term agreements that have been reviewed or approved by state utility commissions. An example of this strategy is the 200 MW of combined-cycle gas-fired generation recently constructed by our non-regulated power generation subsidiary to serve our Colorado Electric utility subsidiary. The plant commenced operations on 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 was extended in 2011 through 2014. The Wygen I contract extended during 2009 now expires in 2022, and provides an option for Cheyenne Light to purchase and rate base a portion of Wygen I.

Apply 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 state-of-the-art mine-mouth coal-fired generating capacity, allowing 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.

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

- Through detailed reservoir analysis, apply proven technologies to our existing assets to maximize value;

- Participate in a limited number of selective and meaningful exploration prospects;

- Primarily focus on the Rocky Mountain region, where we can more easily integrate new opportunities with our existing crude oil and natural gas operations as well as our power generation activities. Specifically, we intend to focus our near term efforts on fully developing the substantial shale gas potential of our San Juan and Piceance Basin properties, continuing our participation in the Bakken oil shale play and participating in select oil exploration prospects with substantial upside opportunities;

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

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

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

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

Disruption in worldwide capital markets over the past few years has 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 and foreign governments, these events contributed to a general economic decline that materially and adversely impacted the broader financial and credit markets, and reduced the availability of debt and equity capital. Completion of the planned divestiture of Enserco, our Energy Marketing segment, will improve our credit metrics and reduce our overall risk profile.

Notwithstanding these adverse capital market conditions, we have completed several key financings during the period, including a net $119.6 million equity offering, a $200 million senior unsecured corporate bond offering, a $100 million one-year term loan which was subsequently negotiated to two-year term, and a $150 million one-year term loan.

Prospective Information

We expect to generate long-term growth through the expansion of integrated and diverse energy operations. We recognize that sustained growth requires continued capital deployment. Our diversified energy portfolio with an emphasis on regulated utilities provides growth opportunities, yet avoids concentrating business risk. We expect much of our growth in the next few years will come from major capital investments at our existing segments. During 2011, we were able to complete debt arrangements on favorable terms and in November 2011 settled the equity forward agreement initiated in 2010. We are confident in our ability to obtain additional financing to continue our growth plans. We remain focused on managing our operations cautiously and maintaining our overall liquidity to meet our operating, capital and financing needs, as well as execute our long-term strategic plan.

Utilities Group

Electric Utilities

Our Electric Utilities benefited from an increase in rates resulting from rate cases approved during 2010 and will benefit from a Colorado Electric rate case approval of $28.0 million in annual revenues which was effective January 1, 2012 upon commercial operation of a 180 MW gas-fired generation facility that now serves Colorado Electric customers. We believe that the addition of this plant to our utility rate base and the successful approval of our rate case will have a significant positive impact on our future financial results. As part of this rate case, the percentage of gross margin to be shared with customers for off-system sales at Colorado Electric was settled providing Colorado

Electric 25% of that gross margin, less certain operating costs, through 2013 and 10% thereafter. Additionally, on December 1, 2011, Cheyenne Light filed requests for electric and natural gas revenue increases of $8.5 million with the WPSC to recover investment in infrastructure and other costs.

Pursuant to prior approved resource plans, the Electric Utilities engaged in the following regulatory requests or construction activities during 2011:

- Cheyenne Light and Black Hill Power filed a joint CPCN requesting approval to construct a new 132 MW generating facility;

- Colorado Electric completed construction of a 180 MW generating facility, which was placed into commercial operation on January 1, 2012;

- Although CPUC issued an order approving the retirement of our W.N. Clark coal-fired generation facility in order to comply with the Colorado Clean Air-Clean Jobs Act for Colorado Electric, the CPUC has not yet approved plans proposed to replace the facility; and

- The CPUC approved construction of a 29 MW wind farm, of which Colorado Electric will own 50%, as part of our plan to meet Colorado's Renewable Energy Standards and Colorado Electric expects to file an energy resource plan to address additional renewable energy required to comply with Colorado's renewable energy standards in the second quarter of 2012.

The expiration and replacement of the PSCo PPA with Colorado Electric required additional capacity and energy needs of approximately 200 MW. The remaining capacity and energy needed was acquired through a competitive bidding process including other power producers. Our Power Generation segment was awarded the bid to provide 200 MW of capacity and energy to Colorado Electric through a 20-year PPA. The generating facilities commenced providing energy under this PPA on January 1, 2012. This PPA is being accounted for as a capital lease.

Gas Utilities

Our 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. We received approval in February 2011 for rate increases of $3.4 million at Iowa Gas for which interim rates were in place effective June 2010. We continually monitor our investments and costs of operations in all states to determine when additional rate cases or other rate filings will be necessary.

Non-regulated Energy Group

Power Generation

Our Power Generation segment was awarded the bid to provide 200 MW of power to our Colorado Electric subsidiary through a 20-year PPA. Construction costing approximately $261 million for a 200 MW combined cycle natural gas-fired power generation facility in Colorado was completed in December 2011 and this facility commenced commercial operation on January 1, 2012. We plan to continue evaluating opportunities to bid on the construction of generation resources, both new and existing, for other regional electric utilities for their energy and capacity needs.

Coal Mining

Production from the Coal Mining segment primarily serves mine-mouth generation plants and select regional customers with long-term fuel needs. Total annual production is estimated to be approximately 4.8 million tons in 2012, which is a decrease from 2011 primarily due to the termination of the PacifiCorp Dave Johnston contract which expired at the end of 2011. However, the termination of this contract should have a positive impact on earnings since the pricing of this contract was such that we were not recovering our costs during the latter periods of the agreement. Our primary strategy is to sell the majority of our coal production to on-site, mine-mouth generation facilities under long-term supply contracts. Historically our off-site sales have been to consumers within a close proximity to our mine. We have recently extended two smaller volume off-site sales contracts served by truck. There are some limitations in regards to transporting our lower-heat content coal; however, we continue to pursue new opportunities to market our product.

Oil and Gas

During 2011 we completed a strategic review of our oil and gas segment. We announced a revised strategy focused on proving up and developing the substantial Mancos formation shale gas potential of our existing properties in San Juan and Piceance Basins, complemented by limited, high potential oil exploration. We hired a new vice president and general manager to lead the business, who started in mid-December. During much of 2011, BHEP's mission was to identify future investment opportunities while conserving capital and strictly controlling costs. We completed three test wells in the Mancos formation drilling program in the San Juan and Piceance Basins with very promising results. Two of these wells resulted in 28.5 Bcfe of net reserves through the addition of two proved-developed producing wells and five proved-undeveloped locations. The third well was completed too late for reserves to be included in our year-end 2011 reserve study. We expect to book those reserves during 2012. We will continue our efforts into 2012 in anticipation of providing attractive oil and gas investment opportunities. We intend to commence a single rig drilling program in the San Juan Basin in mid-2012 targeting the Mancos shale with four wells drilled during the year.

Corporate

On November 1, 2011, we settled our equity forward offering of 4,413,519 shares providing approximately $119.6 million of cash proceeds. We also entered into a new $150 million term loan to fund our working capital needs and for other corporate purposes and extended our $100 million Term loan for two years. On February 1, 2012, we entered into a new 5 year $500 million Revolving Credit Facility at favorable terms.

As of December 31, 2011, 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, 2011, the mark-to-market value of these swaps was a liability of $96.0 million. In 2011, we recorded an unrealized mark-to-market after-tax loss of $27.3 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 2012 earnings as we record the associated unrealized mark-to-market gains or losses within our income statement.

Results of Operations

Executive Summary and Overview

	For the Years Ended			For the Years Ended		
	2011	2010	Increase (Decrease)	2010	2009	Increase (Decrease)
	(in thousands)					
Revenue [(a)]						
Utilities	$1,168,915	$1,120,721	$48,194	$1,120,721	$1,101,077	$19,644
Non-regulated Energy	178,372	162,355	16,017	162,355	159,749	2,606
Intercompany eliminations	(75,099)	(63,385)	(11,714)	(63,385)	(62,114)	(1,271)
	$1,272,188	$1,219,691	$52,497	$1,219,691	$1,198,712	$20,979
Income (loss) from continuing operations						
Electric Utilities	$47,691	$47,452	$239	$47,452	$32,699	$14,753
Gas Utilities	34,169	27,111	7,058	27,111	24,372	2,739
Utilities	81,860	74,563	7,297	74,563	57,071	17,492
Oil and Gas	(1,721)	357	(2,078)	357	(25,828)	26,185
Power Generation	3,011	2,151	860	2,151	20,661	(18,510)
Coal Mining	(424)	7,681	(8,105)	7,681	6,748	933
Non-regulated Energy	866	10,189	(9,323)	10,189	1,581	8,608
Corporate and Eliminations [(b)]	(42,361)	(21,611)	(20,750)	(21,611)	18,617	(40,228)
Income from continuing operations	40,365	63,141	(22,776)	63,141	77,269	(14,128)
Income (loss) from discontinued operations, net of tax [(c)]	9,365	5,544	3,821	5,544	4,286	1,258
Net income (loss)	$49,730	$68,685	$(18,955)	$68,685	$81,555	$(12,870)

(a) 2010 revenue has been restated to eliminate certain inter-company revenue previously not eliminated. This change did not have an impact on our gross margin or net income. See Note 1 of the Consolidated Financial Statements in this Annual Report on Form 10-K.

(b) Financial results of Enserco, our Energy Marketing segment, have been reclassified as discontinued operations in accordance with GAAP. When preparing this reclassification, certain indirect corporate costs and inter-segment interest expenses previously charged to our Energy Marketing segment could not be reclassified to discontinued operations and accordingly have been presented within Corporate. See Note 23 of the Consolidated Financial Statements in this Annual Report on Form 10-K.

(c) Income (loss) from discontinued operations, net of tax includes the activities of Enserco, our Energy Marketing segment, for 2011, 2010 and 2009 and the IPP Transaction for 2009. See Note 23 of the Consolidated Financial Statements in this Annual Report on Form 10-K.

In January 2012, we entered into a definitive agreement to sell Enserco, our Energy Marketing segment, which resulted in the reporting of this segment as discontinued operations. Information has been revised to remove information related to these operations that are now included in discontinued operations. Additionally, the following business group and segment information does not include intercompany eliminations and all amounts are presented on a pre-tax basis unless otherwise indicated.

2011 Compared to 2010

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

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

Business Group highlights for 2011 include:

Utilities Group

Highlights of the Utilities Group include the following:

- Our return on investments made in the Utilities Group was positively impacted by new and interim rates and tariffs implemented in five utility jurisdictions during 2010. Consequently, year-to-date revenues have been positively impacted for rates that were not in effect in the prior periods.

Utility	State	Effective Date	Annual Revenue Increase (in millions)
Black Hills Power	SD	4/2010	$ 15.2
Black Hills Power	WY	6/2010	$ 3.1
Colorado Electric	CO	8/2010	$ 17.9
Nebraska Gas	NE	3/2010	$ 8.3
Iowa Gas	IA	6/2010	$ 3.4
			$ 47.9

- Construction of gas-fired generation to serve Colorado Electric customers was completed and the plant was placed in service on January 1, 2012. The 180 MW generation project cost approximately $230 million;

- On April 28, 2011, Colorado Electric filed a request with the CPUC for a revenue increase of $40.2 million to recover costs and a return associated with the 180 MW generation project and other utility infrastructure assets and expenses, including PPA costs associated with the 200 MW Colorado IPP generation facility. On December 22, 2011, the CPUC issued an order approving an annual base rate increase of $10.5 million with a rate of return ranging from 9.8% to 10.2% with a capital structure of 49.1% equity and 50.9% debt. The CPUC approved additional costs to be recovered through rate adjustment mechanisms of approximately $17.5 million. New rates were effective January 1, 2012;

- On December 1, 2011, Cheyenne Light filed requests for electric and natural gas revenue increases with the WPSC to recover investments in infrastructure and other costs. Cheyenne Light is seeking a $5.9 million increase in annual electric revenue and a $2.6 million increase in annual natural gas revenue;

- On November 1, 2011, Cheyenne Light and Black Hills Power filed a joint request with the WPSC for a certificate of public convenience and necessity to construct and operate a new $237 million natural gas-fired electric generation facility and related gas and electric transmission in Cheyenne, WY. The proposed facility will include construction of one simple-cycle, 37 MW combustion turbine that will be wholly owned by Cheyenne Light and one combined-cycle, 95 MW unit that will be jointly owned by Cheyenne Light and Black Hills Power. Cheyenne Light will own 40 MW and Black Hills Power will own 55 MW of the combined cycle unit. Pending WPSC approval, commercial operation would commence in 2014. A hearing with the WPSC is scheduled in July 2012;

- In June 2011, the SDPUC approved an Environmental Improvement Adjustment tariff for Black Hills Power. The Environmental Improvement Adjustment, which was implemented to recover Black Hills Power's investment of $25 million for pollution control equipment at the PacifiCorp-operated Wyodak plant, went into effect on June 1, 2011 with an annual revenue increase of $3.1 million;

- On August 12, 2011, Colorado Electric received approval from the CPUC to rate base 50% ownership in a 29 MW wind turbine project as part of its plan to meet Colorado's Renewable Energy Standard. The CPUC authorized us to conduct a competitive solicitation for ownership of the other 50% of the project under which a partner was selected in December 2011 and a Renewable Energy Purchase Agreement and Participation agreement was executed on December 22, 2011. Colorado Electric's share of this project is expected to cost approximately $26.5 million. It is expected to begin serving Colorado Electric customers no later than December 31, 2012; and

- On March 14, 2011, Colorado Electric filed a request for a CPCN to construct a third utility-owned 88 MW natural gas-fired turbine with an approximate cost of $102.0 million, excluding transmission. This CPCN request was filed in accordance with a December 2010 CPUC order. This order approved the retirement of the W.N. Clark coal-fired power plant under the Colorado Clean Air-Clean Jobs Act and granted a presumption of need for a portion of a third utility-owned turbine at the Pueblo Airport Generation Station. A settlement with some of the intervenors was reached and a settlement hearing occurred on October 25, 2011. On December 14, 2011, an administrative law judge issued a recommendation to deny Colorado Electric's request and the terms of the settlement agreement. Colorado Electric submitted an exception filing on January 10, 2012, and an initial decision from the CPUC is expected in mid-2012.

Non-regulated Energy Group

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

- In January 2012, we entered into a definitive agreement to sell the outstanding stock of Enserco Energy, Inc., our Energy Marketing segment. Net cash proceeds are expected to total approximately $160 million to $170 million, subject to working capital and other closing adjustments. The sale is subject to customary regulatory approvals and is expected to close in the first quarter of 2012. The activities of the Energy Marketing segment have been reclassified to discontinued operations;

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

- Three test wells as part of our Oil and Gas segment's Mancos shale horizontal drilling program in the San Juan and Piceance Basins have been completed and are on production. Production test results and reserve estimates are encouraging; and

- In January 2011, we sold our ownership interests in the partnerships that owned the Idaho generating facilities for $0.8 million and recorded a gain of $0.8 million.

Corporate

Activities at Corporate include the following:

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

- In November 2011, the Equity Forward Agreements were settled by issuing 4,413,519 shares of Black Hills Corporation common stock in return for net cash proceeds of $119.6 million;
- In September 2011, we extended our $100.0 million term loan under the existing terms for two years; and
- In June 2011, we entered into a $150 million one year, unsecured, single draw, term loan. The cost of borrowing under this term loan is based on a spread of 1.25% over LIBOR.

2010 Compared to 2009

Income from continuing operations was $63.1 million, or $1.62 per share, in 2010 compared to income from continuing operations of $77.3 million, or $2.00 per share for 2009. The 2010 income from continuing operations includes a gain on sale of $5.8 million after-tax of a 23% ownership interest in the Wygen III plant and assets sold by Nebraska Gas after the annexation of a service area, and a $9.9 million unrealized after-tax non-cash mark-to-market loss on certain interest rate swaps. 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 unrealized after-tax non-cash mark-to-market gain on certain interest rate swaps; and a $27.8 million after-tax loss of a non-cash ceiling test impairment at our Oil and Gas segment.

Net income was $68.7 million, or $1.76 per share, in 2010 compared to $81.6 million, or $2.11 per share, in 2009. Enserco, our Energy Marketing segment, has been reclassified and is included in income from discontinued operations in 2010 and 2009 with 2009 also including $2.8 million after-tax income from discontinued operations related to the operations sold in the IPP Transaction.

Highlights of our business groups are as follows:

Utilities Group

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

- Our return on investments made in the Utilities Group was positively impacted by new and interim rates and tariffs implemented in five utility jurisdictions during 2010. Consequently, year-to-date revenues were positively impacted for rates that were not in effect in the prior periods.

Utility	State	Effective Date	Annual Revenue Increase (in millions)	
Black Hills Power	SD	4/2010	$	15.2
Black Hills Power	WY	6/2010	$	3.1
Colorado Electric	CO	8/2010	$	17.9
Nebraska Gas	NE	3/2010	$	8.3
Iowa Gas	IA	6/2010	$	3.4
			$	47.9

- Construction of a 180 MW gas-fired generation to serve Colorado Electric customers moved forward to start providing energy by January 1, 2012. Expenditures were approximately $164.4 million through December 31, 2010;

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

- On October 1, 2010, Black Hills Power suspended the operations of its 62 year old, 34.5 MW coal-fired Osage Power Plant located in Osage, Wyoming. We now have more economical power supply alternatives available to provide for present customer energy demands; however, the plant's operating permits have been retained so that full operations can be restored if needed;

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Our Electric Utilities reached agreement with the DOE for smart grid funding through matching grants totaling $20.7 million, made available through the American Recovery and Reinvestment Act of 2009. As of December 31, 2010, we have completed 100% of the installations related to these meters;

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

- In December 2010, Colorado Electric received a final order from the CPUC regarding its plan to comply with the Colorado Clean Air, Clean Jobs Act. The order approved the retirement of the utility's 42 MW W.N. Clark coal-fired generation facility and granted a presumption of need for replacement of the plant. The utility proposed to construct a third 88 MW natural gas-fired turbine at the site of our Pueblo Airport Generation Station.

Non-Regulated Energy Group

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

- Construction of a 200 MW gas-fired generation at Black Hills Colorado IPP to serve a 20-year PPA with Colorado Electric moved forward to start providing energy by January 1, 2012. Expenditures on the project were $162.6 million through December 31, 2010;

- The first quarter of 2009 included a $16.9 million after-tax gain at our Power Generation segment on the sale to MEAN of a 23.5% ownership interest in the Wygen I power generation facility; and

- The first quarter of 2009 included a $27.8 million after-tax non-cash ceiling test impairment charge due to a write-down in value of our natural gas and crude oil properties resulting from low quarter-end prices for the commodities at our Oil and Gas segment.

Corporate

Activities of Corporate include the following:

- We recognized a non-cash unrealized mark-to-market loss related to certain interest rate swaps of $15.2 million in 2010 compared to a $55.7 million unrealized gain on these swaps for the same period in 2009;

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

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

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

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

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

Operating Results

A discussion of operating results from our business segments follows.

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Utilities Group

Electric Utilities

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

	2011	2010	2009
Revenue - electric	$577,513	$532,423	$485,152
Revenue - Cheyenne Light gas	36,818	37,591	35,613
Total revenue	614,331	570,014	520,765
Fuel and purchased power - electric	288,354	269,747	260,150
Purchased gas - Cheyenne Light	21,998	23,064	20,859
Total fuel and purchased power	310,352	292,811	281,009
Gross margin - electric	289,159	262,676	225,002
Gross margin - Cheyenne Light gas	14,820	14,527	14,754
Total gross margin	303,979	277,203	239,756
Operations and maintenance	142,815	136,873	125,150
Gain on sale of operating asset	(768)	(6,238)	—
Depreciation and amortization	52,475	47,276	43,638
Total operating expenses	194,522	177,911	168,788
Operating income	109,457	99,292	70,968
Interest expense, net	38,976	37,043	33,012
Other income, net	(481)	(3,215)	(7,869)
Income tax expense	23,271	18,012	13,126
Income from continuing operations	$47,691	$47,452	$32,699

	2011	2010	2009
Regulated power plant fleet availability:			
Coal-fired plants [(a)]	91.3%	93.9%	92.1%
Other plants	96.4%	96.2%	96.9%
Total availability	93.1%	94.8%	94.0%

(a) 2011 reflects a major overhaul and an unplanned outage at the PacifiCorp-operated Wyodak plant.

2011 Compared to 2010

Gross margin increased $26.8 million primarily due to a $17.1 million increase related to rate adjustments that include a return on significant capital investments, $1.3 million increase from the impact of a new Environmental Improvement Cost Recovery rider at Black Hills Power that went into effect on June 1, 2011, $3.1 million increase in retail MWh sold, $6.9 million increase for transmission cost adjustments for retail and wholesale customers, and $0.3 million increase in off-system sales impacted by recognition of $0.7 million of deferred margins upon settlement of Colorado Electric's power marketing sharing mechanism with the CPUC.

Operations and maintenance increased $5.9 million primarily due to higher allocation of corporate costs driven by an increased asset base in the Electric Utilities; additional costs associated with Wygen III, which commenced commercial operation on April 1, 2010, and approximately $1.1 million of deferred power marketing costs that were recognized in 2011 upon settlement of an off-system sales sharing mechanism with the CPUC, partially offset by suspension of the Osage plant.

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

Depreciation and amortization increased $5.2 million primarily due to a higher asset base including additional depreciation associated with Wygen III, which began commercial operation on April 1, 2010.

Interest expense, net increased $1.9 million due to higher borrowings related to recent capital projects, partially offset by increased AFUDC-borrowed and interest income. AFUDC-borrowed increased $5.1 million at Colorado Electric due to construction of the Pueblo Airport Generating Station, offset by a decrease in AFUDC-borrowed at Black Hills Power of $1.8 million due to the commencement of commercial operations of Wygen III.

Other income, net decreased $2.7 million primarily due to lower AFUDC-equity of $2.0 million, which decreased upon the placement of Wygen III into commercial operations on April 1, 2010.

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

2010 Compared to 2009

Gross margin increased $37.4 million primarily due to a $25.5 million increase related to the impact of the outcome of the Black Hills Power and Colorado Electric rate cases, an increase of $3.4 million for updated transmission cost adjustments at Colorado Electric, an increase of $4.6 million in off-system sales margin as a result of a change in the methodology used at Black Hills Power to allocate the cost of renewable resources and firm purchases, and increased intercompany revenues of $4.3 million due to a new shared services agreement related to resources utilized by affiliated entities.

Operations and maintenance increased $11.7 million primarily due to additional costs of $6.8 million associated with the operations of Wygen III, which commenced commercial operation on April 1, 2010, increased intercompany costs of $1.6 million related to a new shared services agreement, and costs of $2.0 million associated with a major overhaul at the Ben French plant.

Gain on sale of operating assets: A gain on sale was recognized in 2010 on the sale of a 23% ownership interest in the Wygen III generating facility to the City of Gillette.

Depreciation and amortization costs increased $3.6 million primarily due to the addition of the Wygen III plant placed into service on April 1, 2010.

Interest expense, net increased $4.0 million primarily due to higher net interest expense of $8.6 million compared to the same period in the prior year due to debt incurred for plant construction and as a result of higher rates associated with long-term financings in 2010 compared to rates on short-term debt held in 2009, partially offset by an increase in AFUDC-borrowed of $4.6 million. AFUDC-borrowed increased $6.7 million at Colorado Electric for the plant construction, offset by a decrease in AFUDC-borrowed at Black Hills Power of $2.1 million due to the commencement of commercial operations of Wygen III.

Other income, net decreased $4.7 million primarily due to lower AFUDC-equity of $3.1 million, which decreased upon the placement of Wygen III into commercial operation. Additionally, 2009 included a gain of $1.1 million from the sale of SO_2 emission credits.

Income tax expense: The effective tax rate decreased primarily as a result of a $2.2 million tax benefit for a rate case settlement related to expensing certain items that had been capitalized for income tax purposes, partially offset by lower benefit from AFUDC-equity which decreased upon commercial operations of Wygen III.

Gas Utilities

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

	2011	2010	2009
Revenue:			
Natural gas - regulated	$526,972	$520,691	$553,576
Other - non-regulated	27,612	30,016	26,736
Total revenue	554,584	550,707	580,312
Cost of sales:			
Natural gas - regulated	317,257	316,546	356,623
Other - non-regulated	14,704	17,171	15,093
Total cost of sales	331,961	333,717	371,716
Gross margin:			
Natural gas - regulated	209,715	204,145	196,953
Other non-regulated	12,908	12,845	11,643
Total gross margin	222,623	216,990	208,596
Operations and maintenance	121,980	125,447	123,296
Gain on sale of operating assets	—	(2,683)	—
Depreciation and amortization	24,307	25,258	30,090
Total operating expenses	146,287	148,022	153,386
Operating income	76,336	68,968	55,210
Interest expense, net	25,976	27,455	17,100
Other expense (income), net	(217)	(47)	285
Income tax expense	16,408	14,449	13,453
Income from continuing operations	$34,169	$27,111	$24,372

2011 Compared to 2010

Gross margin increased $5.6 million primarily due to an increase in rates from rate case settlements.

Operations and maintenance decreased $3.5 million primarily due to decreases in employee benefit costs, workers compensation insurance, lower corporate allocations and litigation-related expenses.

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

Depreciation and amortization decreased $1.0 million primarily due to certain assets that became fully depreciated during 2010, partially offset by capital expenditures during 2011.

Interest expense, net decreased $1.5 million primarily due to lower inter-company debt and allocation of debt service within the assigned capital structure.

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

Income tax expense: The effective tax rate for 2011 decreased compared to the same period in the prior year primarily as a result of a true-up adjustment related to the 2010 tax filing and a flow-through tax adjustment at Iowa Gas.

2010 Compared to 2009

Gross margin increased $8.4 million primarily due to new and interim rates at Colorado Gas, Nebraska Gas and Iowa Gas, and an approved Gas System Reliability Surcharge at Kansas Gas, which were not effective for a full year in 2009, partially offset by lower volumes as a result of milder weather in 2010.

Operations and maintenance increased $2.2 million primarily due to increases in employee benefit costs, workers compensation insurance and litigation-related expenses.

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

Depreciation and amortization decreased $4.8 million primarily due to assets becoming fully depreciated during 2009 and 2010.

Interest expense, net increased $10.4 million primarily due to higher interest rates within the assigned capital structure.

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

Income tax expense: The effective tax rate for 2010 was comparable to the effective tax rate in the prior year.

Non-regulated Energy Group

Oil and Gas

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

	2011	2010	2009
Revenue	$79,808	$74,164	$70,684
Operations and maintenance	41,380	39,299	40,224
Depreciation, depletion and amortization	35,690	30,283	29,680
Impairment of long-lived assets	—	—	43,301
Total operating expenses	77,070	69,582	113,205
Operating income (loss)	2,738	4,582	(42,521)
Interest expense, net	5,894	5,372	4,673
Other (income) expense, net	216	(722)	(350)
Income tax (benefit) expense	(1,651)	(425)	(21,016)
Income (loss) from continuing operations	$(1,721)	$357	$(25,828)

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

Crude Oil and Natural Gas Production	2011	2010	2009
Bbls of oil sold	451,823	375,646	366,000
Mcfe of natural gas sold	9,051,393	9,046,493	10,266,900
Mcf equivalent sales	11,762,331	11,300,369	12,462,900

Average Price Received (a)	2011	2010	2009
Gas/Mcf(b)	$4.29	$4.85	$4.71
Oil/Bbl	$79.74	$75.59	$59.19

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(a) Net of hedge settlement gains/losses
(b) Exclusive of gas liquids

	2011	2010	2009
Depletion expense/Mcfe*	$2.76	$2.36	$2.16

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* The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented. The increased depletion rate in 2011 is primarily driven by the high cost of wells associated with our drilling activities in the Bakken shale formation. 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 certain annual average operating expenses per Mcfe at December 31:

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

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

	2009			
	LOE	Gathering Compression and Processing	Production Taxes	Total
San Juan	$1.27	$0.28	$0.47	$2.02
Piceance	1.06	0.41	0.25	1.72
Powder River	1.36	—	0.72	2.08
Williston	0.67	—	0.88	1.55
All other properties	1.08	0.04	0.25	1.37
Total	$1.22	$0.18	$0.46	$1.86

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:

	2011	2010	2009
Bbls of oil (in thousands)	6,223	5,940	5,274
MMcf of natural gas	95,904	95,456	87,660
Total MMcfe	133,242	131,096	119,304

Reserves are based on reports prepared by an independent consulting and engineering firm. The reports were prepared by CG&A. Reserves were determined using SEC-defined product prices. Such reserve estimates are inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The current estimate takes into account 2011 production of approximately 11.2 Bcfe, additions from extensions, discoveries and acquisitions of 35.2 Bcfe and negative revisions to previous estimates of 21.3 Bcfe, primarily due to reserve aging.

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

	2011		2010		2009	
	Oil	Gas	Oil	Gas	Oil	Gas
NYMEX prices	$96.19	$4.12	$79.43	$4.38	$61.18	$3.87
Well-head reserve prices	$88.49	$3.59	$70.82	$3.45	$53.59	$2.52

2011 Compared to 2010

Revenue increased $5.6 million primarily due to a 5% increase in the annual average hedged price received for crude oil and a 20% increase in crude oil production, partially offset by a 12% decrease in the annual average hedged price received for natural gas. The increase in crude oil production is primarily due to production from new wells in our ongoing Bakken drilling program. Natural gas production increased slightly as production from new wells has more than offset natural production declines in existing producing properties, that followed reduced capital deployment during 2010 and 2009.

Operations and maintenance increased $2.1 million primarily as a result of increased production taxes from higher revenue.

Depreciation, depletion and amortization increased $5.4 million primarily due to a higher depletion rate per Mcfe. The increasing depletion rate is primarily driven by the high cost of wells associated with our drilling activities in the Bakken shale formation.

Interest expense, net increased $0.5 million primarily due to increased debt used to finance additional capital expenditures and higher interest rates.

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

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

2010 Compared to 2009

Revenue increased $3.5 million primarily due to a 28% and 3% increase in the annual average hedged price of crude oil and gas, respectively, and a 3% increase in crude oil production, partially offset by a decrease of 12% in gas production. The increase in crude oil production is primarily due to production of new wells in our ongoing Bakken drilling program. The decrease in natural gas production was largely driven by natural production declines from producing properties and reduced capital deployment during 2010 and 2009.

Operations and maintenance expenses decreased $0.9 million primarily as a result of cost containment efforts.

Impairment of long-lived assets: A $43.3 million 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 crude 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.

Depreciation, depletion and amortization expense increased $0.6 million primarily due to an increased depletion rate per Mcfe resulting from increased investment in our ongoing Bakken formation drilling program, partially offset by a decrease in volumes sold.

Interest expense, net increased primarily due to increased interest rates.

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

Income tax (benefit) expense: The effective tax rate in 2010 includes a tax benefit related to percentage depletion and a $0.4 million re-measurement of a previously recorded uncertain tax position prompted by a settlement with the IRS Appeals Division. The tax position related to tax depreciation method changes. The effective tax rate in 2009 was impacted by a tax benefit of $3.8 million related to a positive adjustment of a previously recorded tax position.

Power Generation

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

	2011	2010	2009
Revenue	$31,672	$30,349	$30,575
Operations and maintenance	16,538	16,210	12,631
Depreciation and amortization	4,199	4,466	3,860
Gain on sale of operating assets	—	—	(25,971)
Total operating expenses	20,737	20,676	(9,480)
Operating income	10,935	9,673	40,055
Interest expense, net	7,374	8,110	9,388
Other (income) expense, net	(1,094)	(854)	(1,091)
Income tax expense	1,644	266	11,097
Income from continuing operations	$3,011	$2,151	$20,661

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

	2011	2010	2009
Independent power capacity:			
MW of independent power capacity in service	309	120	120
Contracted fleet plant availability:			
Gas-fired plants	98.4%	99.9%	92.0%
Coal-fired plants	100.0%	98.5%	96.1%
Total	99.0%	99.1%	94.4%

2011 Compared to 2010

Revenue increased $1.3 million primarily due to higher sales from Wygen I, which incurred a forced outage and major overhaul in the prior year.

Operations and maintenance increased $0.3 million primarily due to higher costs associated with the Black Hills Colorado IPP as employees prepared for operations of the facilities. This was partially offset by lower operating costs associated with Wygen I which incurred a forced outage and major overhaul in the prior year.

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

Interest expense, net decreased $0.7 million primarily due to capitalized interest related to the generation construction at Colorado IPP and increased inter-company interest income at Black Hills Wyoming.

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

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

2010 Compared to 2009

Revenue in 2010 was comparable to the same period in the prior year.

Operations and maintenance increased $3.6 million primarily due to maintenance costs for a major overhaul and extended outage at Wygen I and increased transmission costs.

Gain on sale of operating assets: The gain on sale of operating assets in 2009 represents the sale of a 23.5% ownership interest in the Wygen I power generation facility;

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

Interest expense, net decreased $1.3 million primarily due to a decrease in debt from an intercompany debt restructuring partially offset by interest expense associated with the $120 million project financing at Black Hills Wyoming.

Other (income) expenses, net in 2010 was comparable to other income in 2009.

Income tax expense: The effective tax rate for 2010 decreased compared to 2009 primarily due to the effect of research and development tax credits in 2010.

Coal Mining

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

	2011	2010	2009
Revenue	$66,892	$57,842	$58,490
Operations and maintenance	56,617	34,028	40,312
Depreciation, depletion and amortization	18,670	19,083	13,123
Total operating expenses	75,287	53,111	53,435
Operating income (loss)	(8,395)	4,731	5,055
Interest income, net	(3,888)	(3,180)	(1,452)
Other income, net	(2,192)	(2,149)	(3,475)
Income tax expense	(1,891)	2,379	3,234
Income (loss) from continuing operations	$(424)	$7,681	$6,748

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

	2011	2010	2009
Tons of coal sold	5,692	5,931	5,955
Cubic yards of overburden moved	14,735	15,679	14,539
Coal reserves at year-end	256,170	261,860	268,000

2011 Compared to 2010

Revenue increased $9.1 million primarily due to a 21% increase in average price per ton partially offset by a 4% decrease in volumes sold as a result of overhauls and unplanned outages at the PacifiCorp operated Wyodak plant. The higher average sales price reflects the impact of price escalators and adjustments in certain of our sales contracts. In 2011, approximately 40% of our coal production was sold under contracts that include price adjustments based on actual mining costs. Most of our remaining production is sold under contracts where the sales price may escalate based on published indices. These escalators have not kept up with actual mining cost increases, reducing coal mine operating income and negatively impacting 2011 results. One of these contracts, representing 29% of the tons sold during 2011, was terminated at December 31, 2011.

Operations and maintenance increases of $22.6 million reflect longer haul distances and higher overburden stripping costs in the current phase of our mining. Additionally, we experienced higher costs associated with drilling and blasting, equipment maintenance, clay parting removal, fuel, staffing levels for our train load-out facility and weather conditions. As noted above, a portion of our production is sold under contracts that have price escalators based on published indices. These escalators have not kept up with actual mining cost increases, reducing coal mine operating income and negatively impacting 2011 results. One of these contracts, representing 29% of the tons sold during 2011, was terminated at December 31, 2011. Previous periods also include the capitalization of certain costs associated with mine infrastructure, including our in-pit conveyor system used to transport coal to mine-mouth generation facilities.

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

Interest income, net increased $0.7 million primarily due to increased lending to affiliates.

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

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

2010 Compared to 2009

Revenue decreased $0.6 million primarily due to a lower price on coal contracts. There was a slight decrease in volumes sold primarily due to customer plant outages and lower demand for coal, offset by sales to Wygen III, which commenced commercial operations in April 2010.

Operations and maintenance decreased $6.3 million. During 2010, the company received approval from Wyoming's Department of Environmental Quality for a revised post-mining topography plan. The new plan includes a more efficient method of conducting final reclamation of the mine site by re-assessing the handling of overburden. Accordingly, a higher percentage of our overburden removal activities also qualify as reclamation backfill activities. This change resulted in lower operations expense and a related increase in depletion of reclamation costs. Cubic yards of overburden moved increased 8%.

Depreciation, depletion and amortization increased $6.0 million primarily due to an increase in depletion of reclamation costs as discussed in Operations and maintenance.

Interest income, net increased $1.7 million primarily due to increased lending to affiliates at higher interest rates.

Other income, net decreased $1.3 million primarily due to lower rental income related to the Wygen III site lease. The site lease was entered into in the third quarter of 2009 with billings back to March 2008.

Income taxes: The effective tax rate decreased primarily due to an increased tax benefit generated by percentage depletion.

Corporate

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

2011 Compared to 2010

- We incurred a $42.0 million unrealized mark-to-market loss in 2011 related to certain interest rate swaps that are no longer designated as hedges for accounting purposes compared to a $15.2 million unrealized mark-to-market loss in 2010; and

- Corporate was allocated costs of $3.4 million originally allocated to our Energy Marketing segment in 2011 which could not be included in discontinued operations compared to $3.5 million in 2010.

2010 Compared to 2009

- We incurred a $15.2 million unrealized mark-to-market loss in 2010 related to certain interest rate swaps that are no longer designated as hedges for accounting purposes compared to an unrealized mark-to-market gain of $55.7 million in 2009;

- Net interest expense increased $1.4 million primarily due to interest settlements of the de-designated interest rate swaps;
- The effective tax rate for 2010 was favorably impacted due to a re-measurement of a previously recorded uncertain tax position prompted by a settlement agreement with the IRS relating primarily to depreciation method changes; and
- Corporate was allocated costs of $3.5 million originally allocated to our Energy Marketing segment in 2010 which could not be included in discontinued operations compared to $3.8 million in 2009.

Discontinued Operations

In January 2012, we entered into a definitive agreement to sell Enserco, which resulted in our non-regulated Energy Marketing segment being reported as discontinued operations. We expect the transaction to close in the first quarter of 2012. For comparative purposes, all prior results of our Energy Marketing segment presented have been restated to reflect the reclassification of this segment to discontinued operations on a consistent basis.

Gross margins by commodity:	For the Years Ended December 31,					
	Natural Gas	Crude Oil	Coal	Power	Environmental	Total
2011						
Realized	$21,416	$22,793	$1,148	$(1,271)	$(13)	$44,073
Unrealized	(10,268)	(2,756)	3,298	6,664	90	(2,972)
Total	$11,148	$20,037	$4,446	$5,393	$77	$41,101
	Natural Gas	Crude Oil	Coal[(a)]	Power[(a)]	Environmental[(a)]	Total
2010						
Realized	$24,536	$8,888	$1,541	$(2,467)	$—	$32,498
Unrealized	(6,777)	1,663	2,012	(1,397)	—	(4,499)
Total	$17,759	$10,551	$3,553	$(3,864)	$—	$27,999
	Natural Gas	Crude Oil	Coal[(a)]	Power[(a)]	Environmental[(a)]	Total
2009						
Realized	$30,134	$11,278	$—	$—	$—	$41,412
Unrealized	(19,777)	(8,254)	—	—	—	(28,031)
Total	$10,357	$3,024	$—	$—	$—	$13,381

(a) Activity of Coal marketing commenced June 1, 2010 and Power and Environmental marketing commenced late in the third quarter of 2010.

2011 Compared to 2010

Income from discontinued operations was $9.4 million in 2011 compared to $5.5 million for the same period in the prior year. These results were driven by increased realized margins for crude oil of $11.4 million and unrealized margins for power marketing of $8.1 million, partially offset by lower unrealized margins for natural gas and crude oil of $3.5 million and $4.5 million, respectively. The increase in power marketing was due to a long-term supply contract while the decrease in natural gas marketing was a result of lower natural gas prices. These margin increases were partially offset by a higher provision for incentive compensation related to the increased margins and increased employee costs associated with employee additions required to market the new commodities added in 2010.

2010 Compared to 2009

Income from discontinued operations was $5.5 million in 2010 compared to $4.3 million for the same period in the prior year. Gross margin increased $14.6 million due to higher incremental margins in natural gas and crude oil marketing. A coal marketing business was acquired in June 2010, also produced positive incremental margins. The margin increases were partially offset by a higher provision for incentive compensation related to the increased margins and increased employee costs associated with employee additions required to market commodities added in 2010.

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Critical Accounting Estimates

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

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

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 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, goodwill and other intangibles are required to be evaluated whenever indicators of impairment exist and at least annually. We conduct our annual evaluations as of November 1 of each year. 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 result in 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 $353.4 million in goodwill as of December 31, 2011, of which $339.7 million relates to our Black Hills Energy utilities. Colorado Electric carries 69% 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 requires 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, amount and timing of growth capital expenditures, timing and level of success in regulatory rate proceedings, and the cost of debt and equity capital. We believe the goodwill amount reflected the value of the opportunity to construct the recently completed 180 MW of utility-owned generation at the Pueblo Airport Generation Station plus the opportunity to build significant additional amounts of rate-base generation and transmission in the several years after the acquisition 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 $725.8 million as of November 30, 2011, compared to a fair value of $1.2 billion. The fair value exceeds the carrying value by 60.5%; therefore, we do not have an impairment.

The Gas Utilities carry the remaining 31% of the Black Hills Energy goodwill. We tested this goodwill for impairment using an EBITDA multiple method and a discounted cash flows 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 $490.0 million as of November 30, 2011, compared to a fair value of $900.3 million. The fair value exceeds the carrying value by 83.7%; 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, development, abandonment and reclamation activities are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are 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, which required a write-down of $27.8 million after-tax. Under the SEC-defined product prices at December 31, 2011, no additional write-down was required. Reserves in 2011 and 2010 were determined consistent with SEC requirements using a 12-month average price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties. Because of the fluctuations in natural gas and oil prices, we can provide no assurance that future write-downs will not occur.

Oil and Natural Gas Reserve Estimates

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

Despite the inherent imprecision in estimating our oil and natural gas reserves, the estimates are used throughout our financial statements. For example, since we use the unit-of-production method of calculating depletion expense, the amortization rate of our capitalized oil and gas properties incorporates the estimated unit-of-production attributable to the estimates of proved reserves. The net book value of our oil and gas properties is also subject to a "ceiling" limitation based in large part on the 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 non-trading (hedging) purposes. Our typical hedging transactions relate to contracts we enter into to fix the price received for anticipated future production at our Oil and Gas segment, or to fulfill the natural gas hedging plans for gas and electric utilities (see below), and for interest rate swaps we enter into to convert a portion of our variable rate debt, or associated variable rate interest payments, to a fixed rate. Our Energy Marketing segment, now included in discontinued operations as a result of the pending sale expected to be completed in the first quarter of 2012, utilizes various physical and financial contracts to effectively manage a marketing and trading portfolio.

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

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

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. We have interest rate swaps with a notional amount of $250.0 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on the swaps are recorded within the income statement. A 0.01% move in the interest rate curves over the term of the swaps would have a pre-tax impact of approximately $0.4 million. These swaps have remaining terms of 7 and 17 years and have amended mandatory early termination dates ranging from December 15, 2012 to December 16, 2013, respectively.

Counterparty Credit Risk and Allowance for Doubtful Accounts

Our largest counterparties consist primarily of major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and by imposing collateral requirements under certain circumstances, including the use of master netting agreements.

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

Pension and Other Postretirement Benefits

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

The pension benefit cost for 2012 for our non-contributory funded pension plan is expected to be $13.9 million compared to $8.0 million in 2011. The estimated discount rate used to determine annual benefit cost accruals will be 4.65% in 2012; the discount rate used in 2011 was 5.5%. In selecting the discount rate, we consider cash flow durations for each plan's liabilities and returns on high credit quality fixed income yield curves for comparable durations.

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

Change in Assumed Trend Rate	Impact on December 31, 2011 Accumulated Postretirement Benefit Obligation	Impact on 2011 Service and Interest Cost
Increase 1%	$ 2,720	$ 184
Decrease 1%	$ (2,272)	$ (150)

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 carry forwards. 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 current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements.

Liquidity and Capital Resources

The following liquidity and market risk discussion has been revised to reflect the planned divestiture of our Energy Marketing segment.

Overview

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

Financial Position Summary	2011		2010	
Cash and cash equivalents	$21,628		$16,437	
Restricted cash	$9,254		$4,260	
Short-term debt, including current maturities of long-term debt	$347,473		$254,181	
Long-term debt	$1,280,409		$1,186,050	
Stockholders' equity	$1,209,336		$1,100,270	
Ratios				
Long-term debt ratio	51.4	%	51.9	%
Total debt ratio	57.4	%	56.7	%

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity 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 12 months.

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 businesses. In order to take advantage of favorable rates, we have entered into two term loans which were used to repay a portion of our Revolving Credit Facility. Our principal sources for our long-term capital needs 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.

In January 2012, we entered into a definitive agreement to sell our Energy Marketing segment, which resulted in the reporting of this segment as discontinued operations. This divestiture is expected to be completed during the first quarter of 2012 and is expected to provide net cash proceeds of approximately $160 million to $170 million which will primarily be used for future growth projects. Completion of the planned divestiture of our Energy Marketing segment will improve our credit metrics, reduce our overall risk profile and reduce our equity financing needs for planned growth projects.

At December 31, 2011, we had approximately $21.6 million of unrestricted cash on hand in addition to availability under our Revolving Credit Facility. We had the following borrowings, outstanding letters of credit and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Borrowings at December 31, 2011	Letters of Credit at December 31, 2011	Available Capacity at December 31, 2011
	April 14, 2013	$500.0	$195.0	$43.7	$261.3

Revolving Credit Facility
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* The Revolving Credit Facility was replaced when we entered into a new Revolving Credit Facility on February 1, 2012. See Credit Facilities and Long-Term Debt below.

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Working Capital

The most significant items impacting working capital are our capital expenditures, the purchase of natural gas for our Utilities Group and our Power Generation segment and payment of dividends to shareholders. 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 Revolving Credit Facility and cash on hand to meet our peak winter working capital requirements.

Anticipated Financing Plans

We have substantial capital expenditures projected in 2012, a majority of which is due to the construction of additional utility generation to serve our utility customers and comply with environmental standards. Our capital requirements are expected to be financed through a combination of operating cash flows, borrowings on our Revolving Credit Facility, term loans and long-term financings. We may complete an additional long-term financing at the holding company level in 2012 to extend the term of a portion of our short-term debt and refinance obligations coming due in the next 12 to 18 months. We are evaluating financing options including senior unsecured notes, first mortgage bonds, term loans, project financing and equity issuance to fund our capital expenditures. We intend to maintain a consolidated debt-to-capitalization level in the range of 50% to 55%; however, due to significant ongoing capital projects, we may exceed this level on a temporary basis. We anticipate that our existing credit capacity and available cash will be sufficient to fund our working capital needs and our maintenance capital requirements. We do not currently anticipate any difficulty accessing debt or equity markets.

Factors Influencing Liquidity

Many of our operations are subject to seasonal and market-driven fluctuations in cash flow. We have traditionally sourced variations in the working capital needs of our subsidiaries with cash on hand and capacity available under our credit facilities. Increases in commodity prices may also lead to additional liquidity needs.

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 is subject to multiple variables, many 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 significant amounts to our pension plans in 2012 and future periods, which could materially affect our liquidity and results of operations. See Note 18 of the Notes to the Consolidated Financial Statements of this Annual Report on Form 10-K.

Credit Facilities and Long-Term Debt

Revolving Credit Facility

At December 31, 2011, we had a $500 million Revolving Credit Facility with an expiration date of April 14, 2013 which contained an accordion feature which allowed us, with the consent of the administrative agent, to increase the capacity of the facility to $600 million. This Revolving Credit Facility was used for the issuance of letters of credit, to fund working capital needs and for other corporate purposes. Borrowings were available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit under this Revolving Credit Facility was determined based upon our credit ratings. At current year-end credit ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 1.75%, 2.75% and 2.75%, respectively at December 31, 2011. This facility also contained a commitment fee charged on the unused amount of the Revolving Credit Facility. Based upon current year-end credit ratings, the fee was 0.5%.

The Revolving Credit Facility in existence at December 31, 2011 contained 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) consolidated net worth in an amount of not less than the sum of $625 million and 50% of our aggregate consolidated net income, if positive, beginning January 1, 2005 and (ii) a recourse leverage ratio not to exceed 0.65 to 1.00. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with the covenants at December 31, 2011.

Our consolidated net worth was $1.2 billion at December 31, 2011, which was approximately $325.2 million in excess of the net worth we were required to maintain under the credit facility. At December 31, 2011, our long-term debt ratio was 51.4%, our total debt leverage ratio (long-term debt and short-term debt) was 57.4%, and our recourse leverage ratio was approximately 58.5%.

Under the prior Revolving Credit Facilities, our consolidated net worth requirement is calculated by taking $625 million plus 50% of the net income, if positive, of the Company since January 1, 2005. Our long-term debt ratio is the ratio of our long-term debt over long-term debt plus our net worth. Our total debt leverage ratio is the same as our long-term debt ratio with the addition of current maturities of long-term debt and notes payable in the calculation. Our recourse leverage ratio is the ratio of our recourse debt, letters of credit and guarantees issued over our total capital which includes the balance in the numerator plus our net worth.

In order to take advantage of favorable pricing within current market conditions, we entered into a new $500 million Revolving Credit Facility. The new five-year Revolving Credit Facility effective February 1, 2012, now expiring on February 1, 2017, remains at $500.0 million with an accordion feature which allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750.0 million and can be used for the issuance of letters of credit, to fund working capital needs and other corporate purposes. Borrowings are available under a base rate or various Eurodollar rate options. The interest costs associated with letters of credit or borrowings under the agreement are determined based upon our credit ratings. At our current credit rating, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 0.5%, 1.5% and 1.5%, respectively. The facility contains a commitment fee to be charged on the unused amount of the Revolving Credit Facility, which is 0.25% based on current credit ratings.

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

In addition to covenant violations under the prior and new Revolving Credit Facilities, 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 $35 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 prior and new credit facilities prohibit 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.

Corporate Term Loans

In June 2011, we entered into a one-year $150.0 million unsecured, single draw, term loan (the "Term Loan") with CoBank, the Bank of Nova Scotia and U.S. Bank due on June 24, 2012. The cost of borrowing under the Term Loan is based on a spread of 1.25% over LIBOR (1.56% at December 31, 2011). The covenants are substantially the same as those included in the Revolving Credit Facility, and we were in compliance with these covenants as of December 31, 2011.

In December 2010, we entered into a $100 million one-year term loan (the "Loan") with J.P. Morgan and Union Bank. In September 2011, we extended this Loan for two years under the existing terms. The cost of the borrowings under the Loan is based on a spread of 1.375% over LIBOR (which equates to 1.69% at December 31, 2011). Borrowings under the Loan may be prepaid without penalty. The proceeds were used to reduce borrowings on the Revolving Credit Facility. The covenants are substantially the same as under the Revolving Credit Facility and we were in compliance with these covenants as of December 31, 2011.

$200 Million Debt Offering

In July 2010, pursuant to a public offering, we issued $200 million aggregate principal of senior unsecured notes due in 2020. The notes were priced at par and carry a fixed interest rate of 5.88%. We received proceeds of $198.7 million, net of underwriting fees. Proceeds were used to pay down a portion of borrowings on our Revolving Credit Facility and to reduce issued letters of credit.

Black Hills Power

In February 2010, the Black Hills Power Series 8.06% AC bonds matured. These were paid in full for $30.0 million of principal plus accrued interest of $1.2 million.

In March 2010, Black Hills Power completed redemption of its Series Y 9.49% bonds in full. The bonds were originally due in 2018. A total of $2.7 million was paid on March 31, 2010, which includes the principal balance of $2.5 million plus accrued interest and an early redemption premium of 2.618%. The early redemption premium was recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Consolidated Balance Sheets and is being amortized over the remaining term of the original bonds.

In June 2010, Black Hills Power completed redemption of its Series Z 9.35% bonds in full. The bonds were originally due in 2021. A total of $21.8 million was paid on June 1, 2010, which included the principal balance of $20.0 million plus accrued interest and an early redemption premium of 4.675%. The early redemption premium was recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Consolidated Balance Sheets, and is being amortized over the remaining term of the original bonds.

Black Hills Wyoming Project Financing

In December 2009, our subsidiary Black Hills Wyoming issued $120.0 million in project financing debt. The loan amortizes over a seven-year term and matures on December 9, 2016, at which time the remaining balance of $75.6 million is due. Principal and interest payments are made on a quarterly basis with the scheduled principal payments based on projected cash flows available for debt service. Additional quarterly principal payments are required based upon actual cash flows available for debt service. Interest is charged at LIBOR plus 3.25% (3.66% at December 31, 2011). Proceeds were used to repay borrowings on the Revolving Credit Facility. Black Hills Non-regulated Holdings, the parent of Black Hills Wyoming, must maintain minimum equity of $100 million as a covenant of the financing. We were in compliance with this requirement at December 31, 2011.

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, which are permitted only in limited circumstances when cash flows for the projects exceed project debt service and reserve requirements.

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 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, 2011, we recorded a $42.0 million pre-tax unrealized mark-to-market non-cash loss on the swaps. For the year ended December 31, 2010, we recorded a $15.2 million pre-tax unrealized mark-to-market non-cash gain on the swaps. The mark-to-market value on these swaps was a liability of $96.0 million at December 31, 2011. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A 1% move in the interest rate curve over the term of the swaps would have a pre-tax impact of approximately $0.4 million. These swaps are for terms of 7 and 17 years and have amended mandatory early termination dates ranging from December 15, 2012 to December 16, 2013, respectively. We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly 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 million notional amount floating-to-fixed interest rate swaps, having a maximum term of 5 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 $26.9 million at December 31, 2011.

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, most of our Utility Group) to timely pay indebtedness in an aggregate principal amount of $35 million or more, or (ii) the occurrence of a default under any agreement under which we or certain of our subsidiaries (including, among others, most of our Utility Group) may incur indebtedness in an aggregate principal amount of $35 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 Revolving Credit Facility contains default provisions under which an event of default would result if we or certain of our subsidiaries (including, among others, most of our Utility Group) fail to timely make certain payments, such as ERISA funding obligations or payments in satisfaction of judgments, in an aggregate principal amount of $35 million or more.

Equity Issuance

In November 2010, we entered into an Equity Forward Agreement with J.P. Morgan in connection with a public offering of 4,000,000 shares of Black Hills Corporation common stock. On December 7, 2010, the underwriters exercised the over-allotment option to purchase an additional 413,519 shares under the same terms as the original Forward Equity Agreement. We settled the equity forward instrument on November 1, 2011 by physically delivering 4,413,519 shares of common stock in return for proceeds of approximately $120 million.

Collateral

We had posted with counterparties the following amounts of collateral in the form of cash or letters of credit at December 31 (in thousands):

	2011	2010
Utility cash collateral requirements	$ 19,416	$ 10,355

Letters of credit on Revolving Credit Facility	43,700	46,865
Total Funds on Deposit	$ 63,116	$ 57,220

At our Utilities 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 the FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may at their option borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates (3.05% at December 31, 2011). 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, money pool balances included (in thousands):

	Borrowings From (Loans To) Money Pool Outstanding	
	2011	2010
Subsidiary:		
Black Hills Utility Holdings	$273,063	$168,867
Black Hills Power	(50,477)	(39,454)
Cheyenne Light	(15,208)	(14,527)
Total Money Pool borrowings from Parent	$207,378	$114,886

Registration Statements

We have an effective automatic shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our financing arrangements and restrictions imposed by federal and state regulatory authorities. Our articles of incorporation authorize the issuance of 100 million shares of common stock and 25 million shares of preferred stock. As of December 31, 2011, we had approximately 44.0 million shares of common stock outstanding, and no shares of preferred stock outstanding.

Dividend Restrictions

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 of certain statutory limitations or regulatory or financing agreements, we could have restrictions on the amount of distributions allowed to be made by our subsidiaries.

Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenants of our Revolving Credit Facility include the following: a recourse leverage ratio not to exceed 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, 2011, we were in compliance with these covenants.

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. Covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. In addition to the restrictions described above, each state in which we conduct utility operations imposes restrictions on affiliate transactions, including inter-company loans. Additionally, 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, 2011, the restricted net assets at our Electric and Gas Utilities were approximately $61.5 million.

As a covenant of the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted assets of $100.0 million. In addition, Black Hills Wyoming holds $9.3 million of restricted cash associated with the project financing requirements. Black Hills Non-regulated Holdings is the parent of Black Hills Electric Generation, which is the parent of Black Hills Wyoming.

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, 2011, 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, 2011 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 $1.0 million pre-tax based on our December 31, 2011 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 drops to BB+ or below by S&P, or Ba1 or below by Moody's, we would be required to post collateral for the entire amount of the swap's negative mark-to-market fair value.

Capital Requirements

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

	2011		2010		2009	
Property additions [1]:						
Utilities -						
Electric Utilities	$173,078	(2)	$232,466	(2)	$241,963	(2)
Gas Utilities	43,954		51,363		43,005	
Non-regulated Energy -						
Oil and Gas	89,672		40,345		20,522	
Power Generation	98,927	(3)	148,191	(3)	20,537	(3)
Coal Mining	10,438		17,053		11,765	
Corporate	13,279		7,182		9,807	
Capital expenditures for continuing operations	429,348		496,600		347,599	
Discontinued operations investing activities	2,359		390		220	
Total expenditures for property, plant and equipment	431,707		496,990		347,819	
Common stock dividends	59,202		56,467		55,151	
Maturities/redemptions of long-term debt	8,382		59,926		2,173	
Discontinued operations financing activities	158		2,037		2,047	
	$499,449		$615,420		$407,190	

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

(2) Includes (a) $13.1 million and $119.9 million for Wygen III construction in 2010 and 2009, respectively. During 2010 and 2009, we received reimbursement of $59.1 million and $58.0 million from the joint owners of the Wygen III facility. We own 52% of the Wygen III coal-fired plant that went into service on April 1, 2010; (b) $65.8 million, $116.3 million and $48.1 million in 2011, 2010 and 2009, respectively for construction of the 180 MW natural gas-fired generation facility at Colorado Electric, excluding transmission and (c) $23.1 million, $28.0 million and $21.1 million in new transmission projects in 2011, 2010 and 2009, respectively.

(3) Includes $98.2 million, $146.2 million and $16.4 million in 2011, 2010 and 2009, respectively, for construction of the 200 MW natural gas-fired power generation facility at Colorado IPP.

Forecasted Capital Expenditures

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

	2012	2013	2014
Utilities:			
Electric Utilities[1]	$247,000	$371,700	$206,300
Gas Utilities	46,000	54,700	43,800
Non-regulated Energy:			
Oil and Gas	112,200	123,500	126,100
Power Generation	2,850	4,900	6,700
Coal Mining	18,850	7,200	10,800
Corporate	10,300	18,700	12,100
	$437,200	$580,700	$405,800

(1)

Capital expenditures for our Electric Utilities include expenditures associated with our Black Hills Power, Cheyenne Light and Colorado Electric energy resource plans.

Contractual Obligations and Commitments

The following information is provided to summarize our cash obligations and commercial commitments at December 31, 2011. 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)]	$1,283,038	$2,473	$591,446	$92,065	$597,054
Unconditional purchase obligations[(c)]	716,043	199,811	266,885	214,685	34,662
Operating lease obligations[(d)]	14,498	2,799	6,686	2,660	2,353
Other long-term obligations[(e)]	42,914	—	—	—	42,914
Employee benefit plans[(f)]	126,860	13,230	58,640	26,940	28,050
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions[(g)]	49,326	—	22,026	4,029	23,271
Notes payable	345,000	345,000	—	—	—
Total contractual cash obligations[(h)]	$2,577,679	$563,313	$945,683	$340,379	$728,304

(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: $79.2 million in 2012, $70.9 million in 2013, $51.2 million in 2014, $39.6 million in 2015 and $37.9 million in 2016. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2011.

(c) Unconditional purchase obligations include the energy and capacity costs associated with our power purchase agreements, the capacity and certain transmission, gas purchase and gas transportation and storage agreements. The energy charge under the PPA 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 2011 and price assumptions using existing prices at December 31, 2011. Our transmission obligations are based on filed tariffs as of December 31, 2011. A portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure are carried out for 60 days.

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

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

(f) Represents estimated employer contributions to employee benefit plans through the year 2021.

(g) Years 1-3 include an estimated reversal of approximately $10.2 million associated with the gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction. The income tax refund receivable was reversed as a result of an agreement reached with the IRS in 2010.

(h) Amounts in the above table exclude: (1) any obligation that may arise from our derivatives, including interest rate swaps and commodity related contracts that have a negative fair value at December 31, 2011. These amounts have been excluded as it is impracticable to reasonably estimate the final amount and/or timing of any associated payments. (2) A portion of our gas purchases are hedged. These hedges are in place to reduce our customers' underlying exposure to these fluctuations. The impact of these hedges is not included in the above table. (3) The obligations presented above do not include inter-company transactions. (4) The table above does not include obligations of our Energy Marketing segment. See Discontinued Operations discussion below.

Dividends

Our dividend payout ratio for the year ended December 31, 2011, was 118% compared to 82% and 67% for the years ended December 31, 2010 and 2009, respectively. Dividends paid on our common stock totaled $1.46 per share in 2011, as compared to $1.44 per share in 2010 and $1.42 per share in 2009. Our three-year annualized dividend growth rate was 1.4%, and all dividends were paid out of available operating cash flows.

In January 2012, our Board of Directors declared a quarterly dividend of $0.37 per share or an annualized equivalent dividend rate of $1.48 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.

Off-Balance Sheet Arrangements

Guarantees

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2011, we had outstanding guarantees as indicated in the table below. Of the $139.8 million, $121.2 million was related to performance obligations under subsidiary contracts and $18.6 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, 2011, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2011	Year Expiring
Guarantees for payment of 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	384	2012
Guarantees for payment obligations arising from purchase contracts for two gas turbines for Colorado Electric	56	2012
Guarantee for payment obligations relating to a contract to construct 16 wind turbines at Colorado Electric	33,264	2012
Indemnification for subsidiary reclamation/surety bonds	18,601	Ongoing
Guarantee for payment obligations arising from natural gas transportation, storage and services agreement for Black Hills Utility Holdings	10,000	2012
Guarantee for performance and payment obligation of Black Hills Utility Holdings for natural gas supply	7,500	2012
	$139,805	

Discontinued Operations

In January 2012, we entered into a definitive agreement to sell our Energy Marketing segment, Enserco, which resulted in this segment being reported as discontinued operations in the accompanying consolidated financial statements. Until the close of the transaction, a significant item impacting our working capital could be funding our energy marketing activities. Our Energy Marketing segment engages in trading activities, including gas storage, which carry working capital requirements. The level of these requirements varies depending on marketing circumstances, marketing activities and counterparty liquidity requirements. In addition, Enserco's Credit Facility contains working capital requirements for each borrowing base election level.

Credit Facility

Our Energy Marketing segment, Enserco, included in discontinued operations in the accompanying consolidated financial statements, has a $250 million committed credit facility which will expire on May 7, 2012. As of December 31, 2011, there were no borrowings on this facility and there were $91.2 million in outstanding letters of credit. Enserco was in compliance with the covenants included in this facility as of December 31, 2011.

Collateral

Collateral requirements for our Energy Marketing trading positions 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. As of December 31, 2011, Energy Marketing had cash collateral of $49.6

million held at counterparties.

Dividend Restrictions
As discussed above, 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 Enserco Credit Facility is a borrowing base credit facility, the structure of which 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, Enserco may be restricted from making dividend payments to its parent company. Enserco's restricted net assets at December 31, 2011 were $118.6 million.
Contractual Obligations
Unconditional purchase obligations for firm transportation and storage fees for Energy Marketing were $59.9 million and $83.5 million at December 31, 2011 and 2010, respectively. Approximately $22.7 million, $7.2 million and $5.7 million of the firm transportation and storage fees relate to 2012, 2013 and 2014 with the remainder occurring thereafter.

Cash Flow Activities

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

	2011	2010	2009
Cash provided by (used in)			
Operating activities	$223,704	$147,752	$270,502
Investing activities	$(447,007)	$(389,168)	$(269,823)
Financing activities	$249,633	$160,953	$(56,310)

2011 Compared to 2010

Operating Activities:

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

- Cash earnings (net income plus adjustments to reconcile income) were $31.2 million higher than prior year;
- An $11.1 million contribution in 2011 to our defined benefit plans compared to $30.0 million in 2010;
- Increased inflows from operating assets and liabilities of $20.1 million primarily as a result of:
  - Increased cash outflows for materials, supplies and fuel primarily including purchases of natural gas at our Gas Utilities and purchases of additional supplies for generation built to support Colorado Electric customers;
  - Increased cash inflows primarily due to adjustments to our PGA at our Gas Utilities in regulatory assets and regulatory liabilities combined with inflows from energy efficiency rebates; and
  - Cash inflows from accounts receivable and other current assets primarily the result of a settlement reached with the IRS.

Investing Activities:

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

Financing Activities:

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

2010 Compared to 2009

Operating Activities:

Cash provided by operating activities was $147.8 million in 2010, which was $122.8 million less than in 2009. In addition to normal working capital changes, our operating cash flow decline was primarily attributable to:

- Cash earnings (net income plus adjustments to reconcile income) increased $15.2 million;

- A $30.0 million contribution in 2010 to our defined benefit plans compared to $16.9 million in 2009;

- Outflows from operating assets and liabilities of $124.5 million as a result of:

- Materials, supplies and fuel used funds of $37.1 million primarily relating to decreases in the Gas Utilities gas storage in 2009 as compared to 2010; and

- Outflows of $23.9 million from higher use of funds in regulatory assets primarily related to energy efficiency rebates.

Investing Activities:

Cash used in investing activities was $389.2 million in 2010, which was $119.3 million more than in 2009. The increase primarily reflects higher capital additions, partially offset by cash proceeds of $62.0 million from the sale of a portion of Wygen III. During 2010, cash outflows for property, plant and additions totaled $472.3 million. Significant additions during 2010 included partial completion of construction of 180 MW of natural gas-fired electric generation at Colorado Electric and on our 200 MW natural gas-fired electric generation at Black Hills Colorado IPP, new transmission at the Electric Utilities, the completion of Wygen III, and oil and gas property maintenance capital and development drilling.

Financing Activities:

Cash provided by financing activities was $161.0 million in 2010, which was an increase of $217.3 million from 2009. During 2010, we issued $200.0 million in long-term debt and retired $59.9 million in long-term debt. During 2010, we paid $56.5 million of cash dividends on common stock.

Discontinued Operations

During 2011, Energy Marketing had cash outflows for working capital needs of $15.7 million representing accounts receivable, natural gas in storage and accounts payable requirements.

During 2010, Energy Marketing had cash outflows for working capital needs of $14.2 million representing account receivable, natural gas held in storage and accounts payable requirements.

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

- 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.

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

Utilities Group

We produce, purchase and distribute power in four states, and purchase and distribute natural gas in five states. All of our utilities have 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 Utilities Group derivative contracts are summarized below (in thousands):

	December 31, 2011	December 31, 2010
Net derivative liabilities	$(16,676)	$(7,188)
Cash collateral	19,416	10,355
	$2,740	$3,167

Oil and Gas

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 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 90% 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.

We have entered into agreements to hedge a portion of its estimated 2012 and 2013 natural gas and crude oil production. The hedge agreements in place as of December 31, 2011 are as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)	Price
San Juan El Paso	1/8/2010	Swap	01/12 - 03/12	2,500	$6.38
NWR	1/8/2010	Swap	01/12 - 03/12	1,500	$6.47
AECO	1/8/2010	Swap	01/12 - 03/12	500	$6.32
CIG	1/8/2010	Swap	01/12 - 03/12	1,500	$6.43
San Juan El Paso	1/25/2010	Swap	01/12 - 03/12	5,000	$6.44
San Juan El Paso	10/31/2011	Swap	01/12 - 03/12	1,000	$3.71
San Juan El Paso	3/19/2010	Swap	04/12 - 06/12	7,000	$5.27
CIG	3/19/2010	Swap	04/12 - 06/12	1,500	$5.17
NWR	3/19/2010	Swap	04/12 - 06/12	1,500	$5.20
AECO	3/19/2010	Swap	04/12 - 06/12	250	$5.15
San Juan El Paso	10/31/2011	Swap	04/12 - 06/12	1,000	$3.58
San Juan El Paso	6/28/2010	Swap	07/12 - 09/12	3,500	$5.19
NWR	6/28/2010	Swap	07/12 - 09/12	1,500	$5.01
CIG	6/28/2010	Swap	07/12 - 09/12	1,500	$4.98
San Juan El Paso	4/19/2011	Swap	07/12 - 09/12	2,000	$4.45
San Juan El Paso	10/31/2011	Swap	07/12 - 09/12	1,000	$3.77
CIG	2/18/2011	Swap	10/12 - 12/12	500	$4.42
San Juan El Paso	2/18/2011	Swap	10/12 - 12/12	2,500	$4.46
NWR	2/18/2011	Swap	10/12 - 12/12	1,000	$4.44
San Juan El Paso	4/19/2011	Swap	10/12 - 12/12	2,000	$4.62
San Juan El Paso	10/31/2011	Swap	10/12 - 12/12	1,000	$3.94
San Juan El Paso	12/9/2011	Swap	10/12 - 12/12	1,000	$3.59
San Juan El Paso	4/19/2011	Swap	01/13 - 03/13	2,500	$5.03
San Juan El Paso	6/6/2011	Swap	01/13 - 03/13	2,500	$5.18
San Juan El Paso	10/31/2011	Swap	01/13 - 03/13	1,000	$4.32
San Juan El Paso	12/9/2011	Swap	01/13 - 03/13	1,000	$3.91
NWR	12/9/2011	Swap	01/13 - 03/13	1,000	$4.02
San Juan El Paso	4/19/2011	Swap	04/13 - 06/13	2,500	$4.64
San Juan El Paso	10/31/2011	Swap	04/13 - 06/13	1,000	$4.13
San Juan El Paso	12/9/2011	Swap	04/13 - 06/13	1,000	$3.77
NWR	12/9/2011	Swap	04/13 - 06/13	1,000	$3.83
San Juan El Paso	10/31/2011	Swap	07/13 - 09/13	1,000	$4.27
San Juan El Paso	12/9/2011	Swap	07/13 - 09/13	1,000	$3.95
NWR	12/9/2011	Swap	07/13 - 09/13	1,000	$3.97
San Juan El Paso	12/9/2011	Swap	10/13 - 12/13	1,000	$4.05
NWR	12/9/2011	Swap	10/13 - 12/13	1,000	$4.08

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	1/8/2010	Put	01/12 - 03/12	5,000	$75.00
NYMEX	1/25/2010	Swap	01/12 - 03/12	5,000	$83.30
NYMEX	2/26/2010	Swap	01/12 - 03/12	5,000	$83.80
NYMEX	3/19/2010	Swap	01/12 - 03/12	5,000	$83.80
NYMEX	3/4/2011	Swap	01/12 - 12/12	2,000	$104.60
NYMEX	3/19/2010	Swap	04/12 - 06/12	5,000	$84.00
NYMEX	3/31/2010	Put	04/12 - 06/12	5,000	$75.00
NYMEX	5/13/2010	Swap	04/12 - 06/12	5,000	$87.85
NYMEX	8/17/2010	Swap	04/12 - 06/12	3,000	$82.60
NYMEX	6/28/2010	Swap	07/12 - 09/12	5,000	$83.80
NYMEX	8/17/2010	Swap	07/12 - 09/12	5,000	$82.85
NYMEX	9/16/2010	Swap	07/12 - 09/12	5,000	$84.60
NYMEX	4/20/2011	Swap	07/12 - 06/13	2,000	$106.80
NYMEX	10/17/2011	Put	07/12 - 09/13	2,000	$80.00
NYMEX	10/17/2011	Call	07/12 - 09/13	2,000	$95.00
NYMEX	11/9/2010	Swap	10/12 - 12/12	5,000	$91.10
NYMEX	1/6/2011	Swap	10/12 - 12/12	5,000	$93.40
NYMEX	2/17/2011	Swap	10/12 - 03/13	5,000	$97.85
NYMEX	1/20/2011	Swap	01/13 - 03/13	5,000	$94.20
NYMEX	3/4/2011	Swap	01/13 - 03/13	3,000	$103.35
NYMEX	11/2/2011	Call	01/13 - 12/13	3,000	$100.00
NYMEX	11/2/2011	Put	01/13 - 12/13	3,000	$77.50
NYMEX	6/3/2011	Swap	04/13 - 06/13	5,000	$100.90
NYMEX	7/27/2011	Swap	04/13 - 06/13	5,000	$102.72
NYMEX	12/9/2011	Call	04/13 - 06/13	2,000	$100.50
NYMEX	12/9/2011	Put	04/13 - 06/13	2,000	$90.00
NYMEX	7/27/2011	Swap	07/13 - 12/13	5,000	$102.75
NYMEX	10/17/2011	Swap	07/13 - 09/13	2,000	$88.50
NYMEX	12/9/2011	Call	07/13 - 09/13	3,000	$99.00
NYMEX	12/9/2011	Put	07/13 - 09/13	3,000	$90.00
NYMEX	12/9/2011	Call	10/13 - 12/13	4,000	$98.00
NYMEX	12/9/2011	Put	10/13 - 12/13	4,000	$90.00

Our hedge agreements had a fair value of approximately $5.6 million as of December 31, 2011.

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, 2011, we had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 5 years. These swaps have been designated as hedges in accordance with accounting standards for derivatives and hedges and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheets.

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 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 2011 and 2010 we recorded a $42.0 million and a $15.2 million pre-tax unrealized mark-to-market loss to earnings, respectively, while in 2009 we recorded a $55.7 million pre-tax unrealized mark-to-market gain to earnings. These swaps are 7 and 17 year swaps which have amended mandatory early termination dates ranging from December 15, 2012 to December 16, 2013, respectively.

We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly our upcoming holding company debt maturities, which are $225 million and $250 million in 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, 2011 and 2010, our interest rate swaps and related balances were as follows (dollars in thousands):

	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)
December 31, 2011									
Interest rate swaps	$150,000	5.04 %	5.0	$—	$—	$ 6,513	$ 20,363	$ (26,876)	$—
Interest rate swaps - De-designated	250,000	5.67 %	2.0	—	—	75,295	20,696	—	(42,010)
	$400,000			$—	$—	$ 81,808	$ 41,059	$ (26,876)	$(42,010)
December 31, 2010									
	$150,000	5.04 %	6.0	$—	$—	$ 6,823	$ 14,976	$ (21,799)	$—

Interest rate swaps									
Interest rate swaps - De-designated	250,000	5.67 %	1.0	—	—	53,980	—	—	(15,193)
	$400,000			$—	$—	$ 60,803	$ 14,976	$ (21,799)	$(15,193)

Based on December 31, 2011 market interest rates and balances, a loss of approximately $6.5 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

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

	2012	2013	2014	2015	2016	Thereafter	Total
Long-term debt							
Fixed rate[a]	$73	$225,000	$256,450	$—	$—	$577,200	$1,058,723
Average interest rate [b]	13.66%	6.5%	8.89%	—%	—%	6.27%	6.95%
Variable rate	$2,400	$103,973	$6,023	$6,964	$85,101	$19,854	$224,315
Average interest rate [b]	3.66%	1.76%	3.66%	3.66%	3.66%	0.55%	2.51%
Total long-term debt	$2,473	$328,973	$262,473	$6,964	$85,101	$597,054	$1,283,038
Average interest rate [b]	3.95%	5%	8.77%	3.66%	3.66%	6.08%	6.18%

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

Credit Risk

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

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

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

At December 31, 2011, approximately 75% of our credit exposure (including our Energy Marketing segment but 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.

Trading Activities

Energy Marketing

As of December 31, 2011, we have a natural gas, crude oil, coal, power and environmental marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in 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, crude oil, coal, power and environmental products.

On January 18, 2012, we entered into a definitive agreement to sell all of the outstanding stock of Enserco, which resulted in the Energy Marketing segment being reported as discontinued operations. This transaction is expected to close in the first quarter of 2012.

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.

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, oil, coal, power and environmental 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.

Fair Value of Energy Marketing Positions

The following table provides a reconciliation of activity in our marketing portfolio that has been recorded at fair value in accordance with GAAP during the year ended December 31, 2011 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2010	$23,418	(a)
Net cash settled during the period on positions that existed at December 31, 2009	(3,376	)
Change in fair value due to change in assumptions	—	
Unrealized gain (loss) on new positions entered during the period and still existing at December 31, 2011	34,577	
Realized (gain) losses on positions that existed at December 31, 2010 and were settled during the period	(12,941	)
Change in cash collateral	4,086	
Unrealized gain (loss) on positions that existed at December 31, 2010 and still existed at December 31, 2011	(23,548	)
Total fair value of energy marketing positions at December 31, 2011	$22,216	(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, 2011		December 31, 2010	
Net derivative assets	$18,731		$28,524	
Cash collateral	8,044		3,958	
Market adjustment recorded in material, supplies and fuel	(4,558	)	(9,064	)

Total fair value of energy marketing positions marked-to-market	$22,217	$23,418

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.

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

	Maturities		
Source of Fair Value	Less than 1 year	1 - 2 years	Total Fair Value
Level 1	$—	$—	$—
Level 2	5,371	12,631	18,002
Level 3	(2,806)	3,535	729
Cash collateral	8,044	—	8,044
Market value adjustment for inventory (see footnote (a) above)	—	—	—
Total fair value of our energy marketing positions	$10,609	$16,166	$26,775

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 2011 or pending adoption.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2011 and 2010, and the related consolidated statements of income, comprehensive income (loss), common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, 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 29, 2012 expressed an adverse opinion on the Company's internal control over financial reporting because of a material weakness.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 29, 2012

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Years ended	December 31, 2011	December 31, 2010	December 31, 2009
	(in thousands, except per share amounts)		
Revenue:			
Utilities	$1,155,519	$1,109,761	$1,091,638
Non-regulated energy	116,669	109,930	107,074
Total revenue	1,272,188	1,219,691	1,198,712
Operating expenses:			
Utilities -			
Fuel, purchased power and cost of gas sold	574,989	566,967	595,240
Operations and maintenance	247,496	251,375	241,995
Non-regulated energy operations and maintenance	93,453	71,672	76,137
Gain on sale of operating assets	—	(8,921)	(25,971)
Depreciation, depletion and amortization	135,591	126,606	120,938
Impairment of long-lived assets	—	—	43,301
Taxes - property, production and severance	33,710	27,592	21,687
Other operating expenses	710	980	1,230
Total operating expenses	1,085,949	1,036,271	1,074,557
Operating income	186,239	183,420	124,155
Other income (expense):			
Interest charges -			
Interest expense (including amortization of debt issuance costs, premiums and discounts, realized amount on interest rate swaps)	(116,684)	(105,676)	(89,441)
Allowance for funds used during construction - borrowed	14,041	10,689	5,839
Capitalized interest	11,260	4,381	349
Unrealized (loss) gain on interest rate swaps, net	(42,010)	(15,193)	55,653
Interest income	2,017	541	923
Allowance for funds used during construction - equity	932	2,996	5,891
Other expense	(817)	(140)	(513)
Other income	2,490	2,733	5,921
Total other income (expense)	(128,771)	(99,669)	(15,378)
Income (loss) from continuing operations before earnings (loss) of unconsolidated subsidiaries and income taxes	57,468	83,751	108,777
Equity in earnings (loss) of unconsolidated subsidiaries	1,121	1,559	1,343
Income tax (expense) benefit	(18,224)	(22,169)	(32,851)
Income (loss) from continuing operations	40,365	63,141	77,269
Income (loss) from discontinued operations, net of tax	9,365	5,544	4,286
Net income available for common stock	$49,730	$68,685	$81,555
Income (loss) per share, Basic -			
Income (loss) from continuing operations, per share	$1.01	$1.62	$2.00
Income (loss) from discontinued operations, per share	0.24	0.14	0.11

Total income (loss) per share, Basic	$1.25	$1.76	$2.11
Income (loss) per share, Diluted -			
Income (loss) from continuing operations, per share	$1.01	$1.62	$2.00
Income (loss) from discontinued operations, per share	0.23	0.14	0.11
Total income (loss) per share, Diluted	$1.24	$1.76	$2.11
Weighted average common shares outstanding:			
Basic	39,864	38,916	38,614
Diluted	40,081	39,091	38,684

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Years ended	December 31, 2011 (in thousands)	December 31, 2010	December 31, 2009
Net income available for common stock	$49,730	$68,685	$81,555
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments	(7,934)	(1,521)	4,491
Fair value adjustment on derivatives designated as cash flow hedges	(2,831)	1,336	(17,481)
Reclassification adjustment of cash flow hedges settled and included in net income (loss)	1,468	(4,232)	12,609
Reclassification adjustment of cash flow hedges settled and included in regulatory assets or liabilities	—	—	—
Other comprehensive income (loss), net of tax	(9,297)	(4,417)	(381)
Comprehensive income (loss)	$40,433	$64,268	$81,174

See Note 15 for additional disclosures related to Comprehensive Income

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2011	December 31, 2010
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$21,628	$16,437
Restricted cash	9,254	4,260
Accounts receivable, net	156,774	171,816
Materials, supplies and fuel	84,064	62,915
Derivative assets, current	18,583	12,710
Income tax receivable, net	9,344	—
Deferred income tax assets, net, current	37,202	20,664
Regulatory assets, current	59,955	66,429
Other current assets	21,266	14,695
Assets of discontinued operations	340,851	314,235
Total current assets	758,921	684,161
Investments	17,261	17,780
Property, plant and equipment	3,724,016	3,353,509
Less accumulated depreciation and depletion	(934,441)	(861,775)
Total property, plant and equipment, net	2,789,575	2,491,734
Other assets:		
Goodwill	353,396	353,396
Intangible assets, net	3,843	4,069
Derivative assets, non-current	1,971	2,625
Regulatory assets, non-current	182,175	138,405
Other assets, non-current	19,941	19,339
Total other assets	561,326	517,834
TOTAL ASSETS	$4,127,083	$3,711,509

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(continued)

	As of December 31, 2011	December 31, 2010
	(in thousands, except share amounts)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$104,748	$146,556
Accrued liabilities	151,319	147,643
Derivative liabilities, current	84,367	64,617
Accrued income tax, net	—	3,348
Regulatory liabilities, current	16,231	3,943
Notes payable	345,000	249,000
Current maturities of long-term debt	2,473	5,181
Liabilities of discontinued operations	173,929	173,323
Total current liabilities	878,067	793,611
Long-term debt, net of current maturities	1,280,409	1,186,050
Deferred credits and other liabilities:		
Deferred income tax liabilities, net, non-current	300,988	275,842
Derivative liabilities, non-current	49,033	17,897
Regulatory liabilities, non-current	108,217	84,611
Benefit plan liabilities	177,480	124,709
Other deferred credits and other liabilities	123,553	128,519
Total deferred credits and other liabilities	759,271	631,578
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: 43,957,502 shares at 2011 and 39,280,048 shares at 2010, respectively	43,958	39,280
Additional paid-in capital	722,623	598,805
Retained earnings	476,603	486,075
Treasury stock at cost - 32,766 shares at 2011 and 10,962 shares at 2010, respectively	(970)	(309)
Accumulated other comprehensive income (loss)	(32,878)	(23,581)
Total stockholders' equity	1,209,336	1,100,270
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,127,083	$3,711,509

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended	December 31, 2011	December 31, 2010	December 31, 2009
	(in thousands)		
Operating activities:			
Net income	$49,730	$68,685	$81,555
(Income) loss from discontinued operations, net of tax	(9,365)	(5,544)	(4,286)
Income (loss) from continuing operations	40,365	63,141	77,269
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities -			
Depreciation, depletion and amortization	135,591	126,606	120,938
Impairment of long-lived assets	—	—	43,301
Gain on sale of operating assets	—	(8,921)	(25,971)
Stock compensation	5,643	5,637	3,908
Unrealized mark-to-market loss (gain) on interest rate swaps	42,010	15,193	(55,653)
Equity in (earnings) loss of unconsolidated subsidiaries	(1,121)	(1,559)	(1,343)
Allowance for funds used during construction - equity	(932)	(2,996)	(5,891)
Derivative fair value adjustments	(8,693)	13,546	19,083
Deferred income taxes	33,600	17,354	45,610
Employee benefit plans	14,586	16,342	16,349
Other adjustments	10,602	(3,851)	4,539
Change in certain operating assets and liabilities-			
Materials, supplies and fuel	(21,385)	(338)	36,767
Accounts receivable and other current assets	(4,202)	(18,480)	26,593
Accounts payable and other current liabilities	(31,091)	(12,848)	4,404
Regulatory assets	12,691	(21,283)	2,598
Regulatory liabilities	11,198	50	1,265
Contributions to defined pension plans	(11,050)	(30,015)	(16,945)
Other operating activities	(11,118)	(1,013)	7,091
Net cash provided by operating activities of continuing operations	216,694	156,565	303,912
Net cash provided by (used in) operating activities of discontinued operations	7,010	(8,813)	(33,410)
Net cash provided by operating activities	223,704	147,752	270,502
Investing activities:			
Property, plant and equipment additions	(440,698)	(472,292)	(346,650)
Payment for acquisition of net assets, net of cash acquired	—	(2,250)	—
Proceeds from sale of operating assets	583	70,357	84,661
Working capital adjustment - Aquila Transaction	—	—	7,880
Other investing activities	(4,533)	15,407	(15,494)
Net cash provided by (used in) investing activities of continuing operations	(444,648)	(388,778)	(269,603)
Net cash provided by (used in) investing activities of discontinued operations	(2,359)	(390)	(220)
Net cash provided by (used in) investing activities	(447,007)	(389,168)	(269,823)
Financing activities:			
Dividends paid on common stock	(59,202)	(56,467)	(55,151)

Common stock issued	123,041	3,246	4,819
Short-term borrowings - repayments	(821,300)	(770,000)	(1,125,300)
Short-term borrowings - issuances	1,017,300	854,500	586,000
Long-term debt - issuance	—	200,000	543,069
Long-term debt - repayments	(8,382)	(59,926)	(2,173)
Other financing activities	(1,666)	(8,363)	(5,527)
Net cash provided by (used in) financing activities of continuing operations	249,791	162,990	(54,263)
Net cash provided by (used in) financing activities of discontinued operations	(158)	(2,037)	(2,047)
Net cash provided by (used in) financing activities	249,633	160,953	(56,310)
Net change in cash and cash equivalents	26,330	(80,463)	(55,631)
Cash and cash equivalents beginning of year *	32,438	112,901	168,532
Cash and cash equivalents end of year *	$58,768	$32,438	$112,901

* Cash and cash equivalents include cash of discontinued operations of $37.1 million, $16.0 million, $97.5 million and $94.7 million at December 31, 2011, 2010, 2009 and 2008, respectively.

See Note 16 for supplemental disclosure of cash flow information

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

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BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(in thousands except share and per share amounts)	Common Stock		Treasury Stock					
	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Total
Balance at December 31, 2008	38,676,054	$38,676	40,183	$(1,392)	$584,582	$447,453	$(18,783)	$1,050,536
Net income (loss) available for common stock	—	—	—	—	—	81,555	—	81,555
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(381)	(381)
Dividends on common stock	—	—	—	—	—	(55,151)	—	(55,151)
Share-based compensation	158,140	159	(31,349)	1,168	4,830	—	—	6,157
Tax effect of share-based compensation	—	—	—	—	(120)	—	—	(120)
Dividend reinvestment and stock purchase plan	143,332	143	—	—	2,098	—	—	2,241
Balance at December 31, 2009	38,977,526	$38,978	8,834	$(224)	$591,390	$473,857	$(19,164)	$1,084,837
Net income (loss) available for common stock	—	—	—	—	—	68,685	—	68,685
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(4,417)	(4,417)
Dividends on common stock	—	—	—	—	—	(56,467)	—	(56,467)
Share-based compensation	195,915	196	2,128	(85)	4,706	—	—	4,817
Tax effect of share-based compensation	—	—	—	—	(33)	—	—	(33)
Equity forward	—	—	—	—	(288)	—	—	(288)
Dividend reinvestment and stock purchase plan	106,231	106	—	—	3,035	—	—	3,141
Other stock transactions	376	—	—	—	(5)	—	—	(5)
Balance at December 31, 2010	39,280,048	$39,280	10,962	$(309)	$598,805	$486,075	$(23,581)	$1,100,270
Net income (loss) available for common stock	—	—	—	—	—	49,730	—	49,730
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(9,297)	(9,297)
Dividends on common stock	—	—	—	—	—	(59,202)	—	(59,202)
Share-based compensation	161,424	161	21,804	(661)	5,576	—	—	5,076
Tax effect of share-based compensation	—	—	—	—	(28)	—	—	(28)
Issuance of common stock	4,413,519	4,414	—	—	115,216	—	—	119,630
Dividend reinvestment and stock purchase plan	102,511	103	—	—	3,099	—	—	3,202
Other stock transactions	—	—	—	—	(45)	—	—	(45)
Balance at December 31, 2011	43,957,502	$43,958	32,766	$(970)	$722,623	$476,603	$(32,878)	$1,209,336

Dividends per share paid were $1.46, $1.44 and $1.42 for the years ended December 31, 2011, 2010 and 2009, respectively.

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

BLACK HILLS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2011, 2010 and 2009

(1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

Business Description

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

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

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

In January 2012, we entered into a definitive agreement to sell Enserco, our non-regulated Energy Marketing segment, which resulted in this segment being reported as discontinued operations. Our Energy Marketing segment engages in marketing natural gas, crude oil, coal, power and environmental products in the United States and Canada. See Notes 23 and 25 for additional information.

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

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Management evaluates its estimates and related assumptions regularly, including, but not limited to, those related to the market value of derivatives, intangible asset valuations and useful lives, long-lived asset values and useful lives, proved oil and gas reserve volumes, actuarially determined employee benefit costs, valuation of deferred taxes and contingencies. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned subsidiaries. Investment in non-controlled entities over which we have the ability to exercise significant influence over operating and financial policies are accounted for using the equity method of accounting. In applying the equity method of accounting, the investments are initially recognized at cost, and subsequently adjusted for our proportionate share of earnings and losses and distributions. Under this method, a proportionate share of pretax income is recorded as Equity earnings (loss) of unconsolidated subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. For additional information on intercompany revenues, see Note 17.

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, and the BHEP gas processing plant. See Note 7 for additional information.

As a result of the pending sale of our Energy Marketing segment, amounts associated with this segment have been reclassified as discontinued operations on the accompanying Consolidated Financial Statements. See note 23 for additional information.

Restatement - Subsequent to the issuance of the Company's 2010 consolidated financial statements, the Company's management determined that certain intercompany transactions with our rate regulated operations had not been properly eliminated in consolidation, resulting in an overstatement of Utility and Non-regulated revenue and Fuel, purchased power and cost of gas sold of $59.6 million and $57.5 million in aggregate for the year ended December 31, 2010 and December 31, 2009, respectively. As such, the Consolidated Financial Statements have been restated for the correction of this error. The error did not have an impact on our gross margin, net income, total assets or cash flows.

Cash and Cash Equivalents and Restricted Cash

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

The Black Hills Wyoming project financing 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.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable for our Utilities Group consists of sales to residential, commercial, industrial, municipal and other customers, all of which do not bear interest. These accounts receivable are stated at billed and unbilled amounts net of write-offs and allowance for doubtful accounts. Accounts receivable for our Non-regulated Energy Group consists of amounts due from sales of coal, crude oil and natural gas, electric energy and capacity.
Our Utilities Group utilizes master netting agreements which consists of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

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

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.
Following is a summary of accounts receivable as of December 31 (in thousands):

2011	Accounts Receivable, Trade	Unbilled Revenues	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$42,773	$21,151	$(545)	$63,379
Gas	39,353	38,992	(1,011)	77,334

Oil and Gas	11,282	—	(105	) 11,177
Coal Mining	4,056	—	—	4,056
Power Generation	282	—	—	282
Corporate	546	—	—	546
Total	$98,292	$60,143	$(1,661	) $156,774

2010	Accounts Receivable, Trade	Unbilled Revenues	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$51,005	$19,572	$(708)	$69,869
Gas	41,970	40,376	(1,425)	80,921
Oil and Gas	6,213	—	(161)	6,052
Coal Mining	2,420	—	—	2,420
Power Generation	307	—	—	307
Corporate	12,247	—	—	12,247
Total	$114,162	$59,948	$(2,294)	$171,816

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. Sales tax collected from our customers is recorded on a net basis (excluded from Revenue).

Utility revenues are based on authorized rates approved by the state regulatory agencies and the FERC. Revenues related to the sale, transmission and distribution of energy, and delivery of service are generally recorded when service is rendered or energy is delivered to customers. 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 in Accounts receivable, net on the accompanying Consolidated Balance Sheets.

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.

Materials, Supplies and Fuel

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

	December 31, 2011	December 31, 2010
Materials and supplies	$40,838	$31,537
Fuel - Electric Utilities	8,201	9,687
Natural gas in storage - Gas Utilities	35,025	21,691
Total Materials, supplies and fuel	$84,064	$62,915

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

Property, Plant and Equipment

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

The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage, is charged to accumulated depreciation. Removal costs associated with non-legal obligations related to our regulated properties are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets, except for crude oil and natural gas properties as described below, 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 reclamation and abandonment costs, net of estimated salvage values are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonment of properties, are 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 and held constant for the life of the reserves. An average price is calculated using the price at the first day of each month for each of the preceding 12 months. If the net capitalized costs exceed the full cost "ceiling" at period end, a permanent non-cash write-down would be charged to earnings in that period. No ceiling test write-down was recorded in 2011 or 2010. 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. See Note 12 for additional information.

The SEC definition of "reliable technology" permits the use of any reliable technology to establish reserve volumes in addition to those established by production and flow test data. This definition allows, but does not require us, to calculate PUDs to be booked at more than one location away from a producing well. We elected to include PUDs of only one location away from a producing well in our volume reserve estimate. See information on our oil and gas drilling activities in Note 21.

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

Goodwill and Intangible Assets

Under accounting standards for goodwill and intangible assets, goodwill and intangible assets with indefinite lives are not amortized but the carrying values are reviewed at least 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).

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

The substantial majority of our goodwill and intangible assets are contained within the Utilities Group. Goodwill primarily arose from the acquisition of one regulated electric and four regulated gas utilities from Aquila of which 69% was allocated to Colorado Electric and 31% was allocated to the Gas Utilities. Changes to goodwill during the years ended December 31 relating primarily to taxes, were as follows (in thousands):

	Electric Utilities	Gas Utilities	Power Generation	Total
Ending balance at December 31, 2009	$249,620	$93,914	$8,765	$352,299
Additions (adjustments)	867	230	—	1,097
Ending balance at December 31, 2010	$250,487	$94,144	$8,765	$353,396
Additions (adjustments)	—	—	—	—
Ending balance at December 31, 2011	$250,487	$94,144	$8,765	$353,396

Intangible assets represent easements, rights-of-way and trademarks and are amortized using a straight-line method using estimated useful lives of 20 years. Changes to intangible assets were as follows (in thousands):

	2011	2010	2009
Intangible assets, net, beginning balance	$4,069	$4,309	$4,884
Additions (adjustments)	—	—	(365)
Amortization expense	(226)	(240)	(210)
Intangible assets, net, ending balance	$3,843	$4,069	$4,309

* Amortization expense for existing intangible assets is expected to be $0.2 million, $0.2 million, $0.2 million, $0.2 million, and $0.2 million for 2012, 2013, 2014, 2015, and 2016, respectively.

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. Additional information is included in Note 10.

Fair Value Measurements

Accounting standards for fair value measurements and accounting for compensation - retirement benefits require, among other things, 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.

We utilize several different valuation techniques to measure the fair value of assets and liabilities.

- Commodity derivatives - Oil and Gas: Our derivative option contracts are valued under the income approach using option pricing models based on data either readily observable in public markets, derived from public markets or provided by counterparties who regularly trade in public markets. Our derivative swap contracts are valued under the income approach using a discounted cash flow model based on data either readily observable or derived from public markets.

- Commodity derivatives - Utilities: Our gas hedge portfolio for our Utilities generally consists of futures, basis swaps and option contracts. The fair value of these financial instruments is estimated based on market trading information, where available. Absent published market values for an instrument or other asset, management uses observable market data to arrive at its estimates of fair value. These contracts have been classified as Level 2 measurements.

- Interest rate swaps: The fair value of our interest rate swap contracts are determined using standard valuation models. The significant inputs used in these models are readily available in public markets or can be derived from observable market transactions and; therefore, these derivative contracts have been classified as Level 2. Inputs used in these standard valuation models include the applicable market forward rates and discount rates.

Additional information is included in Note 4.

Derivatives and Hedging Activities

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

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

Deferred Financing Costs

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

Development Costs

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

Legal Costs

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

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 the 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 numerous rate-making 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. Our regulatory assets represent amounts for which we will recover the cost, but are not allowed a return. In the event we determine that Black Hills Power, Cheyenne Light, Colorado Gas, Colorado Electric, Nebraska Gas, Iowa Gas or Kansas Gas 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.

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

	Maximum Recovery or Settlement Period (in years)	As of December 31, 2011	As of December 31, 2010
Regulatory assets			
Deferred energy and fuel costs adjustments - current	1	$33,526	$30,298
Deferred gas cost adjustments and gas price derivatives	1	26,208	39,407
AFUDC	45	12,482	13,391
Employee benefit plans	13	120,708	83,144
Environmental	subject to approval	1,770	2,353
Asset retirement obligations	44	3,097	3,066
Bond issue cost	25	3,704	3,847
Renewable energy standard adjustment	5	20,095	14,254
Flow through accounting	35	12,191	7,491
Other regulatory assets	various	8,349	7,583
		$242,130	$204,834
Regulatory liabilities			
Deferred energy and gas costs	1	$16,961	$1,200
Employee benefit plans	13	59,455	36,155
Cost of removal	44	42,257	39,638

Revenue subject to refund	1	443	1,016
Other regulatory liabilities	various	5,332	10,545
		$124,448	$88,554

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

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

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.

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.

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

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

Asset Retirement Obligations - Asset retirement obligations represent the estimated recoverable costs for legal obligations associated with the retirement of a tangible long-lived asset. See Note 10 for additional details.

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

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

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

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

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

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

Cost of Removal - Cost of removal 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.

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.

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 carry forwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. We classify deferred tax assets and liabilities into current and non-current amounts based on the nature of the related assets and liabilities.

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

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

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

Earnings per Share of Common Stock

Basic earnings per share from continuing operations is computed by dividing Income (loss) from continuing operations 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 (loss) from continuing operations and basic and diluted share amounts is as follows (in thousands):

	December 31, 2011	December 31, 2010	December 31, 2009
Income (loss) from continuing operations	$40,365	$63,141	$77,269
Weighted average shares - basic *	39,864	38,916	38,614
Dilutive effect of:			
Stock options	19	14	—
Restricted stock	153	107	66
Equity forward instrument	—	29	—
Other dilutive effects	45	25	4
Weighted average shares - diluted	40,081	39,091	38,684

* On November 1, 2011, we issued shares in conjunction with the settlement of an equity forward agreement. See Note 11 for further information.

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):

	December 31, 2011	December 31, 2010	December 31, 2009
Options to purchase common stock	105	158	462
Restricted stock	17	1	3
Other	19	1	45
	141	160	510

Discontinued Operations

Assets of discontinued operations are recorded at the lower of their carrying amount or fair value less cost to sell. Additionally, in accordance with GAAP, indirect corporate costs previously allocated to a disposal group cannot be reclassified to discontinued operations. As of December 31, 2011, Assets of discontinued operations and Liabilities of discontinued operations on the accompanying Consolidated Balance Sheets included the assets and liabilities of Enserco Energy, Inc. See Note 23 for additional information.

(2) RECENTLY ISSUED AND ADOPTED ACCOUNTING PRONOUNCEMENTS AND LEGISLATION

Recently Adopted Accounting Standards

Other Comprehensive Income, ASU No. 2011-05 and ASU 2011-12

FASB issued an accounting standards update amending ASC 220 to improve the comparability, consistency and transparency of reporting of comprehensive income. It amends existing guidance by allowing only two options for presenting the components of net income and other comprehensive income: (1) in a single continuous financial statement, statement of comprehensive income or (2) in two separate but consecutive financial statements, consisting of an income statement followed by a separate statement of other comprehensive income. Also, items that are reclassified from other comprehensive income to net income must be presented on the face of the financial statements. ASU No. 2011-05 requires retrospective application, and it is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, with early adoption permitted. In December 2011, FASB issued ASU 2011-12. ASU 2011-12 indefinitely deferred the provisions of ASU 2011-05 requiring the presentation of reclassification adjustments on the face of the financial statements for items reclassified from other comprehensive income to net income.

We have elected to early adopt the provisions of ASU 2011-05 as amended by ASU 2011-12. The adoption changed our presentation of certain financial statements and provided additional details in notes to the financial statements, but did not have any other impact on our consolidated financial statements. See additional Comprehensive Income Statement and additional disclosures in Note 15.

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 Oil and Gas segment, interest rate swap instruments, and other miscellaneous financial instruments.

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, disclosure of inputs and techniques used in valuation 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 are required to be presented separately. These disclosures are required for interim and annual reporting periods and were effective for us January 1, 2010, except the disclosures related to purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which were effective January 1, 2011. The guidance requires additional disclosures, but did not impact our financial position, results of operations or cash flows. The additional disclosures are included in Note 4.

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," which amended 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 oil and gas prices used to determine reserves from the period-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 before the end of the reporting period. The amendment was effective for 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 the fourth quarter of 2009.

Dodd-Frank Wall Street Reform and Consumer Protection Act

In July 2010, the President of the United States signed into law comprehensive financial reform legislation under Dodd-Frank. Title VII of Dodd-Frank effectively regulates many derivative transactions in the United States that were previously unregulated, including swap transactions in the over-the-counter market. Among other things, Dodd-Frank (i) mandates the clearing of some swaps through regulated central clearing organizations and the trading of clearing swaps through regulated exchanges or swap execution facilities, in each case subject to certain key exemptions, and (ii) authorizes regulators to establish collateral and margin requirements for certain swap transactions that are not cleared. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users, and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions.

In December 2011, the SEC issued Final Rule 33-9286 providing requirements for Section 1503 of Dodd-Frank. This release requires issuers that are operators of a coal mine to disclose information concerning mine safety violations or other regulatory matters. The required information for our WRDC coal mine is included in Exhibit 95 of this Form 10-K.

Significant rule-making by numerous governmental agencies, particularly the CFTC with respect to non-security commodities, will be required in order to implement the restrictions, limitations, and requirements contemplated by Dodd-Frank. We will continue to evaluate the impact as these rules become available.

Recently Issued Accounting Pronouncements and Legislation

Intangibles - Goodwill and Other, ASU No. 2011-08

In September 2011, the FASB issued an amendment to an existing accounting standard, which provides an option to perform a qualitative assessment to determine whether further impairment testing on goodwill is necessary. Specifically, an entity has the option to first assess qualitative factors to determine whether it is necessary to perform the current two-step test. If an entity believes, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount, the quantitative impairment test is required. Otherwise, no further testing is required. This standard is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The adoption of this standard will not have a material impact on our financial statements.

Fair Value Measurement, ASU No. 2011-04

FASB issued an accounting standards update amending ASC 820 to achieve common fair value measurement and disclosure requirements between GAAP and IFRS. This amendment changes the wording used to describe fair value and requires additional disclosures. We do not expect this amendment, which is effective for interim and annual periods beginning after December 31, 2011, to have an impact on our financial position, results of operations, or cash flows.

(3) RISK MANAGEMENT ACTIVITIES

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

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

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

- Interest rate risk associated with variable rate credit facilities and project financing floating rate debt and our derivative instruments as described in Notes 4, 5, 8 and 9.

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

Oil and Gas Exploration and Production

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

Directors.

We held a portfolio of swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on the over-the-counter swaps and options. These transactions were designated at inception as cash flow hedges, documented under accounting for derivatives and hedging, and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

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

We had the following derivatives and related balances (dollars in thousands) as of:

	December 31, 2011		December 31, 2010	
	Crude oil swaps/options	Natural gas swaps	Crude oil swaps/options	Natural gas swaps
Notional [(a)]	528,000	5,406,250	424,500	6,821,800
Maximum duration in years [(b)]	1.25	1.75	0.25	0.25
Derivative assets, current	$729	$8,010	$248	$7,675
Derivative assets, non-current	$771	$1,148	$19	$2,606
Derivative liabilities, current	$2,559	$—	$3,814	$—
Derivative liabilities, non-current	$811	$7	$1,301	$—
Pre-tax accumulated other comprehensive income (loss)	$(1,928)	$9,152	$(5,313)	$10,281
Revenue [(c)]	$58	$—	$465	$—

(a) Crude in Bbls, gas in MMBtu.
(b) Refers to the term of the derivative instrument. Assets and liabilities are classified as current/non-current based on the timing of the hedged transaction and the corresponding settlement of the derivative instrument.
(c) Represents the amortization of put premiums.

Based on December 31, 2011 market prices, a $5.6 million gain would be reclassified from AOCI during 2012. Estimated and actual realized gains or losses will likely change during future periods as market prices fluctuate.

Utilities

Our gas and electric utility customers are exposed to the effect of volatile natural gas prices; therefore, as allowed or required by state utility commissions, we have entered into 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.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held by our Utilities were as follows:

	December 31, 2011		December 31, 2010	
Natural gas (notional amounts in MMBtu)	Notional	Latest Expiration (months)	Notional	Latest Expiration (months)
Natural gas futures purchased	14,310,000	84	6,670,000	15
Natural gas options purchased	1,720,000	3	1,730,000	3
Natural gas basis swaps purchased	7,160,000	60	—	—

We had the following derivative balances related to the hedges in our Utilities (in thousands) as of:

	December 31, 2011	December 31, 2010
Derivative assets, current	$9,844	$4,787
Derivative assets, non-current	$52	$—
Derivative liabilities, current	$—	$—
Derivative liabilities, non-current	$7,156	$1,620
Net unrealized gain (loss) included in Regulatory assets or Regulatory liabilities	$17,556	$8,030
Cash collateral receivable (payable) included in derivative assets/liabilities	$19,416	$10,355
Option premium included in Derivative assets, current	$880	$842

Financing Activities

We are exposed to interest rate risk associated with fluctuations in interest rates on our variable interest rate debt. To manage this risk, 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.

Our interest rate swaps and related balances were as follows (dollars in thousands) as of:

	December 31, 2011		December 31, 2010	
	Interest Rate Swaps	De-designated Interest Rate Swaps (a)	Interest Rate Swaps	De-designated Interest Rate Swaps (a)
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	5.0	2.0	6.0	1.0
Derivative assets, current	$—	$—	$—	$—
Derivative assets, non-current	$—	$—	$—	$—
Derivative liabilities, current	$6,513	$75,295	$6,823	$53,980
Derivative liabilities, non-current	$20,363	$20,696	$14,976	$—
Pre-tax accumulated other comprehensive income (loss)	$(26,876)	$—	$(21,799)	$—
Pre-tax gain (loss) included in Consolidated Statements of Income	$—	$(42,010)	$—	$(15,193)
Cash collateral receivable (payable) included in Consolidated Balance Sheets	$—	$—	$—	$—

(a) The maximum term in years reflects the amended mandatory early termination dates. If the mandatory early termination dates are not extended, the swaps will require cash settlement based on the swap value of the termination date. When extended, de-designated swaps totaling $100.0 million terminate in 7 years and de-designated swaps totaling $150.0 million terminate in 17 years.

$50.0 million of our de-designated swaps 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 drops to BB+ or below by S&P, or Ba1 or below by Moody's, we would be required to post collateral for the entire amount of the swap's negative mark-to-market fair value.

Based on December 31, 2011 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $6.5 million would be reclassified from AOCI during the next 12 months. Estimated and realized losses will change during future periods as market interest rates change.

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 that includes senior executives that meets on a regular basis to review our credit activities and monitor compliance with our credit policies.

For 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.

As of December 31, 2011, our credit exposure (exclusive of retail customers of the regulated utilities) was concentrated primarily among investment grade companies. Credit exposure with non-investment grade or non-rated counterparties, was supported partially through letters of credit, prepayments or parental guarantees.

(4) FAIR VALUE MEASUREMENTS

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the placement within the fair value hierarchy levels.

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 (in thousands):

	As of December 31, 2011					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives - Oil and Gas	$—	$9,885	$768	$5	$—	$10,658
Commodity derivatives - Utilities	—	(9,520)	—	—	19,416	9,896
Money market fund	6,005	—	—	—	—	6,005
Total	$6,005	$365	$768	$5	$19,416	$26,559
Liabilities:						
Commodity derivatives - Oil and Gas	$—	$2,207	$1,165	$5	$—	$3,377
Commodity derivatives - Utilities	—	7,156	—	—	—	7,156
Interest rate swaps	—	122,867	—	—	—	122,867
Total	$—	$132,230	$1,165	$5	$—	$133,400

	As of December 31, 2010					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives - Oil and Gas	$—	$10,281	$266	$—	$—	$10,547
Commodity derivatives - Utilities	—	(5,568)	—	—	10,355	4,787
Money market fund	8,050	—	—	—	—	8,050
Total	$8,050	$4,713	$266	$—	$10,355	$23,384
Liabilities:						
Commodity derivatives - Oil and Gas	$—	$5,115	$—	$—	$—	$5,115
Commodity derivatives - Utilities	—	1,620	—	—	—	1,620
Interest rate swaps	—	75,779	—	—	—	75,779
Total	$—	$82,514	$—	$—	$—	$82,514

The following tables present the changes in level 3 recurring fair value (in thousands):

	Commodity Derivatives December 31, 2011	Commodity Derivatives December 31, 2010
Balance at beginning of year	$266	$381
Unrealized losses	(1,318)	(303)
Unrealized gains	751	188
Purchases	—	—
Issuances	—	—
Settlements	(96)	—
Transfers into level 3[(a)]	—	—
Transfers out of level 3 [(b)]	—	—
Balance at year end	$(397)	$266
Changes in unrealized (losses) gain relating to instruments still held as of year end	$(101)	$(302)

(a) Transfers into level 3 represent existing assets and liabilities that were previously categorized as a higher level for which the inputs became unobservable.

(b) 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 totaling $(0.6) million for the year ended December 31, 2011, are included in Operating revenues on the Consolidated Statements of Income while $0.1 million was recorded through AOCI on the Consolidated Balance Sheets for the year ended December 31, 2011. Commodity derivatives classified as level 3 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 period.

Fair Value Measures

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 on deposit in margin accounts at December 31, 2011 and 2010, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. 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 tables present the fair value and balance sheet classification of our derivative instruments as of December 31 (in thousands):

		December 31, 2011		December 31, 2010	
	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:					
Commodity derivatives	Derivative assets - current	$8,739	$—	$7,923	$—
Commodity derivatives	Derivative assets - non-current	1,919	—	2,625	—
Commodity derivatives	Derivative liabilities - current	—	2,559	—	3,814
Commodity derivatives	Derivative liabilities - non-current	—	818	—	1,301
Interest rate swaps	Derivative liabilities - current	—	6,513	—	6,822
Interest rate swaps	Derivative liabilities - non-current	—	20,363	—	14,976
		$10,658	$30,253	$10,548	$26,913
Derivatives not designated as hedges:					
Commodity derivatives	Derivative assets - current	$—	$9,572	$—	$5,567
Commodity derivatives	Derivative assets - non-current	—	(52)	—	—
Commodity derivatives	Derivative liabilities - current	—	—	—	—
Commodity derivatives	Derivative liabilities - non-current	—	7,156	—	1,621
Interest rate swaps	Derivative liabilities - current	—	75,295	—	53,980
Interest rate swaps	Derivative liabilities - non-current	—	20,696	—	—
		$—	$112,667	$—	$61,168

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.

Cash Flow Hedges

The impact of cash flow hedges on our Consolidated Statements of Income and Balance Sheets for the years ended are presented as follows (in thousands):

December 31, 2011

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	$(12,280)	Interest expense	$(7,664)		$—
Commodity derivatives	7,741	Revenue	5,487		—
Total	$(4,539)		$(2,177)		$—

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Derivatives in Cash Flow Hedging Relationships	December 31, 2010 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	$(13,527)	Interest expense	$(7,609)		$—
Commodity derivatives	15,456	Revenue	14,339		—
Total	$1,929		$6,730		$—

Derivatives in Cash Flow Hedging Relationships	December 31, 2009 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)	Revenue	23,102	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 years ended December 31 was as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	December 31, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income	December 31, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income	December 31, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swap	$(42,010)	$(15,193)	$55,653
Interest rate swaps - realized	Interest expense	(13,373)	(13,312)	(9,816)
		$(55,383)	$(28,505)	$45,837

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(5) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2011 Carrying Amount	Fair Value	2010 Carrying Amount	Fair Value
Cash and cash equivalents	$21,628	$21,628	$16,437	$16,437
Restricted cash	$9,254	$9,254	$4,260	$4,260
Total derivative assets	$20,554	$20,554	$15,335	$15,335
Total derivative liabilities	$133,400	$133,400	$82,514	$82,514
Notes payable	$345,000	$345,000	$249,000	$249,000
Long-term debt, including current maturities	$1,282,882	$1,464,289	$1,191,231	$1,290,519

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

Cash and Cash Equivalents

Included in cash and cash equivalents is cash and money market funds. The carrying amount approximates fair value due to the short maturity of these instruments.

Restricted Cash

Restricted cash accounts represent amounts required by Black Hills Wyoming project financing agreements. Of this total, $3.6 million was held in 30-day Guaranteed Investment Certificates at December 31, 2010.

Derivative Financial Instruments

These instruments are carried at fair value. 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 methods employed are included in Notes 3 and 4.

Notes Payable

The carrying amount of our notes payable 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.

(6) PROPERTY, PLANT AND EQUIPMENT

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

Utilities Group	2011		2010		Lives (in years)	
Electric Utilities	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Minimum	Maximum
Electric plant:						
Production	$707,498	49	$679,165	47	25	80
Electric transmission	170,146	49	154,936	47	40	65
Electric distribution	580,699	45	543,498	43	15	65
Plant acquisition adjustment	4,870	32	4,870	32	32	32
General	136,304	22	103,455	20	3	60
Capital lease - plant in service *	260,874	20	—	—	20	20
Construction work in progress	288,760		234,985			
Total electric plant	2,149,151		1,720,909			
Less accumulated depreciation and amortization	385,840		357,774			
Electric plant net of accumulated depreciation and amortization	$1,763,311		$1,363,135			

* Capital lease - plant in service represents the assets accounted for as a capital lease under the 20-year PPA between Colorado Electric and Black Hills Colorado IPP.

	2011		2010		Lives (in years)	
Gas Utilities	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Minimum	Maximum
Gas plant:						
Production	$35	37	$35	37	37	37
Gas transmission	15,543	53	15,704	48	53	57
Gas distribution	442,114	46	406,914	45	41	56
General	56,869	19	68,315	19	16	22
Construction work in progress	8,813		11,392			
Total gas plant	523,374		502,360			
Less accumulated depreciation and amortization	52,249		47,292			
Gas plant net of accumulated depreciation and amortization	$471,125		$455,068			

2011					Lives (in years)		
Non-regulated Energy	Property, Plant and Equipment	Construction Work in Progress	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Coal Mining	$140,683	$4,341	$73,777	$71,247	20	2	39
Oil and Gas	763,645	—	386,377	377,268	25	3	26
Power Generation	135,051	930	35,074	100,907	36	2	40
	$1,039,379	$5,271	$495,228	$549,422			

2010					Lives (in years)		
Non-regulated Energy	Property, Plant and Equipment	Construction Work in Progress	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Coal Mining	$135,157	$10,228	$65,465	$79,920	11	3	40
Oil and Gas	680,407	—	357,979	322,428	26	3	27
Power Generation	134,616	163,291	30,982	266,925	36	2	40
	$950,180	$173,519	$454,426	$669,273			

2011					Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$2,136	$4,705	$1,124	$5,717	6	2	30

2010					Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$4,039	$2,502	$2,283	$4,258	6	2	30

(7) JOINTLY OWNED FACILITIES

Oil and Gas

Through our BHEP subsidiary, we own a 44.7% non-operating interest in a natural gas processing facility (the Newcastle Gas Plant). The Newcastle Gas Plant gathers and processes gas, primarily from the Finn-Shurley Field in Wyoming. We receive our proportionate share of the Newcastle 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, 2011, our investment in the Newcastle Gas Plant included $4.3 million in plant and equipment which is included in Property, plant and equipment on the accompanying Consolidated Balance Sheets. This asset is included in the asset pool being depleted and therefore accumulated depreciation is not separated by asset. These items are included in the corresponding categories of revenue and expenses in the accompanying Consolidated Statements of Income.

Utility Plant

- Our subsidiary, Black Hills Power, owns a 20% interest in the Wyodak Plant, a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant. Black Hills Power receives its proportionate share of the Wyodak Plant's capacity and is committed to pay its proportionate share of its additions, replacements and operating and maintenance expenses. In addition to supplying Black Hills Power with coal for its share of the Wyodak Plant, our Coal Mining subsidiary, WRDC, supplies PacifiCorp's share of the coal to the Wyodak Plant under a long-term agreement. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC's coal reserves.

- Black Hills Power also owns a 35% interest in, and is the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the tie is 400 MW - 200 MW West to East and 200 MW from East to West. Black Hills Power is committed to pay its proportionate share of the additions and replacements to and operating and maintenance expenses of the transmission tie.

- Black Hills Power own 52% of its Wygen III coal-fired generation facility which commenced commercial operation on April 1, 2010. MDU and the City of Gillette each owns an undivided ownership interest in the Wygen III generation facility and are obligated to make payments for costs associated with administrative services and proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations.

- Black Hills Wyoming owns 76.5% of its Wygen I Plant while MEAN owns the remaining ownership percentage. MEAN is obligated to 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.

Our share of direct expenses for the jointly-owned utility facilities is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income.

At December 31, 2011, our interests in jointly-owned generating facilities and transmission systems were (dollars in thousands):

Plant in Service

		Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$109,007	$718	$46,104
Transmission Tie	19,648	—	4,061
Wygen I	104,854	880	23,046
Wygen III	129,791	249	5,328
	$363,300	$1,847	$78,539

(8) LONG-TERM DEBT

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

	Due Date	Interest Rate	2011	2010
Corporate				
Senior unsecured notes due 2013	May 15, 2013	6.5%	$225,000	$225,000
Unamortized discount on notes due 2013			(41)	(70)
Senior unsecured notes due 2014	May 15, 2014	9.0%	250,000	250,000
Senior unsecured notes due 2020	July 15, 2020	5.88%	200,000	200,000
Long-term term loan [(a)]	September 30, 2013	1.69%	100,000	—
Total Corporate Debt			774,959	674,930
Electric Utilities				
First Mortgage Bonds due 2032	August 15, 2032	7.23%	75,000	75,000
First Mortgage Bonds due 2039	November 1, 2039	6.13%	180,000	180,000
Unamortized discount on First Mortgage Bonds due 2039			(115)	(119)
Pollution control revenue bonds due 2014	October 1, 2014	4.80%	6,450	6,450
Pollution control revenue bonds due 2024	October 1, 2024	5.35%	12,200	12,200
First Mortgage Bonds due 2037	November 20, 2037	6.67%	110,000	110,000
Industrial development revenue bonds due 2021, variable rate [(a)]	September 1, 2021	0.14%	7,000	7,000
Industrial development revenue bonds due 2027, variable rate [(a)]	March 1, 2027	0.14%	10,000	10,000
Series 94A Debt [(a)]	June 1, 2024	3.00%	2,855	2,855
Other long-term debt	May 12, 2012	13.66%	72	234
Total Electric Utilities			403,462	403,620
Power Generation				
Black Hills Wyoming project financing, variable rate [(a)]	December 9, 2016	3.66%	104,461	112,681
Total long-term debt			1,282,882	1,191,231
Less current maturities			2,473	5,181
Net long-term debt			$1,280,409	$1,186,050

(a) Variable interest rates, rates presented are as of December 31, 2011.

Scheduled maturities of long-term debt, excluding amortization of premiums or discounts, for future years are (in thousands):

2012	$2,473
2013	$328,973
2014	$262,473
2015	$6,964
2016	$85,101
Thereafter	$597,054

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, 2011.

Substantially all of the tangible utility property of Black Hills Power and Cheyenne Light is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of Black Hills Power and Cheyenne Light may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. The first mortgage bonds issued by Black Hills Power and Cheyenne Light are either currently not callable or are subject to make-whole provisions which would eliminate any economic benefit for us to call the bonds.

Debt Offering

In July 2010, pursuant to a public offering, we issued $200.0 million aggregate principal of senior unsecured notes due July 15, 2020. The notes were priced at par and carry a fixed interest rate of 5.88%. We received proceeds of $198.7 million, net of underwriting fees. Deferred financing costs are being amortized over the term of the debt. Amortization of deferred financing costs is included in Interest expense.

Long-term Term Loan

Our $100.0 million term loan (the "Loan") with J.P. Morgan and Union Bank was extended through September 30, 2013. The cost of borrowings under the Loan was based on a spread of 1.375% over LIBOR (1.69% at December 31, 2011). The proceeds were used to reduce borrowings on the Revolving Credit Facility. The covenants are substantially the same as the Revolving Credit Facility.

Amortization Expense

Our deferred financing costs and associated amortization expense included in Interest expense on the accompanying Consolidated Statements of Income were as follows (in thousands):

	Deferred Financing Costs Remaining on Balance Sheet at	Amortization Expense for the years ended December 31,		
	December 31, 2011	2011	2010	2009
Senior unsecured notes due 2013	$309	$218	$218	$218
Senior unsecured notes due 2014	$1,097	$462	$462	$289
Senior unsecured notes due 2020	$1,428	$167	$77	$—
First mortgage bonds due 2023	$684	$33	$33	$33
First mortgage bonds due 2039	$2,113	$76	$76	$12
First mortgage bonds due 2037	$797	$31	$31	$31
Black Hills Wyoming project financing due 2016	$4,214	$1,012	$1,036	$60
Other	$816	$70	$74	$67

(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 requirements. At December 31, 2011, we were in compliance with all of these financial covenants. None of our facilities or debt securities contain default provisions pertaining to our credit ratings.

We had the following short-term debt outstanding as of the Consolidated Balance Sheet dates (in thousands):

	As of December 31, 2011		As of December 31, 2010	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$195,000	$43,700	$149,000	$46,865
Term Loan 2011	—	—	100,000	—
Term Loan 2012	150,000	—	—	—
Total	$345,000	$43,700	$249,000	$46,865

Revolving Credit Facility

Our $500.0 million Revolving Credit Facility expiring April 14, 2013 contained an accordion feature which allowed us, with the consent of the administrative agent, to increase the capacity of the facility to $600.0 million and was used for the issuance of letters of credit, to fund working capital needs and other corporate purposes. Borrowings were available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit was determined based upon our credit ratings. At current year-end credit ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 1.75%, 2.75% and 2.75%, respectively at December 31, 2011. The facility contained a commitment fee to be charged on the unused amount of the Revolving Credit Facility. Based upon current year-end credit ratings, the fee was 0.5%. On February 1, 2012, we entered into a new Revolving Credit Facility replacing the prior Revolving Credit Facility. See Note 25 for additional information.

Deferred financing costs are being amortized over the term of the Revolving Credit Facility and are included in Interest expense on the accompanying Consolidated Statements of Income as follows (in thousands):

	Deferred Financing Costs Remaining on Balance Sheet as of December 31, 2011	Amortization Expense for the years ended December 31, 2011	2010	2009
Revolving Credit Facility	$1,497	$1,891	$1,340	$495

The Revolving Credit Facility includes the following covenants that we must comply with at the end of each quarter (dollars, in thousands). We were in compliance with these covenants as of December 31, 2011.

	Actual	Covenant Requirement
Consolidated net worth	$1,209,336	$884,131
Recourse leverage ratio	58.5%	65.0%

Corporate Term Loans

In June 2011, we entered into a $150.0 million unsecured, single draw, term loan with CoBank, the Bank of Nova Scotia and U.S. Bank due on June 24, 2012. The cost of borrowing under the loan is based on a spread of 1.25% over

LIBOR (1.56% at December 31, 2011). The covenants are substantially the same as those included in the Revolving Credit Facility and we were in compliance with these covenants as of December 31, 2011.

(10) ASSET RETIREMENT OBLIGATIONS

Accounting standards for asset retirement obligations associated with long-lived assets require that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The 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 tables present the details of ARO which are included on the accompanying Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	12/31/10	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates *	12/31/11
Oil and Gas	$21,663	$43	$(627)	$1,343	$—	$22,422
Coal Mining	17,560	—	—	1,123	(1,525)	17,158
Electric Utilities	3,039	—	—	25	—	3,064
Gas Utilities	255	—	—	15	—	270
Total	$42,517	$43	$(627)	$2,506	$(1,525)	$42,914

	12/31/09	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates *	12/31/10
Oil and Gas	$21,233	$570	$(2,078)	$1,280	$658	$21,663
Coal Mining	15,285	18,094	(15,207)	1,246	(1,858)	17,560
Electric Utilities	2,904	—	—	135	—	3,039
Gas Utilities	241	—	—	14	—	255
Total	$39,663	$18,664	$(17,285)	$2,675	$(1,200)	$42,517

* The Revisions to Prior Estimates reflects the change in the estimated liability for final reclamation adjusted for inflation, discount rate and market risk premium.

We also have legally required 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 Issuance

On November 10, 2010, we entered into an Equity Forward Agreement with J.P. Morgan in connection with a public offering of 4,000,000 shares of Black Hills Corporation common stock. Subsequently, the underwriters exercised the over-allotment option to purchase 413,519 additional shares under the same terms as the original Forward Equity Agreement. We settled the equity forward instrument on November 1, 2011 by physically delivering 4,413,519 shares of common stock in return for proceeds of $119.6 million.

Equity Compensation Plans

Our 2005 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 961,476 shares available to grant at December 31, 2011.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of December 31, 2011, total unrecognized compensation expense related to non-vested stock awards was $7.1 million and is expected to be recognized over a weighted-average period of 1.8 years. Stock-based compensation expense included in Operations and maintenance on the accompanying Consolidated Statements of Income was as follow (in thousands):

	2011	2010	2009
Stock-based compensation expense	$5,643	$5,637	$3,908

Stock Options

We have granted options with an option exercise price equal to the fair market value of the stock on the day of the grant. The options granted vest proportionately over 3 years and expire 10 years after the grant date.

A summary of the status of the stock options at December 31, 2011 was as follows:

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
	(in thousands)		(in years)	(in thousands)
Balance at beginning of period	235	$ 32.92		
Granted [(a)]	99	32.04		
Forfeited/canceled	(6)	—		
Expired	(31)	53.51		
Exercised	(33)	30.32		
Balance at end of period	264	$ 30.50	4.5	$859
Exercisable at end of period	165	$ 29.57		

(a) The grant date fair value of the 2011 awards was $5.80 based on a Black-Scholes option pricing model. Assumptions used to estimate the fair value were a 2.6% risk free interest rate, 29.0% expected price volatility, 4.6% expected dividend yield and a 7 year expected life.

The table below provides details of our option plans (in thousands):

	2011	2010	2009
Summary of Stock Options			
Unrecognized compensation expense	$479	$—	$—
Intrinsic value of options exercised [(a)]	$94	$234	$255
Net cash received from exercise of options	$1,009	$1,034	$1,740
Tax benefit realized from exercise of shares [(b)]	$33	$82	$89

(a) The intrinsic value represents the amount by which the market price of the stock on the date of exercise exceeded the exercise price of the option.
(b) The tax benefit realized from the exercise of shares granted was recorded as an increase in equity.

As of December 31, 2011, the unrecognized compensation expense related to non-vested stock options that is expected to be recognized over a weighted-average period of 2.4 years.

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 over three years, contingent on continued employment. Compensation expense related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock and non-vested restricted stock units at December 31, 2011 was as follows:

	Restricted Stock and Stock Units	Weighted-Average Grant Date Fair Value
	(in thousands)	
Restricted Stock and Restricted Stock Units balance at beginning of period	270	$27.78
Granted	139	30.33
Vested	(113)	28.43
Forfeited	(18)	27.36
Restricted Stock and Restricted Stock Units balance at end of period	278	$28.82

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 was as follows:

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested (in thousands)
2011	$30.33	$3,211
2010	$27.30	$2,212
2009	$26.76	$1,799

As of December 31, 2011, there was $4.7 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 1.8 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based plan. Performance shares are awarded based on our total shareholder return over designated performance periods as measured against a selected peer group and can range from 0% to 175% of target. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria.

The performance awards are paid 50% 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 $1.9 million at December 31, 2011 would be reclassified as a liability.

Outstanding performance periods at December 31 were as follows (shares in thousands):

Grant Date	Performance Period	Target Grant of Shares
January 1, 2009	January 1, 2009 - December 31, 2011	73
January 1, 2010	January 1, 2010 - December 31, 2012	71
January 1, 2011	January 1, 2011 - December 31, 2013	67

A summary of the status of the Performance Share Plan at December 31 was as follows:

	Equity Portion		Liability Portion	
	Shares (in thousands)	Weighted-Average Grant Date Fair Value	Shares (in thousands)	Weighted-Average December 31, 2011 Fair Value
Performance Shares balance at beginning of period	87	$ 29.47	87	
Granted	34	25.92	34	
Forfeited	(3)	25.77	(3)	
Vested	(12)	46.00	(12)	
Performance Shares balance at end of period	106	$ 26.47	106	$ 20.89

The grant date fair values for the performance shares granted in 2011, 2010 and 2009 were determined by Monte Carlo simulation using a blended volatility of 30%, 31% and 39%, 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 was as follows:

	Weighted Average Grant Date Fair Value
December 31, 2011	$25.92
December 31, 2010	$24.26
December 31, 2009	$29.20

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, 2008 to December 31, 2010	2011	—	$—	$—
January 1, 2007 to December 31, 2009	2010	—	$—	$—
January 1, 2006 to December 31, 2008	2009	—	$—	$—

On January 25, 2012, the Compensation Committee of our Board of Directors determined that the plan criteria for the January 1, 2009 through December 31, 2011 performance period was not met. As a result, the payout for this performance period will be $0.0 million.

As of December 31, 2011, there was $1.9 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.6 years.

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. We are issuing new shares.

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A summary of the Dividend Reinvestment and Stock Purchase Plan was as follows (shares in thousands):

	2011	2010
Shares Issued	103	106
Weighted Average Price	$31.23	$29.57
Unissued Shares Available at December 31	453	190

Other Plans

We issued 14,111 fully-vested shares of common stock with an intrinsic value of $0.4 million in the year ended December 31, 2011 to certain key employees under the Short-term Annual Incentive Plan, a performance-based plan. The payout was fully accrued at December 31, 2010. We issued 9,625 and 47,331 shares of common stock in 2010 and 2009, respectively, under the Short-term Annual Incentive Plan. In addition, we will issue common stock with an intrinsic value of approximately $0.1 million in 2012 for the 2011 Short-term Annual Incentive Plan.

Dividend Restrictions

Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. See Note 9 for further information on our credit facilities. As of December 31, 2011, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at December 31, 2011:

- 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. Covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. In addition to the restrictions described above, each state in which we conduct utility operations imposes restrictions on affiliate transactions, including inter-company loans. Additionally, 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 be subject to further restrictions under the Federal Power Act. As of December 31, 2011, the restricted net assets at our Electric and Gas Utilities were approximately $61.5 million.

- Pursuant to a covenant in the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted assets of $100.0 million. In addition, Black Hills Wyoming holds $9.3 million of restricted cash in accordance with project financing requirements. Black Hills Non-regulated Holdings is the parent of Black Hills Electric Generation, which is the parent of Black Hills Wyoming.

(12) IMPAIRMENT OF LONG-LIVED ASSETS

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.

(13) OPERATING LEASES

We have entered into lease agreements for vehicle, equipment and office facilities. Rental expense incurred under these operating leases, including month to month leases, for the years ended December 31 was as follows (in thousands):

	2011	2010	2009
Rent expense	$6,125	$4,219	$3,939

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

2012	$2,799
2013	2,398
2014	2,376
2015	1,912
2016	1,403
Thereafter	3,610
	$14,498

(14) INCOME TAXES

Income tax expense (benefit) from continuing operations for the years ended December 31 was (in thousands):

	2011	2010	2009
Current:			
Current federal income tax expense (benefit)	$(14,539)	$678	$(12,351)
Current state income tax expense (benefit)	(837)	4,137	(408)
	(15,376)	4,815	(12,759)
Deferred:			
Deferred federal income tax expense (benefit)	30,876	20,186	45,912
Deferred state income tax expense (benefit)	2,970	(2,495)	66
Tax credit amortization expense (benefit)	(246)	(337)	(368)
	33,600	17,354	45,610
Total income tax expense (benefit)	$18,224	$22,169	$32,851

Tax planning allowed us to defer approximately $185.0 million of income taxes related to the IPP Transaction. In the third quarter of 2010, we reached an agreement with the Appeals Division of the IRS that resulted in a decrease of that amount to approximately $125.0 million. The decrease represents the downward adjustment to tax depreciation allowed on certain assets sold, which resulted in a decrease to the gain realized on the sale of those assets and ultimately a decrease in deferred taxes. The remaining deferred amount relating to the IPP Transaction and the Aquila Transaction continues to be subject to IRS review.

The temporary differences, which gave rise to the net deferred tax liability, for the years ended December 31, were as follows (in thousands):

	2011	2010
Deferred tax assets, current:		
Asset valuation reserves	$2,605	$1,448
Mining development and oil exploration	614	594
Unbilled revenue	—	—
Employee benefits	8,175	3,899
Items of other comprehensive income (loss)	2,858	3,076
Derivative fair value adjustments	33,824	19,304
Deferred costs	97	342
Other deferred tax assets, current	4,493	5,607
Total deferred tax assets, current	52,666	34,270
Deferred tax liabilities, current:		
Asset valuation reserves	—	(312)
Prepaid expenses	(2,442)	(2,431)
Derivative fair value adjustments	(362)	(327)
Items of other comprehensive income (loss)	(3,035)	(2,754)
Deferred costs	(6,508)	(4,621)
Other deferred tax liabilities, current	(3,117)	(3,161)
Total deferred tax liabilities, current	(15,464)	(13,606)
Net deferred tax asset, current	$37,202	$20,664
Deferred tax assets, non-current:		
Employee benefits	$14,313	$11,533
Regulatory liabilities	40,642	23,910
Deferred revenue	225	273
Deferred costs	—	—
State net operating loss (net of valuation allowance)	11,538	9,507
Items of other comprehensive income	33,540	22,306
Foreign tax credit carryover	2,801	3,352
Net operating loss	195,834	63,779
Asset impairment	47,033	48,092
Derivative fair value adjustment	5,275	3,038
Other deferred tax assets, non-current	9,453	11,076
Total deferred tax assets, non-current	360,654	196,866
Deferred tax liabilities, non-current:		
Accelerated depreciation, amortization and other plant-related differences	(508,261)	(314,513)
Regulatory assets	(23,498)	(16,050)
Mining development and oil exploration	(94,334)	(99,709)
Deferred costs	(9,155)	(17,615)
Derivative fair value adjustments	—	—
Items of other comprehensive income	(2,054)	(4,402)
State deferred tax liability	(14,611)	(11,477)
Other deferred tax liabilities, non-current	(9,729)	(8,942)
Total deferred tax liabilities, non-current	(661,642)	(472,708)

Net deferred tax liability, net, non-current	$(300,988)	$(275,842)
Net deferred tax liability	$(263,786)	$(255,178)

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The following table reconciles the change in the net deferred income tax liability from December 31, 2010 to December 31, 2011 to deferred income tax expense (in thousands):

	2011	2010
Net increase (decrease) in net deferred income tax liability for the year	$8,608	$414
Deferred taxes associated with other comprehensive loss (income)	2,259	1,915
Deferred taxes related to net operating loss from acquisition	—	(312)
Deferred taxes related to regulatory assets and liabilities	22,962	25,511
Deferred taxes related to acquisition	—	(784)
Deferred taxes associated with property basis differences	(14)	(10,121)
Other net deferred income tax	(215)	731
Deferred income tax expense for the period	$33,600	$17,354

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

	2011	2010	2009
Federal statutory rate	35.0%	35.0%	35.0%
State income tax (net of federal tax effect)	1.8	1.1	(0.3)
Amortization of excess deferred and investment tax credits	(0.5)	(0.4)	(0.3)
Percentage depletion in excess of cost	(2.5)	(1.7)	(0.8)
Equity AFUDC	(0.5)	(1.0)	(1.7)
Tax credits	—	(3.2)	—
Accounting for uncertain tax positions adjustment	2.8	1.2	(2.1)
Flow-through adjustments *	(4.5)	(4.6)	—
Other tax differences	(0.5)	(0.4)	(0.3)
	31.1%	26.0%	29.5%

* The flow-through adjustments relate primarily to an accounting method change for tax purposes that was filed with the 2008 tax return and for which consent was received from the IRS in September 2009. The effect of the change allows us to take a current tax deduction for repair costs that were previously capitalized for tax purposes. These costs will continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and we flowed the tax benefit through to our customers in the form of lower rates as a result of a rate case settlement that occurred during 2010. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. Due to this regulatory treatment, we recorded an income tax benefit that was attributable to the 2008 through 2010 tax years. For years prior to 2008, we did not record a regulatory asset for the repairs deduction as the tax benefit was not flowed through to customers.

At December 31, 2011, we have federal and state NOL carryforwards of $534.8 million and $413.6 million, respectively, which will expire at various dates as follows (in thousands):

Expiration Years	Net Operating Loss Carryforward
2014-2019	$9,306
2020-2025	$48,229
2026-2031	$890,861

As of December 31, 2011, the previously recorded valuation allowance against the federal NOL carryforwards was reduced to zero by netting it against the deferred tax asset for acquired NOL carryforwards that are subject to limitation under the Internal Revenue Code. We believe that such adjustment is a more accurate depiction of the acquired NOLs expected to be ultimately utilized within the prescribed carryforward period. We had a $0.8 million valuation allowance against the state NOL carry forwards. Ultimate usage of these NOLs depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOLs, the offsetting amount will affect tax expense.

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

	Changes in Uncertain Tax Positions
Beginning balance at January 1, 2009	$120,022
Additions for prior year tax positions	5,752
Reductions for prior year tax positions	(18,686)
Additions for current year tax positions	—
Settlements	—
Ending balance at December 31, 2009	107,088
Additions for prior year tax positions	19,592
Reductions for prior year tax positions	(76,545)
Additions for current year tax positions	—
Settlements	—
Ending balance at December 31, 2010	50,135
Additions for prior year tax positions	2,725
Reductions for prior year tax positions	(3,533)
Additions for current year tax positions	—
Settlements	—
Ending balance at December 31, 2011	$49,327

	2011	2010	2009
Uncertain tax positions	$49,327	$50,135	$107,088
Income tax refund receivable related to uncertain tax positions above	—	—	(59,136)
Net liability for uncertain tax positions	$49,327	$50,135	$47,952

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $1.1 million.

We recognized the following interest expense (benefit), included in Income tax (expense) benefit on the accompanying Consolidated Statements of Income, for the years ended December 31 as follows (in thousands):

	2011	2010	2009
Interest expense (income) included in Income tax (expense) benefit	$1,400	$2,300	$1,200

We had approximately $4.5 million and $3.1 million accrued for interest payable associated with income taxes at December 31, 2011 and 2010, respectively.

We file income tax returns with the IRS, various state jurisdictions and Canada. We are currently under examination by the IRS for the 2007 through 2009 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, 2012.

Excess foreign tax credits have been generated and are available to offset United States federal income taxes. At December 31, 2011, we had the following remaining foreign tax credit carryforwards (in thousands):

Foreign Tax Credit Carryforward	Expiration Year
$26	2014
$694	2015
$24	2016
$1,301	2017
$214	2020
$542	2021

(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):

2011	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Benefit plan liability adjustments - net gains (losses)	$(11,744)	$4,135	$(7,609)
Benefit plan liability adjustments - prior service (costs)	(501)	176	(325)
Fair value adjustment of derivatives designated as cash flow hedges	(4,539)	1,708	(2,831)
Reclassification adjustments of cash flow hedges settled and included in net income (loss)	2,177	(709)	1,468
Other comprehensive income (loss)	$(14,607)	$5,310	$(9,297)

2010	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Benefit plan liability adjustments - net gains (losses)	$(1,981)	$674	$(1,307)
Benefit plan liability adjustments - prior service (costs)	(325)	111	(214)
Fair value adjustment of derivatives designated as cash flow hedges	1,972	(636)	1,336
Reclassification adjustments of cash flow hedges settled and included in net income (loss)	(6,730)	2,498	(4,232)
Other comprehensive income (loss)	$(7,064)	$2,647	$(4,417)

2009	Pre-tax Amount	Tax (Expense) Benefit Plans	Net-of-tax Amount
Benefit plan liability adjustments - net gains (losses)	$(2,313)	$812	$(1,501)
Benefit plan liability adjustments - prior service (costs)	9,202	(3,231)	5,971
Benefit plan liability adjustments - transition obligations	33	(12)	21
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 (loss)	19,810	(7,201)	12,609

Other comprehensive income (loss)	$(710)	$329	$(381)

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

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Amount from Equity-method Investees	Total
As of December 31, 2009	$(9,462)	$(9,636)	$(66)	$(19,164)
Other comprehensive income (loss)	(2,975)	(1,506)	64	(4,417)
As of December 31, 2010	$(12,437)	$(11,142)	$(2)	$(23,581)
Other comprehensive income (loss)	(1,363)	(7,934)	—	(9,297)
As of December 31, 2011	$(13,800)	$(19,076)	$(2)	$(32,878)

(16) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,	2011 (in thousands)	2010	2009
Non-cash investing and financing activities-			
Property, plant and equipment acquired with accrued liabilities	$37,529	$48,879	$24,571
Capitalized asset retirement costs	$1,525	$1,858	$6,027
Refunding bond issuance — Industrial Development Revenue Bonds	$—	$—	$17,000
Cash (paid) refunded during the period for-			
Interest (net of amount capitalized)	$(103,110)	$(101,947)	$(69,317)
Income taxes, net	$9,854	$9,384	$17,117

(17) BUSINESS SEGMENTS INFORMATION

Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. All of our operations and assets are located within the United States.

In January 2012, we entered into a definitive agreement to sell our Energy Marketing segment, which resulted in this segment being reported as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the reclassification of this segment to discontinued operations on a consistent basis. Indirect corporate costs and inter-segment interest expenses related to Enserco that have not been reclassified to discontinued operations in accordance with GAAP have been reclassified to our Corporate segment. For further information see Note 23.

Detail for our segments as of and for the year ended December 31 was as follows (in thousands):

	2011	2010
Total assets		
Utilities:		
Electric Utilities [(a)]	$2,254,914	$1,834,019
Gas Utilities	746,444	722,287
Non-regulated Energy:		
Oil and Gas	425,970	349,991
Power Generation [(a)]	129,121	293,334
Coal Mining	88,704	96,962
Corporate	141,079	100,681
Discontinued Operations	340,851	314,235
Total assets	$4,127,083	$3,711,509

(a) The PPA under which the new generation facility was constructed at our Pueblo Airport Generation site by Black Hills Colorado IPP to support Colorado Electric customers is accounted for as a capital lease. Therefore, assets previously recorded at Power Generation are now accounted for at Colorado Electric under accounting for a capital lease.

	2011	2010
Capital expenditures and asset acquisitions		
Utilities:		
Electric Utilities	$173,078	$232,466
Gas Utilities	43,954	51,363
Non-regulated Energy:		
Oil and Gas	89,672	40,345
Power Generation	98,927	148,191
Coal Mining	10,438	17,053
Corporate	13,279	7,182
Total capital expenditures and asset acquisitions of continuing operations[(a)]	429,348	496,600
Total capital expenditures of discontinued operations	2,359	390
Total capital expenditures and asset acquisitions	$431,707	$496,990

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

	2011	2010
Property, plant and equipment		
Utilities:		
Electric Utilities [(a)]	$2,149,151	$1,720,909
Gas Utilities	523,374	502,360
Non-regulated Energy:		
Oil and Gas	763,645	680,407
Power Generation [(a)]	135,981	297,907
Coal Mining	145,024	145,385
Corporate	6,841	6,541
Total property, plant and equipment	$3,724,016	$3,353,509

(a) The PPA under which the new generation facility was constructed at our Pueblo Airport Generation site by Black Hills Colorado IPP to support Colorado Electric customers is accounted for as a capital lease. Therefore, assets previously recorded at Power Generation are now accounted for at Colorado Electric under accounting for a capital lease.

Year ended December 31, 2011	Consolidating Income Statement Electric Utilities (in millions)	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Intercompany Eliminations	Total
Revenue	$600,935	$554,584	$4,059	$32,802	$79,808	$—	$—	$1,272,188
Intercompany revenue	13,396	—	27,613	34,090	—	192,250	(267,349)	—
Fuel, purchased power and cost of gas sold	310,352	331,961	—	—	—	97	(67,421)	574,989
Gross margin	303,979	222,623	31,672	66,892	79,808	192,153	(199,928)	697,199
Operations and maintenance	142,815	121,980	16,538	56,617	41,380	170,947	(174,908)	375,369
Gain on sale of operating assets (a)	(768)	—	—	—	—	1	767	—
Depreciation, depletion and amortization	52,475	24,307	4,199	18,670	35,690	11,205	(10,955)	135,591
Operating income (loss)	109,457	76,336	10,935	(8,395)	2,738	10,000	(14,832)	186,239
Interest expense	(53,770)	(31,621)	(8,903)	(9)	(5,896)	(93,314)	102,130	(91,383)
Unrealized (loss) gain on interest rate swaps, net	—	—	—	—	—	(42,010)	—	(42,010)
Interest income	14,794	5,645	1,529	3,897	2	64,299	(88,149)	2,017
Other income (expense), net	481	217	1,094	2,192	(216)	46,510	(46,552)	3,726
Income tax benefit (expense)	(23,271)	(16,408)	(1,644)	1,891	1,651	19,289	268	(18,224)
Income (loss) from continuing operations	$47,691	$34,169	$3,011	$(424)	$(1,721)	$4,774	$(47,135)	$40,365

(a) Electric Utilities includes a gain on sale of assets to a related party which was eliminated in consolidation.

Year ended December 31, 2010	Consolidating Income Statement Electric Utilities (in millions)	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Intercompany Eliminations	Total
Revenue (a)	$554,617	$550,707	$4,297	$31,285	$74,164	$—	$—	$1,215,070
Intercompany revenue (a)	15,397	—	26,052	26,557	—	140,756	(204,141)	4,621
Fuel, purchased power and cost of gas sold (a)	292,811	333,717	—	—	—	150	(59,711)	566,967
Gross margin	277,203	216,990	30,349	57,842	74,164	140,606	(144,430)	652,724
Operations and maintenance	136,873	125,447	16,210	34,028	39,299	129,641	(129,879)	351,619
Gain on sale of operating assets (b)	(6,238)	(2,683)	—	—	—	—	—	(8,921)
Depreciation, depletion and amortization	47,276	25,258	4,466	19,083	30,283	9,469	(9,229)	126,606
Operating income (loss)	99,292	68,968	9,673	4,731	4,582	1,496	(5,322)	183,420
Interest expense	(43,855)	(28,927)	(9,303)	(177)	(5,380)	(75,406)	72,442	(90,606)
	—	—	—	—	—	(15,193)	—	(15,193)

Unrealized (loss) gain on interest rate swaps, net								
Interest income	6,812	1,472	1,193	3,357	8	54,472	(66,773)	541
Other income (expense), net	3,215	47	854	2,149	722	28,768	(28,607)	7,148
Income tax benefit (expense)	(18,012)	(14,449)	(266)	(2,379)	425	12,512	—	(22,169)
Income (loss) from continuing operations	$47,452	$27,111	$2,151	$7,681	$357	$6,649	$(28,260)	$63,141

(a) Revenue has been restated to reflect eliminations of intercompany activities previously not eliminated (see Note 1).

(b) Electric Utilities includes gain on sale to the City of Gillette of an ownership interest in the Wygen III power generation facility. Gas Utilities includes a gain on the sale of operating assets at Nebraska Gas (see Note 22).

Year ended December 31, 2009	Consolidating Income Statement Electric Utilities (in millions)	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Intercompany Eliminations	Total
Revenue [(a)]	$511,326	$580,312	$4,445	$31,459	$70,684	$—	$—	$1,198,226
Intercompany revenue [(a)]	9,439	—	26,130	27,031	—	97,010	(159,124)	486
Fuel, purchased power and cost of gas sold [(a)]	281,009	371,716	—	—	—	1	(57,486)	595,240
Gross margin	239,756	208,596	30,575	58,490	70,684	97,009	(101,638)	603,472
Operations and maintenance	125,150	123,296	12,631	40,312	40,224	95,184	(95,748)	341,049
Gain on sale of operating assets [(b)]	—	—	(25,971)	—	—	—	—	(25,971)
Depreciation, depletion and amortization	43,638	30,090	3,860	13,123	29,680	6,933	(6,386)	120,938
Impairment of long-lived assets [(c)]	—	—	—	—	43,301	—	—	43,301
Operating income	70,968	55,210	40,055	5,055	(42,521)	(5,108)	496	124,155
Interest expense	(34,830)	(17,364)	(11,244)	(24)	(4,683)	(47,522)	32,414	(83,253)
Unrealized (loss) gain on interest rate swaps, net	—	—	—	—	—	55,653	—	55,653
Interest income	1,818	264	1,856	1,476	10	27,531	(32,032)	923
Other income (expense), net	7,869	(285)	1,091	3,475	350	12,201	(12,059)	12,642
Income tax benefit (expense)	(13,126)	(13,453)	(11,097)	(3,234)	21,016	(12,957)	—	(32,851)
Income (loss) from continuing operations	$32,699	$24,372	$20,661	$6,748	$(25,828)	$29,798	$(11,181)	$77,269

(a) Revenue has been restated to reflect eliminations of intercompany activities previously not eliminated (see Note 1).
(b) Includes a gain on sale to MEAN of an ownership interest in the Wygen I power generation facility (see Note 22).
(c) As a result of lower natural gas prices at March 31, 2009, we recorded a non-cash ceiling test impairment of oil and gas assets (see Note 12).

(18) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

We sponsor a 401(k) retirement savings plan (the 401(k) Plan). Participants in the 401(k) Plan may elect to invest a portion of their eligible compensation to the 401(k) Plan up to the maximum amounts established by the IRS. The 401(k) Plan provides employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis. The 401(k) Plan provides a Company Matching Contribution for all participants and for certain eligible participants a Company Retirement Contribution based on the participant's age and years of service. Vesting of all Company contributions ranges from immediate vesting to graduated vesting at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

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. The measurement date for all plans is December 31. As of December 31, 2011, the funded status of our Defined Benefit Pension Plan was $104.0 million; the funded status of our Non-Qualified Defined Benefit Retirement Plan was $30.0 million; and the funded status of our Non-Pension Defined Benefit Postretirement Plan was $46.0 million.

Defined Benefit Pension Plan

We have three non-contributory defined benefit pension plans (the Pension Plans). As of January 1, 2012, all Pension Plans have been frozen to new employees and certain employees who did not meet age and service based criteria at the time the Plans were frozen. The benefits for the plans are based on years of service and calculations of average earnings during a specific time period prior to retirement.

In 2011, the Cheyenne Light Pension Plan was amended to freeze the benefits of certain bargaining unit employees. This amendment was effective as of January 1, 2012.

Our Pension Plan 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.

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. Our Pension Plan 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.

The expected long-term rate of return for equity investments was 8.75% and 9.25% for the 2011 and 2010 plan years, respectively.

Plan Assets

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

	2011		2010	
Equity	64	%	65	%
Real estate	3		3	
Fixed income	32		31	
Cash	1		1	
Total	100	%	100	%

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 and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to a graded vesting schedule at 20% per year over 5 years and are not funded by the Company.

Plan Assets

We fund the NQDC on a cash basis as benefits are paid; therefore, assets of the plan are $0.0 million.

Non-pension Defined Benefit Postretirement Plans

We sponsor retiree healthcare plans (the Healthcare Plans) for all employees who meet certain age and service requirements at retirement and who are entitled to postretirement healthcare benefits. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. We may amend or change the plans periodically. A portion of the Healthcare Plan is pre-funded via VEBAs. It has been determined that the post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy.

Plan Assets

We fund the Healthcare Plans on a cash basis as benefits are paid. The Black Hills Energy Plan provides for partial pre-funding via VEBAs. Assets 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.

Plan Contributions

Contributions to the Healthcare Plans and the Supplemental Plans are made in the form of benefit payments. Contributions to our employee benefit plans were as follows (in thousands):

	2011	2010
Defined Benefit Plans		
Defined Benefit Pension Plans	$11,050	$30,015
Non-Pension Defined Benefit Postretirement Healthcare Plans	$4,963	$5,198
Supplemental Non-Qualified Defined Benefit Plans	$956	$894

	2011	2010
Defined Contribution Plan		

Company Retirement Contribution	$2,440	$2,022
Matching contributions - Defined Contribution Plans	$8,916	$7,900

We expect to make contributions to our employee benefit plans as follows (in thousands):

	2012
Defined Benefit Plans	
Defined Benefit Pension Plans	$12,483
Non-Pension Defined Benefit Postretirement Healthcare Plans	$4,250
Supplemental Non-Qualified Defined Benefit Plans	$1,110

Fair Value Measurements

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 (in thousands):

Defined Benefit Pension Plans	December 31, 2011			
	Level 1	Level 2	Level 3	Total
Money Market Fund	$70	$—	$—	$70
Registered Investment Companies - Equity	23,498	—	—	23,498
Registered Investment Companies - Fixed Income	23,422	—	—	23,422
103-12 Investment Entities - Equity	—	10,329	—	10,329
Common Collective Trust - Money Market	—	25	—	25
Common Collective Trust - Equity	—	103,004	—	103,004
Common Collective Trust - Fixed Income	—	48,024	—	48,024
Common Collective Trust - Real Estate	—	—	7,042	7,042
Structured Products	—	3,884	—	3,884
Insurance Contracts	—	2,424	—	2,424
Total investments measured at fair value	$46,990	$167,690	$7,042	$221,722

Defined Benefit Pension Plans	December 31, 2010			
	Level 1	Level 2	Level 3	Total
Money Market Fund	$—	$—	$—	$—
Registered Investment Companies - Equity	27,070	—	—	27,070
Registered Investment Companies - Fixed Income	27,544	—	—	27,544
103-12 Investment Entities - Equity	—	11,246	—	11,246
Common Collective Trust - Money Market	—	174	—	174
Common Collective Trust - Equity	—	106,786	—	106,786
Common Collective Trust - Fixed Income	—	39,121	—	39,121
Common Collective Trust - Real Estate	—	—	6,126	6,126
Insurance Contracts	—	2,097	—	2,097
Total investments measured at fair value	$54,614	$159,424	$6,126	$220,164

Non-pension Defined Benefit Postretirement Plans	December 31, 2011			
	Level 1	Level 2	Level 3	Total
Common Collective Trust	$—	$4,319	$—	$4,319
Total investments measured at fair value	$—	$4,319	$—	$4,319

Non-pension Defined Benefit Postretirement Plan	December 31, 2010			
	Level 1	Level 2	Level 3	Total
Common Collective Trust	$—	$4,564	$—	$4,564
Total investments measured at fair value	$—	$4,564	$—	$4,564

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):

	2011	2010
Balance, beginning of period	$6,126	$5,844
Unrealized gain (loss)	917	282
Balance, end of period	$7,043	$6,126

Additional information about plan assets, including methods and assumption used to estimate the fair value of these assets, is as follows:

Registered Investment Companies: Investments are valued at the closing price reported on the active market on which the individual securities are traded.
103-12 Investment Entities: The trustee determines the value of the pooled trust fund and the units thereof in U.S. Dollars as of (i) each daily valuation date, and (ii) each other day designated by mutual agreement between the trustee and the investment manager. As of each valuation date, the trustee shall determine the total value of the assets of the pooled trust fund, including the value of any interest accrued or dividends payable with respect thereto, shall be determined and securities valued as of the close of business in the applicable trading market coinciding with or next preceding the close of business on the New York Stock Exchange.
Common Collective Trust: The Pension Plan owns units of the Common Collective Trust funds that they are utilizing in their portfolio. The value of each unit of any fund as of any valuation date shall be determined by calculating the total value of such fund's assets as of the close of business on such valuation date, deducting its total liabilities as of such time and date, and then dividing the so-determined net asset value of such fund by the total number of units of such fund outstanding the date of valuation.
Insurance Contract: These investments are valued on a cash basis on any given valuation date.
Structured Products: Investments are created through the process of financial engineering, (that is, by combining underlying securities like equity, bonds, or indices with derivatives). The value of derivative securities, such as options, forwards and swaps is determined by (respectively, derives from) the prices of the underlying securities.

Other Plan Information

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, components of the net periodic expense and elements of accumulated other comprehensive income (in thousands):

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2011	2010	2011	2010	2011	2010
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$280,623	$256,400	$24,725	$21,611	$46,304	$46,396
Service cost	5,421	6,131	1,028	685	1,498	1,509
Interest cost	14,929	15,091	1,298	1,284	2,168	2,446
Actuarial (gain) loss	36,543	13,663	4,128	2,039	3,017	961
Amendments	—	261	—	—	(160)	(2,239)
Benefits paid	(11,178)	(9,949)	(956)	(894)	(4,963)	(5,198)
Plan curtailment reduction	(394)	(974)	—	—	—	—
Medicare Part D accrued	—	—	—	—	188	559
Plan participants' contributions	—	—	—	—	2,089	1,870
Projected benefit obligation at end of year	$325,944	$280,623	$30,223	$24,725	$50,141	$46,304

A reconciliation of the fair value of Plan assets was as follows (in thousands):

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans [(a)]	
	2011	2010	2011	2010	2011	2010
Beginning market value of plan assets	$220,164	$176,503	$—	$—	$4,564	$4,717
Investment income	1,686	23,595	—	—	1	1
Employer contributions	11,050	30,015	—	—	2,087	2,493
Retiree contributions	—	—	—	—	1,366	1,205
Benefits paid	(11,178)	(9,949)	—	—	(3,713)	(3,847)
Plan administrative expenses	—	—	—	—	14	(5)
Ending market value of plan assets	$221,722	$220,164	$—	$—	$4,319	$4,564

(a) Asset of VEBA

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Amounts recognized in the Consolidated Balance Sheet consist of (in thousands):

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2011	2010	2011	2010	2011	2010
Regulatory asset	$93,423	$54,202	$—	$—	$9,161	$7,896
Current liability	$—	$—	$1,116	$943	$3,522	$2,999
Non-current liability	$104,214	$60,451	$30,953	$23,782	$42,313	$38,561
Regulatory liability	$—	$—	$—	$—	$590	$1,050

Accumulated Benefit Obligation

(in thousands)	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2011	2010	2011	2010	2011	2010
Accumulated benefit obligation - Black Hills Corporation	$106,800	$90,301	$23,023	$19,153	$14,313	$12,101
Accumulated benefit obligation - Black Hills Energy	184,345	160,217	446	454	25,842	25,080
Accumulated benefit obligation - Cheyenne Light	5,731	4,462	—	—	9,986	9,121
	$296,876	$254,980	$23,469	$19,607	$50,141	$46,302

Components of Net Periodic Expense

(in thousands)	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Service cost	$5,421	$6,131	$7,587	$1,028	$685	$469	$1,498	$1,509	$1,060
Interest cost	14,929	15,091	14,715	1,298	1,284	1,376	2,168	2,446	2,202
Expected return on assets	(16,955)	(14,493)	(14,281)	—	—	—	(164)	(208)	(226)
Amortization of prior service cost	99	99	127	3	3	1	(479)	(309)	(23)
Amortization of transition obligation	—	—	—	—	—	—	—	—	60
Recognized net actuarial loss (gain)	4,540	3,126	2,720	510	285	589	677	636	(27)
Curtailment expense	13	57	322	—	—	—	—	—	—
Net periodic expense	$8,047	$10,011	$11,190	$2,839	$2,257	$2,435	$3,700	$4,074	$3,046

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 were as follows (in thousands):

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2011	2010	2011	2010	2011	2010
Net (gain) loss	$11,472	$6,545	$6,894	$4,544	$2,556	$2,172
Prior service cost (gain)	98	121	12	14	(1,956)	(2,276)
Transition obligation	—	—	—	—	—	—
Total accumulated other comprehensive (income) loss	$11,570	$6,666	$6,906	$4,558	$600	$(104)

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 2012 are as follows (in thousands):

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Plans
Net loss	$6,560	$525	$577
Prior service cost	58	2	(325)
Transition obligation	—	—	—
Total net periodic benefit cost expected to be recognized during calendar year 2012	$6,618	$527	$252

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:	2011	2010	2009	2011	2010	2009	2011	2010	2009
Discount rate	4.65%	5.48%	6.03%	4.30%	4.95%	5.58%	4.42%	5.03%	5.68%
Rate of increase in compensation levels	3.77%	3.79%	4.20%	5.00%	5.00%	5.00%	N/A	N/A	N/A

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Weighted-average assumptions used to determine net periodic benefit cost for plan year:	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Discount rate:									
Black Hills Corporation	5.50 %	6.05 %	6.25 %	5.00 %	6.10 %	6.20 %	5.00 %	5.90 %	6.10 %
Black Hills Energy	5.40 %	6.00 %	6.25 %	4.40 %	5.05 %	5.00 %	4.60 %	5.15 %	6.10 %
Cheyenne Light	5.55 %	6.05 %	6.20 %	N/A	N/A	N/A	5.50 %	6.00 %	6.10 %
Expected long-term rate of return on assets*	7.75 %	8.00 %	8.50 %	N/A	N/A	N/A	4.00 %	5.00 %	5.00 %
Rate of increase in compensation levels	3.79 %	4.20 %	4.20 %	5.00 %	5.00 %	5.00 %	NA	NA	N/A

* The expected rate of return on plan assets changed to 7.25% for the calculation of the 2012 net periodic pension cost.

The healthcare benefit obligation was determined at December 31, 2011, using an initial healthcare trend rate of 9.01% trending down to an ultimate rate of 4.50% in 2028, and at December 31, 2010, using an initial healthcare trend rate of 9.51% trending down to an ultimate rate of 4.50% in 2027.

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 an increase or decrease to our healthcare trend rate for our Retiree Healthcare Plans (in thousands):

Change in Assumed Trend Rate	Impact on December 31, 2011 Accumulated Postretirement Benefit Obligation	Impact on 2011 Service and Interest Cost
Increase 1%	$2,720	$184
Decrease 1%	$(2,272)	$(150)

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

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plan	Non-Pension Defined Benefit Postretirement Plans
2012	$12,484	$1,110	$4,250
2013	$13,181	$1,090	$4,380
2014	$13,953	$1,280	$4,320
2015	$14,823	$1,290	$4,170
2016	$15,694	$1,370	$4,250
2017-2021	$93,852	$7,160	$21,950

(19) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

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

- Black Hills Power's PPA with PacifiCorp, expiring December 31, 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.

- Black Hills Power has a firm point-to-point transmission service agreement with PacifiCorp that expires December 31, 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp.

- Cheyenne Light's PPA with Duke Energy's Happy Jack wind site, expiring September 3, 2028, provides up to 30 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's PPA with Duke Energy's Silver Sage wind site, expiring September 30, 2029, for up to 30 MW of wind energy. Under a separate intercompany agreement, Cheyenne Light has agreed to sell 20 MW of energy from Silver Sage to Black Hills Power.

- Colorado Electric's PPA with PSCo expiring December 31, 2012, whereby Colorado Electric purchases 50 MW of economy energy.

- Colorado Electric's PPA with Cargill expiring December 31, 2013, whereby Colorado Electric purchases 50 MW of economy energy.

Costs under these power purchase contracts for the years ended December 31 were as follows (in thousands):

	2011	2010	2009
PPA with PacifiCorp	$12,515	$12,936	$11,862
PPA with PSCo [(a)]	$97,988	$110,575	$97,899
Transmission services agreement with PacifiCorp	$1,215	$1,215	$1,215
PPA with Happy Jack	$1,955	$2,815	$2,078
PPA with Silver Sage	$3,281	$1,723	$713

(a) This PPA with PSCo expired on December 31, 2011 and was replaced with the facilities constructed by Colorado Electric at our Pueblo Airport Generation site and the facilities constructed by Black Hills Colorado IPP to support a new PPA with Colorado Electric.

Other Supply Agreements

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.

Colorado Electric has a firm supply contract through December 31, 2013.

The following is a schedule of future minimum payments required under the power purchase, transmission services, coal and gas supply agreements (in thousands):

2012	$199,811
2013	$123,600
2014	$73,145
2015	$70,140
2016	$46,568
Thereafter	$202,779

Cheyenne Light's PPA for 60 MW of capacity and energy from Black Hills Wyoming's Wygen I generating facility expiring on December 31, 2022, includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership in the Wygen I facility. 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.

Long-Term Power Sales Agreements

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

- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU;

- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23 MW from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, Black Hills Power will also provide the City of Gillette their operating component of spinning reserves;

- Cheyenne Light has an agreement with Basin Electric whereby Cheyenne Light provides 40 MW of capacity and energy through March 31, 2013 and a separate agreement whereby Cheyenne Light will receive 40 MW of capacity and energy from Basin Electric through March 13, 2013. The agreements became effective March 14, 2011;

- Black Hills Power has a PPA with MEAN expiring April 1, 2015. Under this contract, MEAN purchases 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III; and

- Black Hills Power has a PPA with MEAN expiring May 31, 2023. This contract is unit-contingent on up to 10 MW from Neil Simpson II and up to 10 MW from Wygen III is based on the availability of these plants. The capacity purchase requirements decrease over the term of the agreement.

Related Party Lease

Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, provides 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. This PPA is accounted for as a capital lease whereby Colorado Electric, as lessee, has included the combined-cycle turbines as property, plant and equipment along with the related lease obligation and Black Hills Colorado IPP, as lessor, has recorded a lease receivable.

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 capitalized as part of the carrying amount of the long-lived asset in Property, plant and equipment. See Note 10 for additional information. The asset is depreciated over the appropriate time period. The amount of depreciation expense for the years ended December 31 was as follows (in thousands):

	2011	2010	2009
Depreciation expense on capitalized asset retirement costs	$5,212	$6,519	$1,993

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, 2011, cannot be reasonably determined and could have a material effect on the results of operations, financial position or 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.

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

Nature of Guarantee	Maximum Exposure at December 31, 2011	Year Expiring
Guarantees of payment obligations arising from commodity-related physical and financial transactions of Black Hills Utility Holdings (1)	$70,000	Ongoing
Guarantees for payment obligations arising from purchase contracts for four gas turbines for Black Hills Colorado IPP (2)	384	2012
Guarantees for payment obligations arising from purchase contracts for two gas turbines for Colorado Electric (3)	56	2012
Guarantee for payment obligations relating to a contract to construct 16 wind turbines at Colorado Electric (4)	33,264	January 15, 2013
Indemnification for subsidiary reclamation/surety bonds (5)	18,601	Ongoing
Guarantee for payment obligations arising from natural gas transportation, storage and services agreement for Black Hills Utility Holdings (6)	10,000	July 31, 2012
Guarantee for performance and payment obligation of Black Hills Utility Holdings for natural gas supply (7)	7,500	June 30, 2012
	$139,805	

(1) We have guaranteed some 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, Northern Natural Gas Company and 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.

(2) We have issued four guarantees to GE for payment obligations arising from contracts to purchase four LM6000 gas turbines for Black Hills Colorado IPP. These are continuous guarantees which will terminate upon settlement of all obligations.

(3) We have issued two guarantees 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 will terminate upon settlement of all obligations.

(4) We have issued a guarantee to Vestas-American Wind Technology, Inc. for the performance and payment obligations of Colorado Electric relating to the purchase of wind turbines for the Colorado Electric wind power generation project. This guarantee will remain in effect until satisfaction of Colorado Electric's contractual obligations.

(5) We have guarantees in place 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.

(6) We issued a guarantee to Colorado Interstate Gas Company for payment obligations of Black Hills Utility Holdings related to natural gas transportation, storage and services agreements.

(7) We issued a guarantee to Cross Timbers Energy Services for the performance and payment obligation of Black Hills Utility Holdings for natural gas supply purchase.

(21) OIL AND GAS RESERVES (Unaudited)

BHEP has operating and non-operating interests in 1,219 gross developed oil and gas wells in 9 states and holds leases on approximately 328,643 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):

	2011	2010	2009
Acquisition of properties:			
Proved	$673	$—	$—
Unproved	8,317	3,846	3,443
Exploration costs	44,384	8,159	5,962
Development costs	38,638	25,264	10,133
Asset retirement obligations incurred	43	1,228	623
Total costs incurred	$92,055	$38,497	$20,161

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, 2011, 2010 and 2009, and a reconciliation of the changes between these dates. These estimates are based on reserve reports by CG&A. 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.

	2011		2010		2009	
	Oil	Gas	Oil	Gas	Oil	Gas
	(in Mbbls of oil and MMcf of gas)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	5,940	95,456	5,274	87,660	5,185	154,432
Production [(a)]	(452)	(8,526)	(376)	(8,484)	(366)	(9,710)
Additions - acquisitions (sales)	(84)	—	(13)	(377)	—	—
Additions - extensions and discoveries	927	29,664	1,145	1,710	152	2,560
Revisions to previous estimates [(b)]	(108)	(20,690)	(90)	14,947	303	(59,622)
Balance at end of year	6,223	95,904	5,940	95,456	5,274	87,660
Proved developed reserves at end of year included above	4,830	71,867	4,434	67,656	4,274	74,911
Proved undeveloped reserves at the end of year included in above	1,393	24,037	1,506	27,800	1,000	12,749
NYMEX prices	$96.19	$4.12	$79.43	$4.38	$61.18	$3.87
Well-head reserve prices	$88.49	$3.59	$70.82	$3.45	$53.59	$2.52

(a) Production for reserve calculations does not include volumes for natural gas liquids (NGL's).

(b) Included in the total revisions are (23.6) Bcfe for dropped PUD locations due to five year aging of reserves which was offset by positive performance revisions of 2.3 Bcfe in various basins. Revisions due to cost and commodity pricing were less than 1% Bcfe.

Reserve additions totaled 35.2 Bcfe, replacing 119% of production. Additions resulted from drilling in the Williston, San Juan and Piceance basins. Drilling in Williston Basin (Bakken Shale) accounted for 7.0 Bcfe, San Juan (Mancos Shale) accounted for 11.1 Bcfe and Piceance (Mancos Shale) accounted for 16.5 Bcfe of the additions. Williston Basin drilling is planned through 2014. Capital spending in 2011 was increased to accommodate the Williston Bakken drilling and to evaluate the development potential of the San Juan and Piceance Mancos Shale under our leasehold. Additionally, exploratory investments were made in 2011 to develop future opportunities. Future capital spending rates are anticipated to dependent on product prices.

SEC regulations require that proved undeveloped locations meet the test of being developed within five years of being categorized as proved. Most of the revisions to previous estimates were due to five year aging of the proved undeveloped reserves in the Piceance Basin, Wind River Basin and Bear Paw Uplift and were removed from our proved reserves. Revisions were offset by positive revisions in the San Juan Basin of 1.7 Bcfe and some minor performance revisions in Williston Basin (0.4) Bcfe, Powder River Basin (0.7) Bcfe, Piceance 0.5 Bcfe and 1.2 Bcfe in other basins.

- 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. In 2011, we invested approximately $18.9 million to drill and develop 9 PUD locations from our 2010 inventory totaling approximately 4.7 Bcfe in proved developed reserve recognition. 100% of the PUD development in 2011 was in the Williston Basin which resulted in approximately 13 additional PUDs (4.6 net Bcfe) added to our year-end 2011 reserves. Additional PUDs were added in the Piceance (3 gross locations, 12.0 net Bcfe) and San Juan (2 gross locations, 7.5 net Bcfe) basins following 2011 drilling in those basins.

- Approximately 23.6 Bcfe were dropped from the proved reserves in 2011 due to five year aging of the PUDs. This drop was primarily in the Piceance (21.2 Bcfe, 17 gross locations, $34.7 million future investment), Bear Paw Uplift (0.5 Bcfe, 17 gross locations, $0.8 million future investment), and Wind River Basin (2.0 Bcfe, 25 gross locations, and $3.6 million future investment).

- As of December 31, 2011, PUD locations, proved reserves and future development costs associated with certain locations are as follows:

	As of December 31, 2011		
Basin	Proved Reserves (in Bcfe)	Gross PUD Locations	Future Development Costs (in millions)
Piceance	12.8	4	$26.7
Williston	10.5	33	46.3
Bear Paw Uplift	1.0	32	2.0
San Juan	8.1	3	15.1
	32.4	72	$90.1

- None of our PUD locations have been reflected in our reserves for five or more years. Consistent with the 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):

	2011	2010	2009
Unproved oil and gas properties	$28,656	$28,160	$29,351
Proved oil and gas properties	674,494	592,978	582,276
Gross capitalized costs	703,150	621,138	611,627
Accumulated depreciation, depletion and amortization and valuation allowances	(361,173)	(334,955)	(335,605)
Net capitalized costs	$341,977	$286,183	$276,022

Results of Operations

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

	2011	2010	2009
Revenue	$79,808	$74,164	$70,684
Production costs	23,820	21,922	21,653
Depreciation, depletion and amortization and valuation provisions*	34,415	29,013	72,338
Total costs	58,235	50,935	93,991
Results of operations from producing activities before tax	21,573	23,229	(23,307)
Income tax benefit (expense)	(7,442)	(8,014)	8,041
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$14,131	$15,215	$(15,266)

*Includes pre-tax ceiling test impairment charges of $43.3 million in 2009.

Unproved properties not subject to amortization at December 31, 2011, 2010 and 2009 consisted mainly of exploration cost on various existing work-in-progress projects as well as leasehold acquired through significant natural gas and oil property acquisitions and through direct purchases of leasehold. We capitalized approximately $0.9 million, $0.8 million and $0.3 million of interest during 2011, 2010 and 2009, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. We will continue to evaluate our unevaluated properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined. We expect the exploration cost listed below to be added to the cost pool the next year.
The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2011 and notes the year in which the associated costs were incurred (in thousands):

	2011	2010	2009	Prior	Total
Leasehold acquisition cost	$3,451	$3,442	$887	$17,119	$24,899
Exploration cost	16,745	—	—	—	16,745
Capitalized interest	291	404	55	3,006	3,756
Total	$20,487	$3,846	$942	$20,125	$45,400

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):

	2011	2010	2009
Future cash inflows	$931,637	$764,585	$519,867
Future production costs	(280,910)	(256,455)	(207,783)
Future development costs	(92,233)	(73,805)	(34,961)
Future income tax expense	(157,922)	(111,666)	(51,287)
Future net cash flows	400,572	322,659	225,836
10% annual discount for estimated timing of cash flows	(197,215)	(154,551)	(96,728)
Standardized measure of discounted future net cash flows	$203,357	$168,108	$129,108

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):

	2011	2010	2009
Standardized measure - beginning of year	$168,108	$129,108	$179,226
Sales and transfers of oil and gas produced, net of production costs	(52,914)	(40,282)	(26,836)
Net changes in prices and production costs	57,087	57,380	(40,786)
Extensions, discoveries and improved recovery, less related costs	31,179	17,076	3,324
Changes in future development costs	43,809	(17,125)	83,000
Development costs incurred during the period	18,940	4,975	4,620
Revisions of previous quantity estimates	(58,211)	27,513	(104,556)
Accretion of discount	19,655	13,434	19,596
Net change in income taxes	(23,283)	(23,233)	11,520
Purchases of reserves	—	—	—
Sales of reserves	(1,013)	(738)	—
Standardized measure - end of year	$203,357	$168,108	$129,108

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 due to performance. 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, and service availability.

(22) SALE OF OPERATING ASSETS

Sale of Operating Assets

Sale of Gas Assets

On March 1, 2010, Nebraska Gas sold assets to Metropolitan Utilities District as a result of annexation proceedings by the City of Omaha, Nebraska. Nebraska Gas received $6.1 million in cash and recognized a $2.7 million pre-tax gain on the sale.

Partial Sale of Wygen III to City of Gillette, WY

On July 14, 2010, Black Hills Power sold a 23% ownership interest in Wygen III to the City of Gillette for $62.0 million. The Participation Agreement provides that the City of Gillette will pay Black Hills Power for administrative services and share in the costs of operating the plant for the life of the facility. The estimated amount of net fixed assets sold totaled $55.8 million. Black Hills Power recognized a gain on the sale of $6.2 million.

Partial Sale of Wygen I to MEAN

On January 1, 2009, Black Hills Wyoming sold a 23.5% ownership interest in the Wygen I plant to MEAN 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.

Partial Sale of Wygen III to MDU

On April 9, 2009, Black Hills Power sold a 25% ownership interest in its Wygen III generation facility to MDU. At closing, MDU made a payment to us for its share of the costs to date on the ongoing construction of the facility. Proceeds of $32.8 million were received. MDU continued to reimburse Black Hills Power for its proportionate share of the total costs paid to complete the project.

(23) DISCONTINUED OPERATIONS

Results of operations for discontinued operations have been classified as Income 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 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 reclassification on a consistent basis.

Energy Marketing Segment

On January 18, 2012, we entered into a definitive agreement to sell all of the outstanding stock of our Energy Marketing segment, Enserco Energy Inc., to Twin Eagle. The transaction will be completed through a stock purchase agreement and certain other ancillary agreements. As consideration for the assets acquired (net of liabilities assumed), the purchase price to be paid by Twin Eagle will be calculated on the closing date. Net cash proceeds are expected to be approximately $160 million to $170 million, subject to working capital and other closing adjustments. Although actual results could differ materially from our expectations, after closing costs and other adjustments, the sales proceeds are expected to approximate book value which is not expected to result in a significant gain or loss. The transaction is expected to be completed by the end of the first quarter of 2012.

The accompanying consolidated financial statements have been reclassified to reflect Enserco, which represented our Energy Marketing segment, as discontinued operations.

Operating results of the Energy Marketing segment included in Discontinued operations on the accompanying Consolidated Statements of Income were as follows (in thousands):

	For the Years Ended		
	December 31, 2011	December 31, 2010	December 31, 2009
Revenue	$41,101	$27,999	$13,381
Pre-tax income from discontinued operations	14,838	8,673	1,950
Income tax (expense) benefit	(5,473)	(3,129)	(464)
Income from discontinued operations	$9,365	$5,544	$1,486

Total indirect corporate costs and inter-segment interest expenses previously allocated to Enserco were not reclassified to discontinued operations in accordance with GAAP and instead have been reclassified to our Corporate segment. An estimate of how these costs could have been allocated to segments other than Corporate is as follows (in thousands):

	Years Ended		
Business Segment	December 31, 2011	December 31, 2010	December 31, 2009
Electric Utilities	$1,613	$1,650	$1,666
Gas Utilities	1,043	1,092	1,177
Oil and Gas	407	435	538
Power Generation	228	233	231
Coal Mining	127	105	141
	$3,418	$3,515	$3,753

Total assets and liabilities of Enserco have been classified as Current assets of discontinued operations and Current liabilities of discontinued operations on the accompanying Consolidated Balance Sheets at December 31, 2011 and 2010. Net assets of the Energy Marketing segment included in Discontinued operations were as follows (in thousands):

	As of	
	December 31, 2011	December 31, 2010
Other current assets	$280,221	$257,082
Derivative assets, current and non-current	52,859	50,498
Property, plant and equipment, net	5,828	3,699
Goodwill	1,435	1,435
Other non-current assets	508	1,521
Other current liabilities	(132,951)	(152,602)
Derivative liabilities, current and non-current	(26,084)	(18,014)
Other non-current liabilities	(14,894)	(2,707)
Net assets	$166,922	$140,912

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 for our Energy Marketing Segment (in thousands):

	December 31, 2011					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives - Energy Marketing	$—	$789,537	$6,139	$(743,154)	$337	$52,859
Liabilities:						
Commodity derivatives - Energy Marketing	$—	$771,534	$5,411	$(743,154)	$(7,707)	$26,084

	December 31, 2010					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives - Energy Marketing	$—	$166,405	$7,976	$(122,639)	$(1,410)	$50,332
Foreign currency	—	166	—	—	—	166
Total	$—	$166,571	$7,976	$(122,639)	$(1,410)	$50,498
Liabilities:						
Commodity derivatives - Energy Marketing	$—	$143,537	$2,463	$(122,639)	$(5,368)	$17,993
Foreign currency	—	21	—	—	—	21
Total	$—	$143,558	$2,463	$(122,639)	$(5,368)	$18,014

The following tables set forth the roll forward of level 3 assets and liabilities that were accounted for at fair value on a recurring basis for our Energy Marketing Segment (in thousands):

	Commodity Derivatives December 31, 2011	Commodity Derivatives December 31, 2010
Balance at beginning of year	$5,513	$(937)
Unrealized losses	(8,631)	(2,525)
Unrealized gains	6,094	7,295
Settlements	(2,248)	(1,179)
Transfers in to level 3[(a)]	—	1,457
Transfers out of level 3[(b)]	—	1,402
Balance at year end	$728	$5,513
Changes in unrealized (losses) gains relating to instruments still held as of year end	$(825)	$1,078

(a) Transfers into level 3 represent existing assets and liabilities that were previously categorized as a higher level for which the inputs
became unobservable.
(b) 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.

The following tables set forth, by the location of our assets and liabilities that were accounted for at fair value on a recurring basis for our Energy Marketing Segment (in thousands):

		December 31, 2011		December 31, 2010	
	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:					
Commodity derivatives	Assets of discontinued operations	$—	$—	$10,952	$1,452
Commodity derivatives	Assets of discontinued operations	—	—	48	71
Commodity derivatives	Liabilities of discontinued operations	5,256	403	—	45
Commodity derivatives	Liabilities of discontinued operations	—	—	—	—
		$5,256	$403	$11,000	$1,568
Derivatives not designated as hedges:					
Commodity derivatives	Assets of discontinued operations	$55,413	$13,740	$142,013	$107,795
Commodity derivatives	Assets of discontinued operations	76,629	54,784	9,757	3,099
Commodity derivatives	Liabilities of discontinued operations	691,453	729,309	20,588	39,051
Commodity derivatives	Liabilities of discontinued operations	4,852	9,354	978	4,442
Foreign currency	Assets of discontinued operations	—	—	166	21
		$828,347	$807,187	$173,502	$154,408

IPP Transaction

In July 2008, we sold seven of our IPP generating facilities. Under the agreement, there were certain working capital adjustments and tax benefits of $2.4 million which were recorded in 2009 in Income (loss) from discontinued operations. For business segment reporting purposes, results were previously included in the Power Generation segment.

(24) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth select unaudited historical operating results and market data for each quarter of 2011 and 2010.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2011				
Revenue	$400,835	$260,649	$249,523	$361,181
Operating income	58,367	36,160	39,572	52,140
Income (loss) from continuing operations [(a)]	29,068	3,706	(11,163)	18,754
Income (loss) from discontinued operations	(2,158)	4,046	638	6,839
Net income (loss) available for common stock [(a)]	26,910	7,752	(10,525)	25,593
Income (loss) per share for continuing operations - basic	$0.74	$0.09	$(0.29)	$0.45
Income (loss) per share for discontinued operations - basic	(0.05)	0.11	0.02	0.16
Income (loss) per share - basic	$0.69	$0.20	$(0.27)	$0.61
Income (loss) per share for continuing operations - diluted	$0.73	$0.09	$(0.29)	$0.44
Income (loss) per share for discontinued operations - diluted	(0.05)	0.10	0.02	0.16
Income (loss) per share - diluted	$0.68	$0.19	$(0.27)	$0.60
Dividends paid per share	$0.365	$0.365	$0.365	$0.365
Common stock prices - High	$33.64	$34.85	$32.22	$34.47
Common stock prices - Low	$29.76	$28.12	$25.83	$29.10

(a) Includes unrealized mark-to-market gain (loss) for interest rate swaps of $3.6 million, $(5.1) million, $(24.9) million, and $(0.9) 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)			
2010				
Revenue [a]	$416,728	$247,443	$240,521	$314,999
Operating income [b]	$64,698	$27,170	$44,695	$46,857
Income (loss) from continuing operations [b] [c]	$28,705	$(10,688)	$10,493	$34,631
Income (loss) from discontinued operations	$2,729	$2,029	$1,897	$(1,111)
Net income (loss) available for common stock [b] [c]	$31,434	$(8,659)	$12,390	$33,520
Income (loss) per share, Basic:				
Earnings (loss) per share for continuing operations	$0.74	$(0.27)	$0.27	$0.89
Earnings (loss) per share for discontinued operations	0.07	0.05	0.05	(0.03)
Earnings (loss) per share - basic	$0.81	$(0.22)	$0.32	$0.86
Income (loss) per share, Diluted:				
Earnings (loss) per share for continuing operations	$0.74	$(0.27)	$0.27	$0.88
Earnings (loss) per share for discontinued operations	0.07	0.05	0.05	(0.03)
Earnings (loss) per share - diluted	$0.81	$(0.22)	$0.32	$0.85
Dividends paid per share	$0.36	$0.36	$0.36	$0.36
Common stock prices - High	$30.83	$34.49	$33.31	$33.42
Common stock prices - Low	$25.65	$27.34	$27.79	$29.32

(a) Revenue has been restated to reflect eliminations of intercompany activities previously not eliminated. See Note 1.

(b) Includes pre-tax gain on sale of operating assets of $2.7 million ($1.7 million after-tax) and $6.2 million ($4.1 million after-tax) in the first and third quarters, respectively.

(c) Includes unrealized mark-to-market income (loss) for interest rate swaps of $(2.0) million, $(16.2) million, $(8.9) million and $17.2 million after-tax in the first, second, third and fourth quarters, respectively.

(25) SUBSEQUENT EVENTS

Sale of Energy Marketing Segment

On January 18, 2012, we entered into a definitive agreement to sell the outstanding stock of Enserco, our Energy Marketing segment, to Twin Eagle Resource Management, LLC for expected net cash proceeds of approximately $160 million to $170 million, subject to working capital and other closing adjustments. The transaction is expected to be completed by the end of the first quarter of 2012. As a result, the Consolidated Financial Statements have been reclassified to reflect this business as a discontinued operation for all periods presented. See Note 23 for further details.

Revolving Credit Facility

On February 1, 2012, we entered into a new $500.0 million Revolving Credit Facility. The new Revolving Credit Facility, now expiring on February 1, 2017, remains at $500.0 million but contains an accordion feature which allows us, with the consent of the administrative agent, to increase the capacity of the facility to $750.0 million and can be used for the issuance of letters of credit, to fund working capital needs and for other corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The interest costs associated with letters of credit or borrowings under the agreement are determined based upon our credit ratings. At our current credit rating, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 0.5%, 1.5% and 1.5%. The facility contains a commitment fee to be charged on the unused amount of the Revolving Credit Facility which is 0.25% based on current credit ratings.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of 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, 2011 and concluded that, because of the material weakness in our internal control over financial reporting related to accounting for income taxes discussed below, our disclosure controls and procedures were not effective as of December 31, 2011. Additional review, evaluation and oversight have been undertaken to ensure our consolidated financial statements were prepared in accordance with generally accepted accounting principles and as a result, our management, including our Chief Executive Officer and Chief Financial Officer, have concluded that the consolidated financial statements in this Form 10-K fairly present in all material respects our financial position, results of operations and cash flows for the periods presented in conformity with accounting principles generally accepted in the United States.

Management's Report on Internal Control over Financial Reporting

Management of Black Hills Corporation is 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, 2011, 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, including consideration of the internal control deficiencies discussed below, we have concluded that our internal control over financial reporting was not effective as of December 31, 2011. Specifically, we determined that the following internal control deficiencies when considered in the aggregate constitute a material weakness in internal control over financial reporting related to accounting for income taxes.

- The assessment of the impact of certain non-routine transactions on the accuracy of our year-end income tax provision was not effective.

- Tax resources were not sufficient to effectively prepare and review the analysis of tax accounts.
- Communication between the tax department and the Controller organization was not effective to ensure income tax accounting consequences were adequately considered.

A material weakness is a deficiency, or combination of deficiencies, that result in a reasonable possibility that a material misstatement of a company's annual or interim financial statements will not be prevented or detected on a timely basis. While the above noted deficiencies did not result in a material misstatement to our annual consolidated financial statements, these deficiencies could if not remediated, result in a material misstatement of future consolidated financial statements.

Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of December 31, 2011. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

Black Hills Corporation

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2011, 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.

While no changes to our internal controls over financial reporting are noted during the quarter ended December 31, 2011, a material weakness was identified as set forth in "Management's Report on Internal Control over Financial Reporting" above. Management believes the measures described below will remediate the identified control deficiencies and enhance our internal controls over financial reporting:

- Increase tax department resources to ensure completion and documentation of a more thorough analysis that supports our calculation of the effective tax rate and valuation of deferred tax assets and liabilities.

- Implement formal periodic meetings among the Chief Financial Officer, Controller and the tax department to ensure adequate consideration of items that may impact income tax accounting.

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 Black Hills Corporation's and subsidiaries' (the "Company's") internal control over financial reporting as of December 31, 2011, 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 that 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.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following internal control deficiencies, when considered in aggregate, have been identified as a material weakness and included in management's assessment: (1) the assessment of the impact of certain non-routine transactions on the accuracy of the year-end income tax provision was not effective, (2) tax resources were not sufficient to effectively prepare and review the analysis of tax accounts, and (3) communication between the tax department and the Controller organization was not effective to ensure income tax accounting consequences were adequately considered. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2011, of the Company and this report does not affect our report on such financial statements and financial statement schedules.

In our opinion, because of the effect of the material weakness identified above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2011, 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, 2011, of the Company and our report dated February 29, 2012, expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 29, 2012

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this item with respect to directors and information required by Items 401, 405, 406, 407(c)(3), 407(d)(4) and 407(d)(5) of Regulation S-K, is set forth in the Proxy Statement for our 2012 Annual Meeting of Shareholders, which is incorporated herein by reference.

Executive Officers

David R. Emery, age 49, 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 22 years of experience with the Company.

Scott A. Buchholz, age 50, has been our Senior Vice President — Chief Information Officer since the closing 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 59, 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.

Linden R. Evans, age 49, 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 from December 2003 to October 2004, and served as our Associate Counsel from May 2001 to December 2003. Mr. Evans has 10 years of experience with the Company.

Steven J. Helmers, age 55, has been our Senior Vice President, General Counsel and Chief Compliance Officer since January 2008. He served as our Senior Vice President, General Counsel since January 2004 and our Senior Vice President, General Counsel and Corporate Secretary from 2001 to 2004. Mr. Helmers has 11 years of experience with the Company.

Robert A. Myers, age 54, has been our Senior Vice President — Chief Human Resource Officer 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 31 years of service in key human resources leadership roles.

Lynnette K. Wilson, age 52, has been our Senior Vice President — Communications and Investor Relations since the closing 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 11 years.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is set forth in the Proxy Statement for our 2012 Annual Meeting of Shareholders, which is incorporated herein by reference.

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 set forth in the Proxy Statement for our 2012 Annual Meeting of Shareholders, which is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2011 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	437,665 [(1)]	$30.50 [(1)]	961,476 [(2)]
Equity compensation plans not approved by security holders	—	$—	—
Total	437,665	$30.50	961,476

(1) Includes 173,989 full value awards outstanding as of December 31, 2011, 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, 278,155 shares of unvested restricted stock were outstanding as of December 31, 2011, which are not included in the above table because they have already been issued.

(2) 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 set forth in the Proxy Statement for our 2012 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is set forth in the Proxy Statement for our 2012 Annual Meeting to Shareholders, which is incorporated herein by reference.

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, 2011, 2010 and 2009

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,	2011	2010	2009
	(in thousands)		
Revenue	$—	$—	$—
Operating expenses	772	735	524
Operating income (loss)	(772)	(735)	(524)
Other income (expense):			
Equity income (loss) in earnings of subsidiaries	87,150	88,627	57,394
Interest expense	(15,229)	(14,985)	(17,786)
Unrealized (loss) gain on interest rate swaps, net	(42,010)	(15,193)	55,653
Interest income	3	22	10
Other income (expense), net	(42)	34	28
Total other income (expense)	29,872	58,505	95,299
Income (loss) from continuing operations before income taxes	29,100	57,770	94,775
Income tax benefit (expense)	20,630	10,915	(13,025)
Income (loss) from continuing operations	49,730	68,685	81,750
Loss from discontinued operations	—	—	(195)
Net income (loss) available for common stock	$49,730	$68,685	$81,555

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

BLACK HILLS CORPORATION (PARENT COMPANY)
CONDENSED BALANCE SHEETS

At December 31,	2011	2010
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$3,114	$219
Accounts receivable — affiliates, current	1,445	869
Notes receivable — affiliates, current	453,216	201,497
Deferred income tax assets, net, current	36,951	21,137
Other current assets	15,831	15,173
Total current assets	510,557	238,895
Property and Equipment	1,135	—
Investments in subsidiaries	1,339,024	1,269,123
Notes receivable — affiliate, non-current	575,000	575,000
Deferred income tax assets, net, non-current	29,454	44,587
Other long-term assets	4,834	3,889
Total other assets, non-current	609,288	623,476
TOTAL ASSETS	$2,460,004	$2,131,494
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable -- affiliate, current	$5,202	$1,613
Derivative liabilities, current	78,502	57,343
Notes payable	345,000	249,000
Notes payable — affiliate, current	1,754	25,232
Other current liabilities	12,070	12,109
Total current liabilities	442,528	345,297
Derivative liabilities, non-current	31,368	7,360