BLACK HILLS CORP /SD/
Form 10-Q
November 04, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2010.

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission File Number 001-31303

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

Registrant's telephone number (605) 721-1700

Former name, former address, and former fiscal year if changed since last report
NONE

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 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 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

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Class	Outstanding at October 29, 2010
Common stock, $1.00 par value	39,248,927 shares

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GLOSSARY OF TERMS AND ABBREVIATIONS
AND ACCOUNTING STANDARDS

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

Acquisition Facility	Our $1.0 billion single-draw, senior unsecured facility from which a $383 million draw was used to provide part of the funding for the Aquila Transaction
AFUDC	Allowance for Funds Used During Construction
Annexation Agreement	Agreement with the City of Pueblo, Colorado under which the City of Pueblo annexed the property on which Colorado Electric and Colorado IPP are constructing their generation facilities
AOCI	Accumulated Other Comprehensive Income (Loss)
Aquila	Aquila, Inc.
ASC	Accounting Standards Codification
ASC 310-10-50	ASC 310-10-50, "Disclosures About the Credit Quality of Financing Receivables and the Allowance for Credit Losses"
ASC 810-10-15	ASC 810-10-15, "Consolidation of Variable Interest Entities"
ASC 820	ASC 820, "Fair Value Measurements and Disclosures"
ASC 932-10-S99	ASC 932-10-S99, "Extractive Activities - Oil and Gas, SEC Materials"
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
BHCRPP	Black Hills Corporation Risk Policies and Procedures
BHEP	Black Hills Exploration and Production, Inc., representing our Oil and Gas segment, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Blackbox	Blackbox settlement with the utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders
Black Hills Electric Generation	Black Hills Electric Generation, LLC, representing our Power Generation segment, a direct wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business activities of Black Hills Utility Holdings
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of the Company that was formerly known as Black Hills Energy, Inc.
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Service Company	Black Hills Service Company, a direct wholly-owned subsidiary of the Company
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
CFTC	Commodities Futures and Trading Commission
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company
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
Colorado IPP	Black Hills Colorado IPP, a direct wholly-owned subsidiary of Black Hills Electric Generation
Corporate Credit Facility	Our $525 million credit facility which was terminated on April 15, 2010
CPUC	Colorado Public Utilities Commission

De-designated interest rate swaps	The $250.0 million notional amount interest rate swaps that were originally designated as cash flow hedges under accounting for derivatives and hedges but subsequently de-designated in December 2008
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	U.S. Department of Energy
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
EDF	EDF Trading North America, LLC
Enserco	Enserco Energy Inc., representing our Energy Marketing segment, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse Gases
GSRS	Gas Safety and Reliability Surcharge
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	Our July 11, 2008 sale of seven of our IPP plants to affiliates of Hastings Fund Management Ltd and IIF BH Investment LLC
IRS	Internal Revenue Service
IUB	Iowa Utilities Board
JPB	Consolidated Wyoming Municipalities Electric Power System Joint Powers Board
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	One thousand standard cubic feet
Mcfe	One thousand standard cubic feet equivalent
MDU	MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MMBtu	One million British thermal units
MW	Megawatt
MWh	Megawatt-hour
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
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
OCA	Office of Consumer Advocate
Participation Agreement	Amended and Restated Wygen III Participation Agreement dated July 14, 2010 between BHP, MDU and JPB, which includes JPB as partial owner of Wygen III
PGA	Purchase Gas Adjustment
PPA	Power Purchase Agreement
PPACA	Patient Protection and Affordability Care Act
Revolving Credit Facility	Our $500 million three-year revolving credit facility which commenced on April 15, 2010 and expires on April 14, 2013
SDPUC	South Dakota Public Utilities Commission

SEC	United States Securities and Exchange Commission
SEC Release No. 33-8995	SEC Release No. 33-8995, "Modernization of Oil and Gas Reporting"
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands, except per share amounts)			
Operating revenues	$264,355	$225,799	$977,978	$921,090
Operating expenses:				
Fuel and purchased power	103,250	94,120	468,937	467,309
Operations and maintenance	39,719	35,431	121,861	115,226
Gain on sale of operating assets	(6,238)	—	(8,921)	(25,971)
Administrative and general	38,709	38,344	124,201	117,817
Depreciation, depletion and amortization	30,036	29,824	88,691	92,535
Taxes, other than income taxes	10,937	11,171	34,730	34,680
Impairment of long-lived assets	—	—	—	43,301
Total operating expenses	216,413	208,890	829,499	844,897
Operating income	47,942	16,909	148,479	76,193
Other income (expense):				
Interest expense	(24,279)	(20,691)	(68,667)	(62,930)
Interest rate swap - unrealized (loss) gain	(13,710)	(8,694)	(41,663)	37,775
Interest income	199	327	529	1,184
Allowance for funds used during construction - equity	375	2,598	2,663	5,284
Other income, net	539	2,142	2,225	3,779
Total other income (expenses)	(36,876)	(24,318)	(104,913)	(14,908)
Income (loss) from continuing operations before equity in earnings (loss) of unconsolidated subsidiaries and income taxes	11,066	(7,409)	43,566	61,285
Equity in earnings (loss) of unconsolidated subsidiaries	(137)	119	1,471	1,368
Income tax benefit (expense)	1,461	3,437	(9,872)	(16,300)
Income (loss) from continuing operations	12,390	(3,853)	35,165	46,353
Income from discontinued operations, net of taxes	—	1,673	—	2,439
Net income (loss)	$12,390	$(2,180)	$35,165	$48,792
Weighted average common shares outstanding:				
Basic	38,933	38,643	38,895	38,584
Diluted	39,133	38,643	39,052	38,646

Earnings (loss) per share:				
Basic-				
Continuing operations	$0.32	$(0.10)	$0.90	$1.20
Discontinued operations	—	0.04	—	0.06
Total earnings (loss) per share - basic	$0.32	$(0.06)	$0.90	$1.26
Diluted-				
Continuing operations	$0.32	$(0.10)	$0.90	$1.20
Discontinued operations	—	0.04	—	0.06
Total earnings (loss) per share - diluted	$0.32	$(0.06)	$0.90	$1.26
Dividends paid per share of common stock	$0.360	$0.355	$1.080	$1.065

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)

	September 30, 2010	December 31, 2009	September 30, 2009
	(in thousands, except share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$58,975	$112,901	$137,681
Restricted cash	17,082	17,502	6
Accounts receivables, net	234,480	274,489	208,563
Materials, supplies and fuel	145,251	123,322	99,952
Derivative assets, current	71,688	37,747	56,951
Income tax receivable, net	25,156	2,031	—
Deferred income tax asset, current	15,073	4,523	13,221
Regulatory assets, current	55,941	25,085	12,775
Other current assets	20,932	27,270	31,565
Total current assets	644,578	624,870	560,714
Investments	17,981	18,524	19,462
Property, plant and equipment	3,243,641	2,975,993	2,891,102
Less accumulated depreciation and depletion	(880,938)	(815,263)	(795,378)
Total property, plant and equipment, net	2,362,703	2,160,730	2,095,724
Other assets:			
Goodwill	353,734	353,734	353,734
Intangible assets, net	4,129	4,309	4,725
Derivative assets, non-current	12,762	3,777	5,438
Regulatory assets, non-current	124,134	135,578	120,677
Other assets, non-current	20,216	16,176	7,861
Total other assets	514,975	513,574	492,435
TOTAL ASSETS	$3,540,237	$3,317,698	$3,168,335

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Continued)
(unaudited)

	September 30, 2010	December 31, 2009	September 30, 2009
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$201,072	$229,352	$184,208
Accrued liabilities	166,977	151,504	150,042
Derivative liabilities, current	108,318	57,166	68,634
Accrued income taxes, net	—	—	15,734
Regulatory liabilities, current	12,368	7,092	30,120
Notes payable	145,000	164,500	350,500
Current maturities of long-term debt	5,314	35,245	32,091
Total current liabilities	639,049	644,859	831,329
Long-term debt, net of current maturities	1,188,293	1,015,912	719,215
Deferred credits and other liabilities:			
Deferred income tax liability, non-current	279,315	262,034	228,715
Derivative liabilities, non-current	25,892	11,999	27,824
Regulatory liabilities, non-current	79,393	42,458	40,168
Benefit plan liabilities	122,178	140,671	135,027
Other deferred credits and other liabilities	125,710	114,928	123,527
Total deferred credits and other liabilities	632,488	572,090	555,261
Stockholders' equity:			
Common stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized;			
Issued 39,243,257; 38,977,526 and 38,872,925 shares, respectively	39,243	38,978	38,873
Additional paid-in capital	597,108	591,390	588,556
Retained earnings	466,691	473,857	454,907
Treasury stock at cost – 7,905; 8,834 and 7,605 shares, respectively	(226)	(224)	(197)
Accumulated other comprehensive loss	(22,409)	(19,164)	(19,609)
Total stockholders' equity	1,080,407	1,084,837	1,062,530
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,540,237	$3,317,698	$3,168,335

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

	Nine Months Ended September 30,	
	2010	2009
Operating activities:	(in thousands)	
Net income	$35,165	$48,792
Income from discontinued operations, net of taxes	—	(2,439)
Income from continuing operations	35,165	46,353
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	88,691	92,535
Impairment of long-lived assets	—	43,301
Derivative fair value adjustments	(10,690)	19,647
Gain on sale of operating assets	(8,921)	(25,971)
Stock compensation	2,908	1,747
Unrealized mark-to-market loss (gain) on interest rate swaps	41,663	(37,775)
Deferred income taxes	32,366	5,164
Equity in (earnings) loss of unconsolidated subsidiaries	(1,471)	(1,368)
Allowance for funds used during construction - equity	(2,663)	(5,284)
Employee benefit plans	12,214	12,807
Other non-cash adjustments	6,663	(126)
Change in operating assets and liabilities:		
Materials, supplies and fuel	(40,344)	23,210
Accounts receivable and other current assets	8,754	157,118
Accounts payable and other current liabilities	(21,295)	(101,902)
Regulatory assets	(2,205)	31,081
Regulatory liabilities	7,176	23,191
Contributions to defined pension plans	(30,015)	(16,945)
Other operating activities	7,765	1,588
Net cash provided by operating activities of continuing operations	125,761	268,371
Net cash provided by operating activities of discontinued operations	—	2,556
Net cash provided by operating activities	125,761	270,927
Investing activities:		
Property, plant and equipment additions	(323,883)	(245,114)
Proceeds from sale of ownership interest in operating assets	68,105	84,661
Payment for acquisition of business	(2,250)	—
Working capital adjustment of purchase price allocation on Aquila assets	—	7,098
Other investing activities	4,273	1,933
Net cash used in investing activities	(253,755)	(151,422)
Financing activities:		
Dividends paid	(42,331)	(41,338)
Common stock issued	3,073	2,338
Short-term borrowings - issuances	451,500	484,500
Short-term borrowings - repayments	(471,000)	(837,800)

Long-term debt - issuances	200,000	248,500
Long-term debt - repayments	(57,550)	(2,024)
Other financing activities	(9,624)	(4,532)
Net cash provided by (used in) financing activities	74,068	(150,356)
Decrease in cash and cash equivalents	(53,926)	(30,851)
Cash and cash equivalents:		
Beginning of period	112,901	168,532
End of period	$58,975	$137,681

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

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2009 Annual Report on Form 10-K)

(1) MANAGEMENT'S STATEMENT

The condensed consolidated financial statements included herein have been prepared by Black Hills Corporation (the "Company," "us," "we," or "our") without audit, pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations; however, we believe that the footnotes adequately disclose the information presented. These condensed quarterly financial statements should be read in conjunction with the financial statements and the notes thereto, included in our 2009 Annual Report on Form 10-K filed with the SEC.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying condensed quarterly financial statements reflects all estimates which are, in the opinion of management, necessary for a fair presentation of the September 30, 2010, December 31, 2009 and September 30, 2009 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal and revenues from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market price. In particular, the normal peak usage season for gas utilities is November through March and significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2010 and September 30, 2009, and our financial condition as of September 30, 2010 and December 31, 2009, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

Certain prior year data presented in the financial statements have been reclassified to conform to the current year presentation. These reclassifications had no effect on total assets, net income, cash flows or earnings per share.

(2) RECENTLY ADOPTED AND RECENTLY ISSUED ACCOUNTING STANDARDS AND LEGISLATION

Recently Adopted Accounting Standards

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

The FASB issued an accounting standards update which aligns the oil and gas reserve estimation and disclosure requirements with the SEC released Final Rule, "Modernization of Oil and Gas Reporting" amending the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technology advances. Key revisions include the ability to include non-traditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the 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.

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

In June 2009, the FASB issued a revision regarding consolidations. The amendment requires a company to consider whether an entity that is insufficiently capitalized or is not controlled through voting should be consolidated. It requires additional disclosures about the involvement with variable interest entities and any significant changes in risk exposure due to that involvement. This standard is effective for annual periods that begin after November 15, 2009 with ongoing re-evaluation. The adoption of this standard in January 2010 did not have any impact on our consolidated financial statements, results of operations, and cash flows.

Fair Value Measurements, ASC 820

In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements, 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 on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective on January 1, 2011. The guidance requires additional disclosures, but did not impact our financial position, results of operations or cash flows. The additional disclosures are included in Note 14 of the accompanying Notes to Condensed Consolidated Financial Statements.

Recently Issued Accounting Standards and Legislation

Patient Protection and Affordable Care Act

In March 2010, the President of the United States signed into law comprehensive healthcare reform legislation under the PPACA as amended by the Healthcare and Education Reconciliation Act. The potential impact on the Company, if any, cannot be determined until regulations are promulgated under the PPACA. Included among the provisions of the PPACA is a change in the tax treatment of the Medicare Part D subsidy (the "subsidy") which affects our Non-Pension Postretirement Benefit Plan. Internal Revenue Code Section 139A has been amended to eliminate the deduction of the subsidy in reducing income for years beginning after December 31, 2012. The impact of this change in the tax treatment of the subsidy had an immaterial effect on our financial position, results of operations and cash flows. The Company will continue to assess the accounting implications of the PPACA as related regulations and interpretations become available.

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. Significant rule-making by numerous governmental agencies, particularly the CFTC with respect to non-security commodities, will be required over the next several months to implement the restrictions, limitations, and requirements contemplated by Dodd-Frank, and we will continue to evaluate the impact as these rules become available.

Disclosures About the Credit Quality of Financing Receivables and the Allowance for Credit Losses (ASC 310-10-50)

In July 2010, the FASB issued an amendment to ASC 310-10-50, Receivables - Disclosures. The guidance requires additional disclosures that will facilitate financial statement user's evaluation of the nature of credit risk inherent in financing receivables, how that risk is analyzed in arriving at the allowance for credit losses, and the reason for any changes in the allowance for credit losses. These disclosures should be provided on a disaggregated basis but exempts trade receivables that have a contractual maturity of one year or less, receivables measured at lower of cost or fair value, and receivables measured at fair value with the changes in fair value reported in earnings. We are currently evaluating the disclosure requirements of this amendment. It is effective for interim and annual reporting periods ending on or after December 15, 2010.

(3) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Nine Months Ended September 30, 2010 (in thousands)	September 30, 2009
Non-cash investing activities—		
Property, plant and equipment acquired with accrued liabilities	$37,661	$31,202
Cash (paid) refunded during the period for—		
Interest (net of amounts capitalized)	$(62,740)	$(50,311)
Income taxes	$(488)	$23,311

(4) MATERIALS, SUPPLIES AND FUEL

The amounts of materials, supplies and fuel included on the accompanying Condensed Consolidated Balance Sheets, by major classification, were as follows (in thousands):

Major Classification	September 30, 2010	December 31, 2009	September 30, 2009
Materials and supplies	$31,192	$31,535	$31,650
Fuel - Electric Utilities	9,056	7,128	7,234
Natural gas in storage — Gas Utilities	36,782	24,053	29,943
Gas and oil held by Energy Marketing*	68,221	60,606	31,125
Total materials, supplies and fuel	$145,251	$123,322	$99,952

* As of September 30, 2010, December 31, 2009 and September 30, 2009, market adjustments related to natural gas held by Energy Marketing and recorded in inventory were $(18.7) million, $(0.3) million and $(1.3) million, respectively (see Note 13 for further discussion of Energy Marketing trading activities).

(5) ACCOUNTS RECEIVABLE AND ALLOWANCE FOR DOUBTFUL ACCOUNTS

Our Accounts receivable represents primarily customer trade accounts at our Electric Utilities and Gas Utilities and counterparty trade accounts at our Energy Marketing segment. This balance fluctuates primarily due to the seasonality of our regulated Gas Utilities and volumes and commodity prices at our Energy Marketing segment. In addition at September 30, 2010, our trade receivables include $25 million on deposit with a counterparty related to interest rate swaps. During October 2010, this cash collateral posting was replaced with a letter of credit. We maintain an allowance for doubtful accounts which reflects our best estimate of potentially uncollectible trade accounts. We regularly review our trade receivables allowance by considering such factors as historical experience, credit-worthiness, the age of the account balances and current economic conditions that may affect our ability to collect.

Following is a summary of receivables (in thousands):

	September 30, 2010	December 31, 2009	September 30, 2009
Accounts receivable, trade	$207,707	$217,723	$186,123
Unbilled revenues	29,066	61,387	27,942
Total accounts receivable	236,773	279,110	214,065
Less allowance for doubtful accounts	(2,293)	(4,621)	(5,502)
Accounts receivable, net	$234,480	$274,489	$208,563

(6) NOTES PAYABLE

Our credit facilities and debt securities contain certain restrictive covenants including, among others, recourse leverage ratios and consolidated net worth covenants. As of September 30, 2010, we were in compliance with these covenants. None of our facilities or debt securities contain default provisions pertaining to our credit ratings.

Revolving Credit Facility

On April 15, 2010, we terminated our $525 million Corporate Credit Facility and entered into a new $500 million Revolving Credit Facility expiring April 14, 2013. The new facility contains an accordion feature which allows us to increase the capacity of the new facility to $600 million and can be used for the issuance of letters of credit, to fund working capital needs and other corporate purposes. The covenants and events of default are substantially the same as the prior facility, except the minimum interest expense coverage ratio covenant was eliminated. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 1.75%, 2.75% and 2.75%, respectively at September 30, 2010. The new facility contains a commitment fee to be charged on the unused amount of the Facility. Based upon current credit ratings, the fee is 0.5%.

Deferred financing costs of $4.7 million are being amortized over the three-year term of the facility and included in Interest expense on the accompanying Condensed Consolidated Income Statement are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Amortization Expense	$481	$148	$866	$445

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 September 30, 2010.

	Actual	Covenant Requirement
Consolidated Net Worth	$1,080,407	$842,506
Recourse leverage ratio	56.1 %	65.0 %

Enserco Credit Facility

In May 2010, Enserco entered into an agreement for a two-year $250 million committed credit facility. The facility contains an accordion feature which allows us, with the consent of the administrative agent, to increase commitments under the facility to $350 million. This facility replaces the $300 million credit facility which expired on May 7, 2010. Maximum borrowings under the facility are subject to a sub-limit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. Margins for base rate borrowings are 1.75% and for Eurodollar borrowings are 2.50%.

At September 30, 2010, $131.5 million of letters of credit were issued and outstanding under this facility and there were no cash borrowings outstanding.

Deferred financing costs of $2.1 million were recorded for the Enserco Credit Facility and are being amortized over the term of the Enserco Credit Facility. Amortization of deferred financing costs included in Interest expense on the accompanying Condensed Consolidated Statement of Income was as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Amortization expense	$263	$540	$1,245	$982

The June 1, 2010 coal marketing acquisition (see Note 20) included certain contractual positions that caused Enserco to temporarily not be in compliance with one of the non-financial covenants to the Enserco Credit Facility as of June 30, 2010. The Enserco Credit Facility limited the net fixed price volume of coal to 1.0 million tons. As of June 30, 2010, Enserco was above that limit. In July, the participating banks waived the non-compliance with this covenant and increased the permitted net fixed price volume of coal allowed to 2.25 million tons for July 2010 and 2.0 million tons thereafter. Enserco was in compliance with this covenant as of September 30, 2010.

In September 2010, the Enserco Credit Facility was amended to allow for trading of electric power, renewable energy credits and emissions credits.

(7) LONG-TERM DEBT

Black Hills Power Series AC Bonds

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

Black Hills Power Series Y Bonds

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 Condensed Consolidated Balance Sheets and is being amortized over the remaining term of the original bonds.

Black Hills Power Series Z 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 Condensed Consolidated Balance Sheets and is being amortized over the remaining term of the original bonds.

$200 Million Debt Offering

On July 16, 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 5.875%. We received proceeds of $198.7 million, net of underwriting fees. Deferred financing costs of $1.7 million are being amortized over the 10-year term of the debt. Proceeds were used to pay down a portion of borrowings on our Revolving Credit Facility and to reduce issued letters of credit.

(8) EARNINGS PER SHARE

Basic earnings per share from continuing operations are computed by dividing income from continuing operations by the weighted-average number of common shares outstanding during the period. Diluted earnings per share from continuing operations are computed by using all dilutive common shares potentially outstanding during a period. A reconciliation of Income from continuing operations and basic and diluted share amounts, used to compute earnings per share, is as follows (in thousands, except per share amounts):

Period ended September 30, 2010	Three Months Income	Average Shares	Nine Months Income	Average Shares
Income from continuing operations	$12,390		$35,165	
Basic earnings	$12,390	38,933	$35,165	38,895
Dilutive effect of:				
Restricted stock	—	131	—	110
Options	—	12	—	9
Other	—	57	—	39
Diluted earnings	$12,390	39,133	$35,165	39,052
Diluted earnings per share from continuing operations	$0.32		$0.90	

Period ended September 30, 2009	Three Months Income	Average Shares	Nine Months Income	Average Shares
(Loss) income from continuing operations	$(3,853)		$46,353	
Basic earnings	$(3,853)	38,643	$46,353	38,584
Dilutive effect of:				
Restricted stock	—	—	—	60
Other	—	—	—	2
Diluted (loss) earnings	$(3,853)	38,643	$46,353	38,646
Diluted (loss) earnings per share from continuing operations	$(0.10)		$1.20	

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):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Options to purchase common stock	128	374	169	484
Restricted stock	2	1	2	11
Other	1	53	1	56
	131	428	172	551

(9) OTHER COMPREHENSIVE INCOME (LOSS)

The following table presents the components of our other comprehensive income (loss) (in thousands):

	Three Months Ended September 30, 2010	
Net income		$12,390
Other comprehensive income (loss), net of tax:		
Minimum pension liability adjustments	—	
Taxes	—	
Minimum pension liability adjustments, net of tax		—
Fair value adjustment on derivatives designated as cash flow hedges	517	
Taxes	486	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		1,003
Reclassification adjustments on cash flow hedges settled and included in net income (loss)	(4,730)	
Taxes	1,761	
Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax		(2,969)
Comprehensive income		$10,424

	Three Months Ended September 30, 2009	
Net loss		$(2,180)
Other comprehensive (loss) income, net of tax:		
Minimum pension liability adjustments	5,670	
Taxes	(1,999)	
Minimum pension liability adjustments, net of tax		3,671
Fair value adjustment on derivatives designated as cash flow hedges	(15,981)	
Taxes	5,670	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		(10,311)
Reclassification adjustments on cash flow hedges settled and included in net income (loss)	5,394	
Taxes	(1,948)	
Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax		3,446
Comprehensive loss		$(5,374)

	Nine Months Ended September 30, 2010	
Net income		$35,165
Other comprehensive income, net of tax:		
Minimum pension liability adjustments	(8)	
Taxes	(7)	
Minimum pension liability adjustments, net of tax		(15)
Fair value adjustment on derivatives designated as cash flow hedges	495	
Taxes	641	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		1,136
Reclassification adjustments on cash flow hedges settled and included in net income	(6,909)	
Taxes	2,543	
Reclassification adjustments on cash flow hedges settled and included in net income, net of tax		(4,366)
Comprehensive income		$31,920

	Nine Months Ended September 30, 2009	
Net income		$48,792
Other comprehensive income, net of tax:		
Minimum pension liability adjustments	5,670	
Taxes	(1,999)	
Minimum pension liability adjustments, net of tax		3,671
Fair value adjustment on derivatives designated as cash flow hedges	(23,704)	
Taxes	8,598	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		(15,106)
Reclassification adjustments on cash flow hedges settled and included in net income	16,617	
Taxes	(6,008)	
Reclassification adjustments on cash flow hedges settled and included in net income, net of tax		10,609
Comprehensive income		$47,966

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

	September 30, 2010	December 31, 2009	September 30, 2009
Derivatives designated as cash flow hedges	$(12,741)	$(9,462)	$(9,037)
Employee benefit plans	(9,636)	(9,636)	(10,456)
Amount from equity-method investees	(32)	(66)	(116)
Total	$(22,409)	$(19,164)	$(19,609)

(10) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock during the first nine months of 2010 as reported in Note 11 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K.

Equity Compensation Plans

- We granted 77,693 target performance shares to certain officers and business unit leaders for the January 1, 2010 through December 31, 2012 performance period. Actual shares are not issued until the end of the performance plan period (December 31, 2012). Performance shares are awarded based on our total stockholder return over the designated performance period as measured against a selected peer group and can range from 0% to 175% of target. In addition, the ending stock price must be at least equal to 75% of the beginning stock price 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 the form of cash and 50% in shares of common stock. The grant date fair value was $24.25 per share.

- We issued 9,625 shares of common stock under the 2009 short-term incentive compensation plan during the nine months ended September 30, 2010. Pre-tax compensation cost related to the awards was approximately $0.3 million, which was accrued for in 2009.

- We granted 172,674 restricted common shares during the nine months ended September 30, 2010. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $4.7 million will be recognized over the three-year vesting period.

- 30,000 stock options were exercised during the nine months ended September 30, 2010 at a weighted-average exercise price of $21.875 per share which provided $0.7 million of proceeds.

Total compensation expense recognized for all equity compensation plans for the three months ended September 30, 2010 and 2009 was $1.9 million and $1.1 million, respectively, and for the nine months ended September 30, 2010 and 2009 was $4.7 million and $2.9 million, respectively.

As of September 30, 2010, total unrecognized compensation expense related to non-vested stock awards was $8.2 million and is expected to be recognized over a weighted-average period of 2.0 years.

Dividend Reinvestment and Stock Purchase Plan

We have a Dividend Reinvestment and Stock Purchase Plan under which stockholders 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 issued 82,875 new shares at a weighted-average price of $29.17 during the nine months ended September 30, 2010. At September 30, 2010, 213,107 shares of unissued common stock were available for future offering under the Plan.

Dividend Restrictions

Our Revolving Credit Facility contains restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenants include the following: 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, if positive, since January 1, 2005. As of September 30, 2010, we were in compliance with the above covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed as of September 30, 2010:

- 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 September 30, 2010, the restricted net assets at our Utilities Group were approximately $245.0 million.
- Our 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 September 30, 2010 were $104.6 million.
- Pursuant to a covenant in the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted assets of $100.0 million. Black Hills Non-regulated Holdings is the parent of Black Hills Electric Generation which is the parent of Black Hills Wyoming.

(11) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

We have three non-contributory defined benefit pension plans (the "Plans"). One Plan covers employees of the following subsidiaries who meet certain eligibility requirements: Black Hills Service Company, Black Hills Power, WRDC and BHEP. The second Plan covers employees of our subsidiary, Cheyenne Light, who meet certain eligibility requirements. The third Plan covers employees of the Black Hills Energy utilities who meet certain eligibility requirements.

The components of net periodic benefit cost for the three Plans are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Service cost	$1,533	$1,877	$4,599	$5,736
Interest cost	3,773	3,679	11,319	11,036
Expected return on plan assets	(3,623)	(3,638)	(10,869)	(10,553)
Prior service cost	305	25	915	108
Net loss	500	637	1,500	2,140
Curtailment expense	—	320	—	320

Net periodic benefit cost	$2,488	$2,900	$7,464	$8,787

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In September 2010, bargaining unit participants in the Black Hills Corporation Pension Plan (the "Plan") voted to ratify a partial freeze to the Plan which is effective January 1, 2011. The partial freeze eliminates new bargaining unit employees from participation in the Plan, and freezes the benefits of current participants except for the following group: those participants who both 1) are age 45 or older as of December 31, 2010 and have 10 years or more of credited service as of January 1, 2011; and 2) elect to continue to accrue additional benefits under the pension plan and consequently forgo the additional age- and service points-based employer contribution under the Company's 401(k) retirement savings plan. The assets and obligations for the Black Hills Corporation Pension Plan will be revalued at December 31, 2010 during the year-end valuation process and any pre-tax curtailment effect related to this partial freeze will be recorded by the Company in the fourth quarter of 2010. The adjustment is expected to be less than $0.1 million.

Non-pension Defined Benefit Postretirement Healthcare Plans

We sponsor three retiree healthcare plans (the "Healthcare Plans"): the Black Hills Corporation Postretirement Healthcare Plan, the Healthcare Plan for Retirees of Cheyenne Light, and the Black Hills Energy Postretirement Healthcare Plan. Employees who participate in the Healthcare Plans and who retire on or after meeting certain eligibility requirements are entitled to postretirement healthcare benefits.

The components of net periodic benefit cost for the Healthcare Plans are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Service cost	$377	$260	$1,131	$780
Interest cost	611	542	1,833	1,626
Expected return on plan assets	(52)	(56)	(156)	(168)
Prior service benefit	(77)	(22)	(231)	(66)
Net transition obligation	—	15	—	45
Net loss (gain)	159	(8)	477	(24)
Net periodic benefit cost	$1,018	$731	$3,054	$2,193

It has been determined that our post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy. The decrease in net periodic postretirement benefit cost due to the subsidy was approximately $0.2 million and $0.1 million for the three and nine months ended September 30, 2010, respectively, and $0.1 million and $0.3 million for the three and nine months ended September 30, 2009, respectively.

Supplemental Non-qualified Defined Benefit Plans

Additionally, we have various supplemental retirement plans for key executives (the "Supplemental Plans"). The Supplemental Plans are non-qualified defined benefit plans.

The components of net periodic benefit cost for the Supplemental Plans are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Service cost	$171	$117	$513	$351
Interest cost	321	344	963	1,032
Prior service cost	1	1	3	3

Net loss	71	147	213	441
Net periodic benefit cost	$564	$609	$1,692	$1,827

Contributions

We anticipate that we will make contributions to each of the benefit plans during 2010 and 2011. Contributions to the Healthcare Plans and the Supplemental Plans are expected to be made in the form of benefit payments. Contributions are as follows (in thousands):

	Contributions Made Three Months Ended September 30, 2010	Contributions Made Nine Months Ended September 30, 2010	Contributions Remaining for 2010	Contributions Anticipated for 2011
Defined Benefit Pension Plans	$30,000	$30,015	$—	$5,100
Non-Pension Defined Benefit Postretirement Healthcare Plans	$950	$2,850	$950	$4,000
Supplemental Non-Qualified Defined Benefit Plans	$223	$669	$223	$900

(12) SUMMARY OF INFORMATION RELATING TO SEGMENTS OF OUR BUSINESS

Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of September 30, 2010, substantially all of our operations and assets were located within the United States.

We conduct our operations through the following six reportable segments:

Utilities Group —

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

- Gas Utilities, which supplies natural gas utility service in Colorado, Iowa, Kansas and Nebraska.

Non-regulated Energy Group —

- Oil and Gas, which produces, explores and operates oil and natural gas interests located in the Rocky Mountain region and other states;

- Power Generation, which produces and sells power and capacity to wholesale customers from power plants located in Wyoming and Idaho. Additionally, in 2009 our Power Generation segment entered into a 20-year PPA to supply Colorado Electric with 200 MW of capacity and energy from power plants under construction in Colorado, which are expected to be placed into service by December 31, 2011;

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

- Energy Marketing, which markets natural gas, crude oil and coal and related services in the United States and Canada. Additionally, during the third quarter of 2010, Enserco expanded business lines to include power and environmental marketing.

Segment information follows the accounting policies described in Note 1 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K. In accordance with accounting standards for regulated operations, intercompany fuel and energy sales to the regulated utilities are not eliminated.

Segment information included in the accompanying Condensed Consolidated Statements of Income and Balance Sheets was as follows (in thousands):

Three Months Ended September 30, 2010	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric [(a)]	$142,587	$(942)	$18,537
Gas	72,323	—	(595)
Non-regulated Energy:			
Oil and Gas	19,354	—	836
Power Generation	7,855	—	575
Coal Mining	7,744	6,533	1,673
Energy Marketing	8,973	—	1,370
Corporate [(b)]	—	—	(10,093)
Inter-segment eliminations	—	(72)	87
Total	$258,836	$5,519	$12,390

Three Months Ended September 30, 2009	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$128,943	$223	$10,537
Gas	62,691	—	(3,484)
Non-regulated Energy:			
Oil and Gas	17,887	—	(149)
Power Generation	7,538	—	575
Coal Mining	8,284	6,903	2,256
Energy Marketing	(5,259)	—	(4,404)
Corporate [(b)]	—	—	(9,110)
Inter-segment eliminations	—	(1,411)	(74)
Total	$220,084	$5,715	$(3,853)

Nine Months Ended September 30, 2010	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$426,719	$—	$35,585
Gas [(c)]	402,608	—	18,017
Non-regulated Energy:			
Oil and Gas	57,755	—	3,405
Power Generation	22,602	—	1,239
Coal Mining	22,431	20,875	6,093
Energy Marketing	27,640	—	4,890
Corporate [(b)]	—	—	(34,221)
Inter-segment eliminations	—	(2,652)	157
Total	$959,755	$18,223	$35,165

Nine Months Ended September 30, 2009	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$384,607	$653	$24,395
Gas	412,366	—	14,223
Non-regulated Energy:			
Oil and Gas [d]	52,227	—	(25,740)
Power Generation [e]	22,372	—	18,487
Coal Mining	23,967	19,115	2,575
Energy Marketing	9,299	—	(1,156)
Corporate [b]	—	—	13,205
Inter-segment eliminations	—	(3,516)	364
Total	$904,838	$16,252	$46,353

(a) Income (loss) from continuing operations includes a $4.1 million after-tax gain on the sale to the City of Gillette of 23% ownership interest in Wygen III power generation facility. (See Note 19)
(b) Income (loss) from continuing operations includes a $8.9 million and a $27.1 million net after-tax mark-to-market loss on interest rate swaps for the three and nine months ended September 30, 2010 and a $5.7 million net after-tax mark-to-market loss and a $24.6 million net after-tax gain on interest rate swaps for the three and nine months ended September 30, 2009, respectively.
(c) Income (loss) from continuing operations includes a $1.7 million after-tax gain on sale of operating assets at Nebraska Gas. (See Note 19)
(d) As a result of lower natural gas prices at March 31, 2009, our Income (loss) from continuing operations reflects a ceiling test impairment of oil and gas assets of $27.8 million after-tax included in the first quarter of 2009. (See Note 18)
(e) Income (loss) from continuing operations includes a $16.9 million after-tax gain on the sale to MEAN of 23.5% ownership interest in Wygen I power generation facility.

Total assets	September 30, 2010	December 31, 2009	September 30, 2009
Utilities:			
Electric	$1,771,014	$1,659,375	$1,592,852
Gas	659,801	684,375	619,855
Non-regulated Energy:			
Oil and Gas	358,113	338,470	340,046
Power Generation	249,778	161,856	120,426
Coal Mining	94,149	76,209	79,796
Energy Marketing	287,173	321,207	341,720
Corporate	120,209	76,206	73,640
Total	$3,540,237	$3,317,698	$3,168,335

(13) RISK MANAGEMENT ACTIVITIES

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

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

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

- Interest rate risk associated with variable rate credit facilities and changes in forward interest rates used to determine the mark-to-market adjustment on our interest rate swaps; and

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

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

We actively manage our exposure to certain market risks as described in Note 3 of the Notes to our Consolidated Financial Statements in our 2009 Annual Report on Form 10-K. Our derivative and hedging activities included in the accompanying Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Income are detailed in this Note along with Note 14.

Trading Activities

Natural Gas, Crude Oil and Coal Marketing

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

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

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

We use a number of quantitative tools to measure, monitor and limit our exposure to market risk in our natural gas, crude oil and coal 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.

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

The contract or notional amounts and terms of our natural gas, crude oil and coal marketing activities and derivative commodity instruments were as follows:

	Outstanding at September 30, 2010		Outstanding at December 31, 2009		Outstanding at September 30, 2009	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of MMBtus)						
Natural gas basis swaps purchased	335,805	25	231,703	22	246,175	25
Natural gas basis swaps sold	358,929	25	232,673	22	242,246	25
Natural gas fixed-for-float swaps purchased	84,636	36	60,927	16	89,371	18
Natural gas fixed-for-float swaps sold	97,210	18	72,904	25	94,619	18
Natural gas physical purchases	135,818	18	120,680	27	150,698	18
Natural gas physical sales	136,530	36	124,830	27	179,134	18
Natural gas options purchased	—	—	—	—	1,227	6
Natural gas options sold	—	—	—	—	1,227	6

	Outstanding at September 30, 2010		Outstanding at December 31, 2009		Outstanding at September 30, 2009	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of Bbls)						
Crude oil physical purchases	5,561	15	5,048	12	3,263	4
Crude oil physical sales	4,759	15	4,998	12	3,126	4
Crude oil swaps/options purchased	135	1	—	—	—	—
Crude oil swaps/options sold	289	3	69	2	64	3

	Outstanding at September 30, 2010 *	
	Notional Amounts	Latest Expiration (months)
(in thousands of tons)		
Coal fixed-for-float swaps purchased	5,585	39
Coal fixed-for-float swaps sold	4,445	39
Coal physical purchases	24,100	51
Coal physical sales	6,213	35

Coal options purchased	1,980	27
Coal options sold	360	15

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* Coal contracts represent the contractual positions of the coal marketing business acquired on June 1, 2010 and contracts arising from subsequent trading activity.

Derivatives and certain natural gas, crude oil and coal marketing activities were marked to fair value on September 30, 2010, December 31, 2009 and September 30, 2009, and the related gains and/or losses recognized in earnings. The amounts included in the accompanying Condensed Consolidated Balance Sheets and Statements of Income were as follows (in thousands):

	September 30, 2010	December 31, 2009	September 30, 2009
Derivative assets, current	$55,366	$25,366	$38,650
Derivative assets, non-current	$8,023	$3,090	$4,547
Derivative liabilities, current	$17,743	$9,377	$14,668
Derivative liabilities, non-current	$1,277	$(733)	$646
Cash collateral (receivable)/payable included in derivative assets/liabilities	$7,365	$(2,728)	$(4,829)
Unrealized gain	$51,734	$17,084	$23,054

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in fair value hedge transactions. These volumes include market adjustments based on published industry quotations. Market adjustments are recorded in Materials, supplies and fuel on the accompanying Condensed Consolidated Balance Sheets and the related unrealized gain/loss on the Condensed Consolidated Statements of Income, effectively offsetting the earnings impact of the unrealized gain/loss recognized on the associated derivative asset or liability described above. As of September 30, 2010, December 31, 2009 and September 30, 2009, the market adjustments recorded in inventory were $(18.7) million, $(0.3) million and $(1.3) million, respectively.

Activities Other Than Trading

Oil and Gas Exploration and Production

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

As of September 30, 2010, December 31, 2009 and September 30, 2009, we had a portfolio of swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on those over-the-counter swaps and options. These transactions were designated at inception as cash flow hedges, 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 are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives is reported in other comprehensive income and the ineffective portion is reported in earnings.

We had the following derivatives and related balances (dollars in thousands):

	September 30, 2010		December 31, 2009		September 30, 2009	
	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps
Notional*	484,500	8,109,800	472,500	9,602,300	450,000	9,448,050
Maximum terms in years **	0.25	0.25	0.25	0.75	0.25	0.75
Derivative assets, current	$466	$8,816	$3,345	$5,994	$5,091	$8,607
Derivative assets, non-current	$216	$4,523	$136	$551	$128	$241
Derivative liabilities, current	$3,224	$—	$1,220	$1,435	$—	$1,079
Derivative liabilities, non-current	$497	$—	$2,502	$391	$1,895	$1,934
Pre-tax accumulated other comprehensive income (loss) included in balance sheets	$(3,611)	$13,339	$(862)	$4,719	$2,840	$5,835
Earnings	$572	$—	$621	$—	$484	$—

* Crude in Bbls, gas in MMBtu.

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

Based on September 30, 2010 market prices, a $5.3 million gain would be realized and reported in pre-tax earnings during the next 12 months related to hedges of production. Estimated and actual realized gains will likely change during the next 12 months as market prices change.

Regulated Gas Utilities - Gas Hedges

Our Gas Utilities segment purchases and distributes natural gas in four states. During the winter heating season, our gas 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 mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. Gains and losses, as well as option premiums upon settlement, 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 Income Statements 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 our natural gas derivative commodity instruments were as follows:

	Outstanding at September 30, 2010		Outstanding at December 31, 2009		Outstanding at September 30, 2009	
	Notional Amounts (MMBtus)	Latest Expiration (months)	Notional Amounts (MMBtus)	Latest Expiration (months)	Notional Amounts (MMBtus)	Latest Expiration (months)
Natural gas futures purchased	11,800,000	18	6,220,000	15	9,790,000	18
Natural gas options purchased	3,980,000	6	1,910,000	3	3,870,000	6
Natural gas basis swaps purchased	—	—	225,000	3	378,000	6

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We had the following derivative balances related to the hedges in our regulated gas utilities (in thousands):

	September 30, 2010	December 31, 2009	September 30, 2009
Derivative assets, current	$6,685	$3,042	$4,603
Derivative assets, non-current	$—	$—	$522
Derivative liabilities, non-current	$2,600	$764	$75
Net unrealized gain (loss) included in regulatory assets	$18,381	$2,578	$(1,105)
Cash collateral (receivable) payable included in derivative assets/liabilities	$(20,519)	$(3,789)	$(1,840)
Option premium included in Derivative assets, current	$1,947	$1,067	$2,105

Fuel in Storage

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

We had the following swaps and related balances (dollars in thousands):

	September 30, 2010	December 31, 2009	September 30, 2009
Notional - Forward purchase *	232,500	232,500	232,500
Notional - Forward sale *	232,500	—	—
Maximum terms in months	1	10	12
Current derivative asset	$355	$—	—
Current derivative liability	$—	$5	42
Pre-tax accumulated other comprehensive income (loss) included in the Condensed Consolidated Balance Sheets	$355	$(5)	(42)

* Gas in MMBtus

Financing Activities

We are exposed to interest rate risk associated with fluctuations in the interest rate on our variable interest rate debt. In order to manage this risk, we have entered into floating-to-fixed interest rate swap agreements with the intention to convert the debt's variable interest rate to a fixed rate.

Our interest rate swaps and related balances were as follows (dollars in thousands):

	September 30, 2010		December 31, 2009		September 30, 2009	
	Designated Interest Rate Swaps	Dedesignated Interest Rate Swaps*	Designated Interest Rate Swaps	Dedesignated Interest Rate Swaps*	Designated Interest Rate Swaps	Dedesignated Interest Rate Swaps*
Current notional amount	$150,000	$250,000	$150,000	$250,000	$150,000	$250,000
Weighted average fixed interest rate	5.04 %	5.67 %	5.04 %	5.67 %	5.04 %	5.67 %
Maximum terms in years	6.25	0.25	7.00	1.00	7.25	1.25
Derivative liabilities, current	$6,901	$80,450	$6,342	$38,787	$6,513	$46,332
Derivative liabilities, non-current	$21,518	$—	$9,075	$—	$12,941	$10,333
Pre-tax accumulated other comprehensive loss included in Condensed Consolidated Balance Sheets	$(28,419)	$—	$(15,417)	$—	$(19,454)	$—
Pre-tax (loss) gain included in Condensed Consolidated Income Statements	$—	$(41,663)	$—	$55,653	$—	$37,775
Cash collateral (receivable) payable included in accounts receivable	—	(25,000)	—	—	—	—

* Maximum terms in years reflect the amended mandatory early termination dates of the eight and eighteen year de-designated swaps. If the mandatory early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date.

Based on September 30, 2010 market interest rates and balances related to our $150 million in designated interest rate swaps, a loss of approximately $6.9 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change. Note 14 provides further information related to the $250 million notional swaps that are not designated as hedges for accounting purposes.

Foreign Exchange Contracts

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

We had the following outstanding forward contracts included in Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets as follows (in thousands):

	As of September 30, 2010		As of December 31, 2009		As of September 30, 2009	
	Outstanding Notional Amounts	Latest Expiration (Months)	Outstanding Notional Amounts	Latest Expiration (Months)	Outstanding Notional Amounts	Latest Expiration (Months)
Canadian dollars purchased	$5,000	1	$—	—	$2,500	1
Canadian dollars sold	$—	—	$—	—	$13,000	3

Our outstanding foreign exchange contracts had a fair value as follows (in thousands):

	As of September 30, 2010	As of December 31, 2009	As of September 30, 2009
Fair Value	$(11)	$—	$40

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We recognized the following gains and losses in Operating revenues on the accompanying Condensed Consolidated Statements of Income (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Unrealized foreign exchange gain (loss)	$97	$304	$181	$281
Realized foreign exchange gain (loss)	$(61)	$946	$(652)	$1,651

(14) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

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 or 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 its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Recurring Fair Value Measures

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 as of September 30, 2010, December 31, 2009 and September 30, 2009 (in thousands):

	As of September 30, 2010				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[(a)]	Total
Assets:					
Commodity derivatives — Energy Marketing	$—	$221,740	$3,246	$(161,693)	$63,293
Commodity derivatives — Oil and Gas	—	13,459	562	—	14,021
Commodity derivatives — Regulated Utilities Group	—	(13,382)	—	20,518	7,136
Money market funds	10,050	—	—	—	10,050
Total	$10,050	$221,817	$3,808	$(141,175)	$94,500
Liabilities:					
Commodity derivatives — Energy Marketing	$—	$172,401	$840	$(154,327)	$18,914
Commodity derivatives — Oil and Gas	—	3,720	—	—	3,720
Commodity derivatives — Regulated Utilities Group	—	2,696	—	—	2,696
Foreign currency derivative	—	11	—	—	11
Interest rate swaps	—	108,869	—	—	108,869
Total	$—	$287,697	$840	$(154,327)	$134,210

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

	As of September 30, 2009				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[a]	Total
Assets:					
Commodity derivatives	$—	$213,296	$11,519	$(162,537)	$62,278
Money market funds	6,005	—	—	—	6,005
Foreign currency derivatives	—	111	—	—	111
	$6,005	$213,407	$11,519	$(162,537)	$68,394
Liabilities:					
Commodity derivatives	$—	$183,566	$5,908	$(169,206)	$20,268
Foreign currency derivatives	—	71	—	—	71
Interest rate swaps	—	76,119	—	—	76,119
Total	$—	$259,756	$5,908	$(169,206)	$96,458

(a) Cash Collateral on deposit in margin accounts under master netting agreements at September 30, 2010, December 31, 2009 and September 30, 2009 totaled a net $13.2 million, $6.5 million and $6.7 million, respectively.

The following tables present the changes in level 3 recurring fair value for the three and nine months ended September 30, 2010 and 2009, respectively (in thousands):

	Three Months Ended September 30, 2010 Commodity Derivatives	Nine Months Ended September 30, 2010 Commodity Derivatives
Balance as of beginning of period	$2,176	$(556)
Unrealized losses	961	(1,206)
Unrealized gains	850	4,576
Purchases, issuance and settlements	(365)	(1,170)
Transfers into level 3 [a]	(62)	(78)
Transfers out of level 3[b]	(592)	1,402
Balances at end of period	$2,968	$2,968
Changes in unrealized gains relating to instruments still held as of quarter-end	$(528)	$1,283

	Three Months Ended September 30, 2009 Commodity Derivatives	Nine Months Ended September 30, 2009 Commodity Derivatives
Balance as of beginning of period	$5,153	$16,398
Realized and unrealized losses	(2,628)	(4,183)
Purchases, issuance and settlements	2,590	(3,464)
Transfers in and/or out of level 3 [(a)] [(b)]	496	(3,140)
Balances at end of period	$5,611	$5,611
Changes in unrealized losses relating to instruments still held as of quarter-end	$3,556	$(6,899)

(a) Transfers into level 3 represent assets and liabilities that were previously categorized as a higher level for which the inputs became unobservable.

(b) Transfers out of level 3 represent 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 $1.6 million and $2.9 million for the three and nine months ended September 30, 2010, respectively, are included in Operating revenues on the accompanying Condensed Consolidated Statements of Income while $0.2 million and $0.5 million was recorded through Accumulated other comprehensive income on the accompanying Condensed Consolidated Balance Sheet for the three and nine months ended September 30, 2010, respectively. 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 quarter.

Fair Value Measures

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis and do not reflect the netting of asset and liability positions. Further, the amounts do not include net cash collateral of $(13.2) million, $(6.5) million and $(6.7) million on deposit in margin accounts at September 30, 2010, December 31, 2009, and September 30, 2009, respectively, to collateralize certain financial instruments, which is included in Derivative assets - current, Derivative assets - non-current and Derivative liabilities - current. Therefore, the gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Condensed Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 13.

The following tables present the fair value and balance sheet classification of our derivative instruments as of September 30, 2010 and 2009 (in thousands):

As of September 30, 2010

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$20,387	$1,329
Commodity derivatives	Derivative assets — non-current	11	—
Commodity derivatives	Derivative liabilities — current	—	219
Commodity derivatives	Derivative liabilities — non-current	—	3
Interest rate swaps	Derivative liabilities — current	—	6,901
Interest rate swaps	Derivative liabilities — non-current	—	21,519
Total derivatives designated as hedges		$20,398	$29,971
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$193,431	$154,470
Commodity derivatives	Derivative assets — non-current	22,321	9,032
Commodity derivatives	Derivative liabilities — current	15,944	36,703
Commodity derivatives	Derivative liabilities — non-current	2,460	6,830
Foreign currency derivatives	Derivative liabilities — current	—	11
Interest rate swap	Derivative liabilities — current	—	80,450
Total derivatives not designated as hedges		$234,156	$287,496

As of December 31, 2009

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

As of September 30, 2009

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$6,914	$4,762
Commodity derivatives	Derivative assets — non-current	7	—
Commodity derivatives	Derivative liabilities — current	—	645
Commodity derivatives	Derivative liabilities — non-current	—	9
Interest rate swaps	Derivative liabilities — current	—	6,513
Interest rate swaps	Derivative liabilities — non-current	—	12,941
Total derivatives designated as hedges		$6,921	$24,870
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$201,011	$152,933
Commodity derivatives	Derivative assets — non-current	11,407	5,976
Commodity derivatives	Derivative liabilities — current	10,672	25,803
Commodity derivatives	Derivative liabilities — non-current	1,201	5,742
Interest rate swap	Derivative liabilities — current	—	46,332
Interest rate swap	Derivative liabilities — non-current	—	10,333
Foreign currency derivatives	Derivative liabilities — current	52	—
Foreign currency derivatives	Derivative liabilities — current	58	71
Total derivatives designated as hedges		$224,401	$247,190

Our derivative activities are discussed in Note 13. The following tables present the impact that derivatives had on our Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2010.

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Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged items on our accompanying Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2010 and September 30, 2009 are presented as follows (in thousands):

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income
Fair Value Hedges

Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended September 30, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income	Nine Months Ended September 30, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$10,421	$18,430
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	(10,247)	(18,425)
		$174	$5

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income
Fair Value Hedges

Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended September 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income	Nine Months Ended September 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$3,868	$10,749
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	(2,552)	(8,092)
		$1,316	$2,657

Cash Flow Hedges

The impact of cash flow hedges on our Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2010 and September 30, 2009 are presented as follows (in thousands):

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income and Balance Sheets
Three Months Ended September 30, 2010
Cash Flow Hedges

Derivatives in Cash Flow Hedging	Amount of Gain/(Loss) Recognized	Location of Gain/(Loss) Reclassified	Amount of Reclassified Gain/(Loss)	Location of Gain/(Loss) Recognized	Amount of Gain/(Loss) Recognized in

Relationships	in AOCI Derivative (Effective Portion)	from AOCI into Income (Effective Portion)	from AOCI into Income (Effective Portion)	in Income on Derivative (Ineffective Portion)	Income on Derivative (Ineffective Portion)
Interest rate swaps	$30,227	Interest expense	$(1,859)		$—
Commodity derivatives	(24,912)	Operating revenue	14,540	Operating revenue	(134)
Total	$5,315		$12,681		$(134)

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income and Balance Sheets
Three Months Ended September 30, 2009
Cash Flow Hedges

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 Reclassified Gain/(Loss) 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	$(2,941)	Interest expense	$(582)		$—
Commodity derivatives	(7,781)	Operating revenue	5,976	Operating revenue	(147)
Total	$(10,722)		$5,394		$(147)

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income and Balance Sheets
Nine Months Ended September 30, 2010
Cash Flow Hedges

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	$18,341	Interest expense	(5,683)		$—
Commodity derivatives	(18,822)	Operating revenue	12,592	Operating revenue	(451)
Total	$(481)		$6,909		$(451)

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income and Balance Sheets
Nine Months Ended September 30, 2009
Cash Flow Hedges

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	$8,780	Interest expense	$(2,540)		$—
Commodity derivatives	(16,289)	Operating revenue	19,157	Operating revenue	(1,241)
Total	$(7,509)		$16,617		$(1,241)

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments that have not been designated as hedges on our Condensed Consolidated Statement of Income for the three and nine months ended September 30, 2010 and September 30, 2009 are presented below (in thousands):

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income
Derivatives Not Designated as Hedging Instruments

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended September 30, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income		Nine Months Ended September 30, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income	
Commodity derivatives	Operating revenue	$9,589		$13,798	
Interest rate swap - unrealized	Interest rate swap — unrealized (loss) gain	(13,710	)	(41,663	)
Interest rate swaps - realized	Interest expense	(3,773	)	(9,953	)
Foreign currency contracts	Operating revenue	3		(12	)
		$(7,891	)	$(37,830	)

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income
Derivatives Not Designated as Hedging Instruments

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended September 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income		Nine Months Ended September 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income	
Commodity derivatives	Operating revenue	$(8,531	)	$(25,895	)
Interest rate swap - unrealized	Interest rate swap — unrealized (loss) gain	(8,694	)	37,775	
Interest rate swaps - realized	Interest expense	(3,015	)	(9,816	)
Foreign currency contracts	Operating revenue	374		267	
		$(19,866	)	$2,331	

(15) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair value of our financial instruments at September 30, 2010, December 31, 2009 and September 30, 2009 is as follows (in thousands):

	September 30, 2010		December 31, 2009		September 30, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash, cash equivalents	$58,975	$58,975	$112,901	$112,901	$137,681	$137,681
Restricted cash	$17,082	$17,082	$17,502	$17,502	$6	$6
Derivative financial instruments - assets	$84,450	$84,450	$41,524	$41,524	$62,389	$62,389
Derivative financial instruments - liabilities	$134,210	$134,210	$69,165	$69,165	$96,458	$96,458
Notes payable	$145,000	$145,000	$164,500	$164,500	$350,500	$350,500
Long-term debt, including current maturities	$1,193,607	$1,303,338	$1,051,157	$1,123,703	$751,306	$848,900

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

Cash, Cash Equivalents

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

Restricted Cash

Restricted cash is cash held in escrow:

- A deposit of $6.2 million held in accordance with terms of a settlement at our Oil and Gas segment; and
- Restricted cash accounts required by Black Hills Wyoming project financing agreements total $10.9 million, held in 30-day Guaranteed Investment Certificates.

Derivative Financial Instruments

Derivative Financial instruments are carried at fair value. Our fair value measurements are developed using a variety of inputs by our risk management group, which is independent of the trading function. These inputs include unadjusted quoted prices where available; prices published by various third-party providers; and, when necessary, internally developed adjustments. In many cases, the internally developed prices are corroborated with external sources. Some of our transactions take place in markets with limited liquidity and limited price visibility. Additionally, descriptions of the various instruments we use and the valuation method employed are included in Notes 13 and 14.

Notes Payable

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

Long-Term Debt

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

(16) COMMITMENTS AND CONTINGENCIES

Legal Proceedings

We are subject to various legal proceedings, claims and litigation as described in Note 19 of the Notes to our Consolidated Financial Statements in our 2009 Annual Report on Form 10-K. There are no material proceedings that have developed, no material developments with respect to existing legal proceedings and no material proceedings have terminated during the first nine months of 2010.

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 our 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 below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our consolidated financial statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of September 30, 2010, cannot be reasonably determined and could have a material adverse effect on our results of operations or financial position.

Power Purchase Agreement and Purchase Option Agreement

In March 2010, Black Hills Power entered into a seven-year PPA and Purchase Option Agreement with the City of Gillette, Wyoming effective April 2010 that replaces a previous agreement. This PPA provided the City of Gillette, through JPB, with an option to purchase a 23% ownership interest in Black Hills Power's Wygen III facility which commenced commercial operations on April 1, 2010. The City of Gillette notified Black Hills Power of its intent to exercise the option to purchase the 23% ownership interest in Wygen III and the transaction closed in July 2010. The PPA terminated upon the closing of the transaction.

Guarantees

We issued a guarantee for $6.0 million for a payment obligation arising from a contract to construct and purchase a new office building by Black Hills Utility Holdings. The office building is a 36,000 square foot office building located in Papillion, Nebraska. The guarantee will expire upon purchase of the building which is expected to be completed in 2011.

In May 2010, Black Hills Electric Generation issued a guarantee to the City of Pueblo, Colorado for the lesser of (a) the guaranteed obligations under the Annexation Agreement or (b) $10.0 million for the obligations of Colorado IPP relating to the construction of the 200 MW generation facility. A payment of $2.9 million was made to the City of Pueblo in September 2010 and the guarantee terminated as of September 30, 2010.

We issued a guarantee to Colorado Interstate Gas Company for $9.3 million for payment obligations of Black Hills Utilities Holdings, Inc. related to natural gas transportation, storage and services agreements. The guarantee expires July 31, 2011.

Other Commitments

Construction of a 180 MW power generation facility by our Colorado Electric utility and a 200 MW power generation facility by our Power Generation segment is progressing. Cost of construction is expected to be approximately $250 million to $260 million for Colorado Electric and $240 million to $265 million for the Power Generation segment. Construction is expected to be completed at both facilities by December 31, 2011. As our plans progress, we are in the process of procuring or have procured contracts for the turbines, building construction and labor. As of September 30, 2010, committed contracts for equipment purchases and for construction were 100% and 70% complete, respectively, for the Colorado Electric utility and 94% and 61% complete, respectively, for the Power Generation segment.

(17) INCOME TAXES

Our effective tax rate for the nine months ended September 30, 2010 and for the nine months ended September 30, 2009 was impacted primarily by:

- We recorded a $2.4 million reduction in tax expense reflecting a re-measurement of certain tax positions in accordance with accounting for uncertain tax positions for our Corporate and Oil and Gas segments. The re-measurement was prompted by a settlement agreement that was reached with the IRS Appeals Division in regards primarily to tax depreciation method changes; and

- We filed an application for a method change with the 2008 tax return and received consent from the IRS to make such change 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 continue to be capitalized and depreciated 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. A regulatory asset was established to reflect that future increases in taxes payable will be recovered from customers as the temporary differences reverse. Due to this regulatory treatment, we recorded an income tax benefit of $2.2 million, during the third quarter of 2010 to reflect this change in accounting method for tax purposes, of which approximately $1.0 million, $0.7 million, and $0.5 million relate to 2008, 2009, and 2010 tax years, respectively. For years prior to 2008, we have not recorded a regulatory asset for the repairs deduction as the tax benefit was not flowed through to customers.

- Our effective tax rate for the nine months ended September 30, 2009 was also impacted by a positive adjustment in the first quarter of 2009 for a previously recorded tax position. We recorded a $3.8 million reduction in tax expense reflecting a re-measurement of a tax position in accordance with accounting for uncertain tax positions for our Oil and Gas segment.

(18) IMPAIRMENT OF LONG-LIVED ASSETS

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

(19) SALE OF OPERATING ASSETS

Sale of Gas Assets

In March 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 after-tax gain on the sale.

Partial Sale of Wygen III

On July 14, 2010, Black Hills Power sold a 23% ownership interest in Wygen III to the JPB for $62.0 million. The JPB exists for the purpose of, among other things, financing the electrical system of the City of Gillette. The transaction entitles the City of Gillette to an ownership interest of approximately 25.3 MW in the plant. The purchase terminates the current PPA with the City of Gillette, and the Wygen III Participation Agreement has been amended to include the JPB. 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.

(20) ACQUISITION

On June 1, 2010, Enserco expanded the commodities it markets through the acquisition of a coal marketing business from EDF for $2.25 million. Substantially all of the value of the net assets acquired was related to the portfolio of coal marketing contracts. On the June 1, 2010 acquisition date, the fair value of the net assets was approximately $2.4 million which was recorded in Derivative assets and Derivative liabilities. Additionally, we recognized $0.2 million gain from bargain purchase, which was recorded in Other income, net on the accompanying Condensed Consolidated Income Statements. For the three months ended September 30, 2010, Enserco recorded realized and unrealized gains of $5.2 million and since acquisition, Enserco has recognized $8.9 million of unrealized and realized gains, respectively. Further information regarding these coal marketing contracts and activities is included in Note 13 of the Notes to Condensed Consolidated Financial Statements.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

We are a diversified 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 reportable operating segments:

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

Our Utilities Group consists of our Electric and Gas Utility segments. Our Electric Utilities generate, transmit and distribute electricity to approximately 201,300 customers in South Dakota, Wyoming, Colorado and Montana. In addition, Cheyenne Light, which is also reported within the Electric Utilities segment, provides natural gas to approximately 34,100 customers in Wyoming. Our Gas Utilities serve approximately 518,950 natural gas customers in Colorado, Nebraska, Iowa and Kansas. Our Non-regulated Energy Group engages in the production of coal, natural gas and crude oil primarily in the Rocky Mountain region; the production of electric power through ownership of a portfolio of generating plants and the sale of electric power and capacity primarily under long-term contracts; and the marketing of natural gas, crude oil, coal and related services.

Certain industries in which we operate are highly seasonal and revenues from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market price. In particular, the normal peak usage season for gas utilities is November through March and significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2010, and our financial condition as of September 30, 2010 and December 31, 2009, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period.
See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 82.

Amounts are presented on a pre-tax basis unless otherwise indicated. Minor differences in comparative amounts may result due to rounding.

Significant Events

Wygen III Power Plant

On April 1, 2010, the Wygen III, 110 MW mine-mouth coal-fired power plant commenced commercial operations. As of September 30, 2010, Black Hills Power owned a 52% interest in the facility.

In March 2010, Black Hills Power entered into a seven-year PPA and Purchase Option Agreement with the City of Gillette, Wyoming effective April 2010 that replaced a previous PPA entered into in 1998. This new agreement also provided the City of Gillette, through JPB, with an option to purchase a 23% ownership interest, or approximately

25.3 MW, in Black Hills Power's Wygen III facility. The JPB exists for the purpose of, among other things, financing the electrical system of the City of Gillette. The City of Gillette exercised this option on July 14, 2010 and the JPB purchased the 23% ownership interest in Wygen III for $62.0 million for which Black Hills Power recognized a gain on the sale of $6.2 million. Under the Participation Agreement among the owners of Wygen III, Black Hills Power will continue to operate Wygen III and the City of Gillette will pay Black Hills Power for administrative services and its share in the costs of operating the plant for the life of the facility. The PPA dated March 2010 terminated upon the closing of the transaction.

Energy Marketing

In June 2010, our Energy Marketing segment expanded the commodities it markets to include coal through the acquisition of a coal marketing business for $2.25 million. The business will focus on sourcing coal from Wyoming's Powder River Basin for delivery to customers in the western United States.

Rate Case Settlements

Black Hills Power - South Dakota

In July 2010, the SDPUC approved a final revenue increase of $15.2 million, or 12.7%, for Black Hills Power's South Dakota customers. Interim rates representing a 20% revenue increase were in effect commencing April 1, 2010 and a refund was provided to customers during the third quarter of 2010.

Black Hills Power - Wyoming

In May 2010, the WPSC approved a final revenue increase of $3.1 million for Black Hills Power's Wyoming customers. The new rates were effective June 1, 2010 and a refund was provided to customers during the third quarter of 2010.

Black Hills Energy -Nebraska Gas

In August 2010, NPSC issued a final 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 on or after September 1, 2010. A plan for refund has been filed with the NPSC and we have accrued for the difference between interim and approved rates.

Black Hills Energy - Colorado Electric

In August 2010, the CPUC approved a settlement agreement for an annual revenue increase of $17.9 million, based on a return on equity of 10.5% with a capital structure of 52% equity effective on August 6, 2010.

Black Hills Energy - Iowa Gas

Iowa Gas filed a settlement agreement with the Iowa Utilities Board for a $3.4 million increase in annual revenues. The original rate request was filed with the IUB for a $4.7 million annual increase in utility revenues on June 8, 2010. Interim rates reflecting an annual utility revenue increase of $2.6 million were implemented on June 18, 2010, and will be adjusted after the IUB issues a final rate order.

Smart Grid Funding

In April 2010, we reached an agreement with the DOE for smart grid funding through grants totaling $20.7 million for our Electric Utilities. The funds are made available through the American Recovery and Reinvestment Act of 2009 and combined with matching investments from us will enable our electric utilities to install smart meters and make related infrastructure investments. We have completed 63% of the installations related to the grant as of September 30, 2010. Our utilities expect to complete installation of these meters in 2011.

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Suspension of Operations at Osage Plant

Black Hills Power suspended operations at its Osage plant beginning October 1, 2010. Osage is a 34.5 MW coal-fired plant which was put into operations in 1948. Osage will remain an asset in the generation portfolio and maintain all operating permits so the plant will have the ability to resume full operations, if needed.

Tax Matters

During the quarter, the effective tax rate at our Electric Utilities Segment decreased primarily as a result of a $2.2 million tax benefit for a repairs deduction taken for tax purposes and the flow-through treatment of the associated tax benefit resulting from a rate case settlement. This decrease in the company's effective tax rate is partially offset by a lower tax benefit from AFUDC-equity which decreased upon commercial operations of Wygen III; 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. The re-measurement was prompted by a settlement agreement that was reached with the IRS Appeals Division primarily in regards to a tax depreciation method change involving certain assets sold in the IPP Transaction.

Results of Operations

Executive Summary and Overview

Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009. Income from continuing operations for the three months ended September 30, 2010 was $12.4 million, or $0.32 per share, compared to Loss from continuing operations of $3.9 million, or $0.10 per share, reported for the same period in 2009. The 2010 Income from continuing operations includes a $4.1 million after-tax gain on the sale of a 23% ownership interest in Wygen III, an $8.9 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps, and a $2.4 million tax adjustment for a re-measurement of certain tax positions. The 2009 Loss from continuing operations included a $5.7 million after-tax unrealized mark-to-market loss on these same interest rate swaps and integration costs of $0.8 million.

Net income was $12.4 million, or $0.32 per share, in the three months ended September 30, 2010, compared to Net loss of $2.2 million, or $0.06 per share, for the same period in 2009. In addition to the items mentioned above in Income from continuing operations, the 2009 Net loss also includes $1.7 million of after-tax income from discontinued operations related to the operations sold in the IPP Transaction.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009. Income from continuing operations for the nine months ended September 30, 2010 was $35.2 million, or $0.90 per share, compared to $46.4 million, or $1.20 per share, reported for the same period in 2009. The 2010 Income from continuing operations includes a $4.1 million after-tax gain on sale of 23% ownership interest in Wygen III, a $2.4 million tax adjustment for a re-measurement of certain tax positions, a $1.7 million after-tax gain on the sale of assets by Nebraska Gas and a $27.1 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps. The 2009 Income from continuing operations includes a $24.6 million after-tax mark-to-market gain on these same interest rate swaps, a $27.8 million after-tax non-cash ceiling test impairment, a $16.9 million after-tax gain on the sale of a 23.5% ownership interest in Wygen I, a $3.8 million tax adjustment for a re-measurement of a tax position, integration costs of $2.4 million and $1.9 million write-off of the acquisition facility fees.

Net income was $35.2 million, or $0.90 per share, in the first nine months of 2010, compared to $48.8 million, or $1.26 per share, for the same period in 2009. In addition to the items mentioned above in Income from continuing operations, the 2009 Net income also included $2.4 million of after-tax income from discontinued operations related to the operations sold in the IPP Transaction.

Business Group highlights are as follows:

Utilities Group

The Utilities Group's Income from continuing operations for the first nine months of 2010 was $53.6 million, compared to $38.6 million for the same period in 2009. 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 not in effect for the entire year of 2009. Additional highlights of the Utilities Group include the following:

- 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 JPB for $62.0 million. A gain of $6.2 million was recognized on the sale. The JPB exists for the purpose of, among other things, financing the electric system of the City of Gillette, Wyoming. Under the terms of the purchase agreement, the City of Gillette will pay Black Hills Power for ongoing administrative services and share in the cost of operating the plant for the life of the facility;

- In September 2009, Black Hills Power filed a request with the SDPUC for annual revenue increases of $32.0 million to recover the costs associated with Wygen III and increases in other costs. On July 7, 2010, the SDPUC approved new rates representing an increase of $15.2 million in annual revenues which were effective retroactive to April 1, 2010;
- In October 2009, Black Hills Power filed a rate request with the WPSC for annual revenue increases of $3.8 million. On May 13, 2010, WPSC approved a rate increase of $3.1 million effective June 1, 2010;
- In January 2010, Colorado Electric filed a request with the CPUC seeking a $22.9 million increase in annual revenues. On August 5, 2010, the CPUC approved a settlement agreement for $17.9 million in annual revenues, with an effective date of August 6, 2010;

- In June 2010, Iowa Gas filed a request for a $4.7 million increase in annual revenues with the IUB. An interim rate increase equal to $2.4 million, or 1.6%, of revenues went into effect on June 18, 2010;

- In December 2009, Nebraska Gas filed a $12.1 million increase in annual revenues with the NPSC. Interim rates subject to refund went into effect on March 1, 2010. The NPSC approved a final increase of $8.3 million in annual revenues effective September 1, 2010;

- 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 beginning October 1, 2010. The Osage plant consumed 142,350 tons of coal during the first nine months of 2010 and 247,100 tons of coal during 2009. We now have more economical power supply alternatives available to provide for present customer energy demands; however, the plant's operating permits will be retained so that full operations can be restored if needed;

- During the quarter, the effective tax rate decreased primarily as a result of a $2.2 million tax benefit for a repairs deduction taken for tax purposes and the flow-through treatment of the associated tax benefit resulting from a rate case settlement. This decrease in the company's effective tax rate is partially offset by a lower tax benefit from AFUDC-equity which decreased upon commercial operations of Wygen III;

- 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 September 30, 2010, we have completed 63% of the installations related to these meters. We expect to have expended all grant funds by the end of 2011;

- Construction of gas-fired generation to serve Colorado Electric customers is moving forward to start providing energy on January 1, 2012. The 180 MW generation project is expected to cost between $250 million and $260 million, of which $130.7 million has been expended through September 30, 2010. Construction commenced in July 2010 subsequent to the City of Pueblo annexing our site into the city and the receipt of the final air permit from the State of Colorado Department of Public Health and Environment; and

- Due to the annexation of an outlying suburb by the City of Omaha, Nebraska, Nebraska Gas sold assets serving approximately 3,000 customers to Metropolitan Utilities District on March 2, 2010. Nebraska Gas received $6.1 million in cash and recognized a $1.7 million after-tax gain on the sale of assets in the first quarter of 2010.

Non-regulated Energy Group

Income from continuing operations was $15.8 million for the first nine months of 2010 for the Non-regulated Energy Group compared to a Loss from continuing operations of $5.5 million in the same period in 2009. Highlights of the Non-regulated Energy Group include the following:

- Construction of gas-fired generation at Colorado IPP to serve a 20-year PPA with Colorado Electric is moving forward to start providing energy on January 1, 2012. The 200 MW project is expected to cost between $240 million and $265 million, of which $104.9 million has been expended through September 30, 2010. Construction commenced in July 2010 subsequent to the City of Pueblo annexing our site into the city and the receipt of the final air permit from the State of Colorado Department of Public Health and Environment;

- During the third quarter of 2010, Enserco expanded business lines to include power and environmental marketing. The expansion does not have a material impact on credit facility utilization and our risk tolerances and capital allocated to the energy marketing segment are expected to remain the same;

- In June 2010, Enserco expanded the commodities it markets through the acquisition of a coal marketing business for $2.25 million;
- In May 2010, Enserco entered into a two-year $250 million committed stand-alone credit facility. The new facility includes a $100 million accordion feature;

- 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. The write-down of gas and oil properties was based on period-end NYMEX prices of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas; and $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil.

Corporate

Loss from continuing operations was $34.2 million for the first nine months of 2010 compared to Income from continuing operations of $13.2 million in the same period in 2009. Highlights of the Corporate activities include the following:

- We recognized a non-cash unrealized mark-to-market loss related to certain interest rate swaps of $41.7 million for the first nine months of 2010 compared to a $37.8 million unrealized gain on these swaps for the same period in 2009;
- On April 15, 2010, we entered into a new three-year $500 million Revolving Credit Facility, which includes a $100 million accordion feature, that will be used to fund working capital needs and for other corporate purposes. The new facility replaces the Corporate Credit Facility which terminated on April 15, 2010;
- On July 16, 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%; 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. The re-measurement was prompted by a settlement agreement that was reached with the IRS Appeals Division primarily in regards to tax depreciation method changes.

Consolidated Results

Revenues, Income (loss) from continuing operations, and Net income (loss) provided by each business group were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Revenues				
Utilities	$214,910	$191,634	$829,327	$796,973
Non-regulated Energy	49,445	34,165	148,651	124,117
	$264,355	$225,799	$977,978	$921,090
Income (loss) from continuing operations				
Utilities	$17,942	$7,053	$53,601	$38,618
Non-regulated Energy	4,541	(1,796)	15,785	(5,470)
Corporate	(10,093)	(9,110)	(34,221)	13,205
	$12,390	$(3,853)	$35,165	$46,353
Net income (loss)				
Utilities	$17,942	$8,726	$53,601	$40,291
Non-regulated Energy	4,541	(1,796)	15,785	(5,470)
Corporate	(10,093)	(9,110)	(34,221)	13,971
	$12,390	$(2,180)	$35,165	$48,792

Income from continuing operations increased $16.2 million for the three months ended September 30, 2010 reflecting the following:

Utilities

- An $8.0 million increase in Electric Utilities earnings;
- A $2.9 million increase in the Gas Utilities earnings;

Non-regulated Energy

- A $1.0 million increase in Oil and Gas earnings;
- A $0.6 million decrease in Coal Mining earnings;
- A $5.9 million increase in Energy Marketing earnings;
- Power Generation earnings are comparable to third quarter of 2009; and

Corporate

- A $1.0 million increase in unallocated Corporate expenses.

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Income from continuing operations decreased $11.2 million for the nine months ended September 30, 2010 reflecting the following:

Utilities

- An $11.2 million increase in Electric Utilities earnings;
- A $3.8 million increase in the Gas Utilities earnings;

Non-regulated Energy

- A $29.1 million increase in Oil and Gas earnings;
- A $3.5 million increase in Coal Mining earnings;
- A $5.8 million increase in Energy Marketing earnings;
- A $17.2 million decrease in Power Generation earnings; and

Corporate

- A $47.4 million increase in unallocated Corporate expenses.

Following are additional details regarding the results of operations from our Utilities and Non-regulated Energy Groups by business segment, and Corporate activities.

The following business group and segment information does not include intercompany eliminations or results of discontinued operations.

Utilities Group

We report two segments within the Utilities Group: Electric Utilities and Gas Utilities. The Electric Utilities segment includes the electric operations of Black Hills Power, Colorado Electric and the electric and natural gas operations of Cheyenne Light. The Gas Utilities segment includes the regulated natural gas utility operations of Black Hills Energy in Colorado, Nebraska, Iowa and Kansas.

Electric Utilities

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Revenue — electric	$138,122	$126,025	$399,298	$361,198
Revenue — gas	3,523	3,141	27,421	24,062
Total revenue	141,645	129,166	426,719	385,260
Fuel and purchased power — electric	67,104	66,994	205,409	190,831
Purchased gas	1,157	912	16,929	13,873
Total fuel and purchased power	68,261	67,906	222,338	204,704
Gross margin — electric	71,018	59,031	193,889	170,367
Gross margin — gas	2,366	2,229	10,492	10,189
Total gross margin	73,384	61,260	204,381	180,556
Operating, general and administrative costs	33,428	31,811	102,152	96,098
Gain on sale of operating assets	(6,238)	—	(6,238)	—
Depreciation and amortization	12,481	10,682	35,567	32,605
Total operating expenses	39,671	42,493	131,481	128,703
Operating income	33,713	18,767	72,900	51,853
Interest expense, net	(10,573)	(7,097)	(27,275)	(24,082)
Other income	400	2,579	2,840	6,110
Income tax expense	(5,003)	(3,712)	(12,880)	(9,486)
Income from continuing operations and net income	$18,537	$10,537	$35,585	$24,395

The following tables summarize revenues, quantities generated and purchased, sales quantities and degree days for our Electric Utilities segment:

Revenues (in thousands)	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009
Residential:				
Black Hills Power	$13,492	$11,132	$39,517	$35,804
Cheyenne Light	7,235	6,512	21,945	21,093
Colorado Electric	21,674	18,586	57,697	50,274
Total Residential	42,401	36,230	119,159	107,171
Commercial:				
Black Hills Power	18,529	15,694	49,172	44,888
Cheyenne Light	14,379	13,424	40,251	38,050
Colorado Electric	17,833	15,088	49,528	42,259
Total Commercial	50,741	44,206	138,951	125,197
Industrial:				
Black Hills Power	5,402	4,714	16,243	14,494
Cheyenne Light	2,156	2,888	7,568	8,179
Colorado Electric	7,606	8,021	21,391	23,074
Total Industrial	15,164	15,623	45,202	45,747
Municipal:				
Black Hills Power	850	778	2,251	2,074
Cheyenne Light	419	230	887	701
Colorado Electric	3,130	1,179	7,688	3,351
Total Municipal	4,399	2,187	10,826	6,126
Contract Wholesale:				
Black Hills Power	4,758	6,488	18,554	18,672
Off-system Wholesale:				
Black Hills Power	9,695	9,625	26,950	24,610
Cheyenne Light	2,545	1,863	7,255	5,795
Colorado Electric	506	2,697	10,742	9,724
Total Off-system Wholesale	12,746	14,185	44,947	40,129
Other:				
Black Hills Power	6,325	4,655	17,291	13,838
Cheyenne Light	773	253	2,474	466
Colorado Electric	815	2,198	1,894	3,852
Total Other	7,913	7,106	21,659	18,156
Total Revenues	$138,122	$126,025	$399,298	$361,198

Quantities Generated and Purchased (in MWh)	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009
Generated —				
Coal-fired:				
Black Hills Power	525,000	465,068	1,514,831	1,251,276
Cheyenne Light	196,079	200,489	553,978	577,217
Colorado Electric	66,951	63,760	193,195	187,091
Total Coal	788,030	729,317	2,262,004	2,015,584
Gas and Oil-fired:				
Black Hills Power	11,780	28,251	15,724	35,076
Cheyenne Light	—	—	—	—
Colorado Electric	1,061	2,297	1,154	2,496
Total Gas and Oil-fired	12,841	30,548	16,878	37,572
Total Generated:				
Black Hills Power	536,780	493,319	1,530,555	1,286,352
Cheyenne Light	196,079	200,489	553,978	577,217
Colorado Electric	68,012	66,057	194,349	189,587
Total Generated	800,871	759,865	2,278,882	2,053,156
Purchased —				
Black Hills Power	314,924	420,332	1,035,124	1,304,362
Cheyenne Light	166,082	151,992	510,509	464,265
Colorado Electric	540,192	514,980	1,569,350	1,495,825
Total Purchased	1,021,198	1,087,304	3,114,983	3,264,452
Total Generated and Purchased:				
Black Hills Power	851,704	913,651	2,565,679	2,590,714
Cheyenne Light	362,161	352,481	1,064,487	1,041,482
Colorado Electric	608,204	581,037	1,763,699	1,685,412
Total Generated and Purchased	1,822,069	1,847,169	5,393,865	5,317,608

Quantity Sold (in MWh)	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009
Residential:				
Black Hills Power	122,123	113,266	410,561	395,865
Cheyenne Light	62,150	59,384	196,122	189,610
Colorado Electric	180,771	166,993	485,381	444,223
Total Residential	365,044	339,643	1,092,064	1,029,698
Commercial:				
Black Hills Power	195,634	207,939	544,935	553,150
Cheyenne Light	170,523	152,376	459,647	439,476
Colorado Electric	201,989	187,959	554,584	507,123
Total Commercial	568,146	548,274	1,559,166	1,499,749
Industrial:				
Black Hills Power	90,426	80,222	278,514	260,190
Cheyenne Light	32,943	45,447	117,373	131,694
Colorado Electric	95,795	121,789	265,789	342,206
Total Industrial	219,164	247,458	661,676	734,090
Municipal:				
Black Hills Power	9,008	9,894	24,811	25,556
Cheyenne Light	2,223	742	3,836	2,449
Colorado Electric	36,465	11,705	85,881	29,696
Total Municipal	47,696	22,341	114,528	57,701
Contract Wholesale:				
Black Hills Power	83,013	161,796	371,736	473,723
Off-system Wholesale:				
Black Hills Power	309,297	309,770	839,408	784,173
Cheyenne Light	86,675	72,771	234,937	216,822
Colorado Electric	59,453	71,886	292,741	272,694
Total Off-system Wholesale	455,425	454,427	1,367,086	1,273,689
Total Quantity Sold:				
Black Hills Power	809,501	882,887	2,469,965	2,492,657
Cheyenne Light	354,514	330,720	1,011,915	980,051
Colorado Electric	574,473	560,332	1,684,376	1,595,942
Total Quantity Sold	1,738,488	1,773,939	5,166,256	5,068,650
Losses and Company Use:				
Black Hills Power	42,203	30,764	95,714	98,057
Cheyenne Light	7,647	21,761	52,572	61,431
Colorado Electric	33,731	20,705	79,323	89,470
Total Losses and Company Use	83,581	73,230	227,609	248,958

Total Energy	1,822,069	1,847,169	5,393,865	5,317,608

Degree Days	Three Months Ended September 30, 2010		2009	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Actual —				
Black Hills Power	188	(17)%	178	(22)%
Cheyenne Light	159	(51)%	298	(9)%
Colorado Electric	11	(88)%	104	13%
Cooling Degree Days:				
Actual —				
Black Hills Power	456	(8)%	303	(39)%
Cheyenne Light	310	34%	179	(23)%
Colorado Electric	793	13%	620	(12)%

Degree Days	Nine Months Ended September 30, 2010		2009	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Actual —				
Black Hills Power	4,484	(3)%	4,705	4%
Cheyenne Light	4,577	(3)%	4,383	(7)%
Colorado Electric	3,435	2%	3,053	(10)%
Cooling Degree Days:				
Actual —				
Black Hills Power	521	(12)%	354	(41)%
Cheyenne Light	345	26%	203	(26)%
Colorado Electric	1,073	17%	804	(13)%

	Electric Utilities Power Plant Availability			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Coal-fired plants	95.9% (a)	94.5%	93.2%	92.0%
Other plants	98.5%	96.5% (b)	98.5%	96.1% (b)
Total availability	96.8%	96.8%	95.1%	93.6%

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(a) Reflects addition of Wygen III which commenced commercial operations on April 1, 2010. Wygen III's availability during the three and nine months ended September 30, 2010 was 96.6% and 91.2%, respectively.

(b) Reflects unplanned outage at Pueblo Unit 5 gas-fired plant.

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Cheyenne Light Natural Gas Distribution

Included in the Electric Utilities segment is Cheyenne Light's natural gas distribution system. The following table summarizes certain operating information of these natural gas distribution operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Revenues (in thousands):				
Residential	$2,359	$2,053	$16,642	$14,699
Commercial	736	657	7,791	6,716
Industrial	257	266	2,378	2,073
Other	171	165	610	574
Total Revenues	$3,523	$3,141	$27,421	$24,062
Gross Margins (in thousands):				
Residential	$1,779	$1,624	$7,329	$6,990
Commercial	372	379	2,341	2,296
Industrial	49	61	276	329
Other	166	165	546	574
Total Gross Margins	$2,366	$2,229	$10,492	$10,189
Volumes Sold (Dth):				
Residential	173,430	176,996	1,868,609	1,745,760
Commercial	111,643	120,348	1,104,484	1,037,984
Industrial	76,056	79,161	453,601	462,276
Total Volumes Sold	361,129	376,505	3,426,694	3,246,020

Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009. Income from continuing operations was $18.5 million for the three months ended September 30, 2010 compared to $10.5 million for the three months ended September 30, 2009 as a result of:

Gross margin: Gross margin increased $12.1 million primarily due to an increase of $8.1 million related to the impact of the outcome of the Black Hills Power and Colorado Electric rate cases during 2010, an increase of $0.9 million for updated transmission cost adjustments at Colorado Electric, an increase of $1.9 million in off-system sales margins resulting from lower costs to serve off-system sales, and an increase of $0.9 million associated with an intercompany shared services agreement.

Operating, general and administrative costs: Operating, general and administrative costs increased $1.6 million primarily due to additional costs of $1.4 million associated with Wygen III which commenced commercial operations on April 1, 2010 and increased intercompany costs of $1.4 million associated with a shared services agreement partially offset by a decrease in property taxes.

Gain on sale of operating assets: The gain on sale of operating assets of $6.2 million represents the sale of a 23% ownership interest in the Wygen III generating facility to the City of Gillette.

Depreciation and amortization: Depreciation and amortization increased $1.8 million primarily due to commencement of depreciation on the Wygen III plant which began commercial operations on April 1, 2010.

Interest expense, net: Interest expense, net increased $3.5 million due to higher interest expense of $4.0 million compared to the same period in the prior year resulting from higher rates on long-term debt compared to short-term debt partially offset by an increase of $0.6 million for AFUDC-borrowed associated with the borrowed funds for the Colorado Electric plant construction.

Other income: Other income decreased $2.2 million primarily due to lower AFUDC-equity which decreased upon the placement of Wygen III into commercial operations on April 1, 2010.

Income tax expense: The effective tax rate decreased primarily as a result of a $2.2 million tax benefit for a repairs deduction taken for tax purposes and the flow-through treatment of the associated tax benefit resulting from a rate case settlement partially offset by lower tax benefit from AFUDC-equity which decreased upon commercial operations of Wygen III.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009. Income from continuing operations was $35.6 million in the first nine months of 2010 compared to $24.4 million in the first nine months of 2009 as a result of:

Gross margin: Gross margin increased $23.8 million primarily due to a $14.2 million increase related to the impact of the outcome of the Black Hills Power and Colorado rate cases, an increase of $2.6 million for updated transmission cost adjustments at Colorado Electric, a $4.6 million increase in off-system sales margin resulting from lower costs to serve off-system sales, and a $3.7 million increase in intercompany revenues from a shared services agreement.

Operating, general and administrative costs: Operating, general and administrative costs increased $6.1 million primarily due to costs of $2.7 million associated with Wygen III which commenced commercial operation on April 1, 2010, an increase in labor and employee benefit costs, and an increase of $4.0 million in intercompany costs from a shared services agreement.

Gain on sale of operating assets: The gain on sale of operating assets of $6.2 million represents the sale of a 23% ownership interest in Wygen III generating facility to the City of Gillette.

Depreciation and amortization: Depreciation and amortization increased $3.0 million primarily due to commencement of depreciation on the Wygen III plant placed into service on April 1, 2010.

Interest expense, net: Interest expense, net increased $3.2 million due to higher interest expense of $7.8 million compared to the same period in the prior year resulting from higher long-term debt compared to short-term debt partially offset by an increase of $4.7 million for AFUDC-borrowed associated with the borrowed funds for the Colorado Electric plant construction.

Other income: Other income decreased $3.3 million primarily due to decreased AFUDC-equity associated with the construction of our Wygen III facility.

Income tax expense: The effective tax rate decreased primarily as a result of a $2.2 million tax benefit for a repairs deduction taken for tax purposes and the flow-through treatment of the associated tax benefit resulting from a rate case settlement partially offset by lower benefit from AFUDC-equity which decreased upon commercial operations of Wygen III.

Gas Utilities

Operating results for the Gas Utilities are as follows (in thousands):

	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009
Sales revenue:				
Natural gas — regulated	$64,109	$56,854	$379,291	$392,595
Other — non-regulated services	8,214	5,837	23,317	19,771
Total sales revenue	72,323	62,691	402,608	412,366
Cost of sales:				
Natural gas — regulated	27,804	23,376	230,555	251,252
Other — non-regulated services	5,729	2,894	13,501	11,295
Total cost of sales	33,533	26,270	244,056	262,547
Gross margin	38,790	36,421	158,552	149,819
Operating, general and administrative costs	26,957	30,291	93,406	93,523
Gain on sale of operating assets	—	—	(2,683)	—
Depreciation and amortization	5,711	7,365	19,530	23,045
Total operating expenses	32,668	37,656	110,253	116,568
Operating income (loss)	6,122	(1,235)	48,299	33,251
Interest expense, net	(6,983)	(4,076)	(19,992)	(10,645)
Other expense	(7)	(76)	42	(195)
Income tax benefit (expense)	273	1,903	(10,332)	(8,188)
(Loss) income from continuing operations and net (loss) income	$(595)	$(3,484)	$18,017	$14,223

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The following table summarizes regulated Gas Utilities' revenues (in thousands):

Revenues	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Residential:				
Colorado	$5,104	$5,127	$38,553	$43,277
Nebraska	13,134	12,552	86,904	90,698
Iowa	11,239	9,773	74,814	81,184
Kansas	7,711	7,703	51,640	49,591
Total Residential	37,188	35,155	251,911	264,750
Commercial:				
Colorado	1,156	1,131	8,384	9,444
Nebraska	3,441	2,896	30,101	31,219
Iowa	4,881	3,950	33,894	36,325
Kansas	2,048	1,976	16,352	15,542
Total Commercial	11,526	9,953	88,731	92,530
Industrial:				
Colorado	920	450	1,213	1,159
Nebraska	441	345	2,582	2,435
Iowa	183	307	1,366	958
Kansas	8,831	5,764	13,166	10,349
Total Industrial	10,375	6,866	18,327	14,901
Transportation:				
Colorado	95	115	546	477
Nebraska	1,735	1,519	8,308	7,441
Iowa	746	793	2,704	2,837
Kansas	1,222	1,251	4,206	4,047
Total Transportation	3,798	3,678	15,764	14,802
Other:				
Colorado	22	24	78	82
Nebraska	396	406	1,492	1,592
Iowa	95	109	677	802
Kansas	709	663	2,311	3,136
Total Other	1,222	1,202	4,558	5,612
Total Regulated	64,109	56,854	379,291	392,595
Non-regulated Services	8,214	5,837	23,317	19,771
Total Revenues	$72,323	$62,691	$402,608	$412,366

The following table summarizes regulated Gas Utilities' gross margins (in thousands):

Gross Margins	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Residential:				
Colorado	$2,710	$2,895	$13,265	$11,577
Nebraska	9,019	7,637	35,069	31,767
Iowa	8,053	7,075	32,128	31,237
Kansas	5,385	5,433	21,677	20,781
Total Residential	25,167	23,040	102,139	95,362
Commercial:				
Colorado	462	515	2,372	2,130
Nebraska	1,542	1,357	8,720	8,298
Iowa	1,895	1,706	8,524	9,022
Kansas	991	1,021	4,771	4,516
Total Commercial	4,890	4,599	24,387	23,966
Industrial:				
Colorado	218	141	309	325
Nebraska	60	64	294	276
Iowa	27	26	145	116
Kansas	976	834	1,639	1,584
Total Industrial	1,281	1,065	2,387	2,301
Transportation:				
Colorado	95	114	546	476
Nebraska	1,735	1,520	8,308	7,441
Iowa	746	793	2,704	2,838
Kansas	1,222	1,251	4,219	4,048
Total Transportation	3,798	3,678	15,777	14,803
Other:				
Colorado	22	25	78	82
Nebraska	396	404	1,491	1,591
Iowa	95	110	678	803
Kansas	656	559	1,799	2,496
Total Other	1,169	1,098	4,046	4,972
Total Regulated	36,305	33,480	148,736	141,404
Non-regulated Services	2,485	2,941	9,816	8,415
Total Gross Margins	$38,790	$36,421	$158,552	$149,819

The following table summarizes regulated Gas Utilities' volumes sold (in Dth):

Volumes Sold	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Residential:				
Colorado	415,476	505,857	4,386,492	3,998,997
Nebraska	795,150	909,794	8,515,902	8,349,868
Iowa	611,373	605,788	7,205,381	7,558,458
Kansas	430,282	542,182	4,835,615	4,551,485
Total Residential	2,252,281	2,563,621	24,943,390	24,458,808
Commercial:				
Colorado	121,682	142,070	1,046,490	945,349
Nebraska	378,760	366,579	3,576,684	3,567,604
Iowa	568,192	499,487	4,275,759	4,233,967
Kansas	198,604	230,693	1,887,456	1,759,774
Total Commercial	1,267,238	1,238,829	10,786,389	10,506,694
Industrial:				
Colorado	182,467	110,474	232,123	241,267
Nebraska	87,531	79,710	425,171	394,475
Iowa	29,875	63,646	207,376	154,329
Kansas	1,677,072	1,401,415	2,494,629	2,402,633
Total Industrial	1,976,945	1,655,245	3,359,299	3,192,704
Transportation:				
Colorado	88,106	110,158	563,325	541,958
Nebraska	5,782,468	5,222,591	19,331,381	18,637,020
Iowa	3,802,931	3,069,669	13,059,843	10,375,438
Kansas	3,982,029	3,756,752	11,284,332	10,774,330
Total Transportation	13,655,534	12,159,170	44,238,881	40,328,746
Other:				
Colorado	—	—	—	—
Nebraska	3,315	5	4,464	1,140
Iowa	7,250	3,833	59,779	52,341
Kansas	2	21,360	70,855	98,878
Total Other	10,567	25,198	135,098	152,359
Total volumes	19,162,565	17,642,063	83,463,057	78,639,311

Natural gas in storage at our Gas Utilities represents primarily gas purchased for use by our customers. Natural gas volumes held in storage by us fluctuate with the seasonality of our business and the commodity price of natural gas, and the carrying values are impacted by price fluctuations. Volumes held were as follows (in MMBtu):

	As of September 30, 2010	As of December 31, 2009	As of September 30, 2009
Natural gas in storage	8,582,287	6,866,550	8,598,428

Degree Days	Three Months Ended September 30, 2010		Nine Months Ended September 30, 2010	
Heating Degree Days:	Actual	Variance From Normal	Actual	Variance From Normal
Colorado	29	(85)%	3,722	(4)%
Nebraska	56	(38)%	3,923	2%
Iowa	148	(6)%	4,229	(8)%
Kansas*	8	(79)%	3,126	3%
Combined Gas Utilities Heating Degree Days	58	(48)%	3,819	(2)%

Degree Days	Three Months Ended September 30, 2009		Nine Months Ended September 30, 2009	
Heating Degree Days:	Actual	Variance From Normal	Actual	Variance From Normal
Colorado	224	20%	3,735	(1)%
Nebraska	100	10%	3,645	3%
Iowa	142	(8)%	4,353	3%
Kansas*	67	68%	2,765	(10)%
Combined Gas Utilities Heating Degree Days	141	5%	3,831	(5)%

* Kansas Gas has a 30-year weather normalization adjustment mechanism in place that neutralizes the impact of weather on revenues at Kansas Gas.

Our Gas Utilities are highly seasonal and sales volumes vary considerably with weather and seasonal heating and industrial loads. Over 70% of our Gas Utilities' revenues and margins are expected in the fourth and first quarters of each year. Therefore, revenues for and certain expenses of, these operations fluctuate significantly among quarters. Depending upon the state jurisdiction, the winter heating season begins around November 1 and ends around March 31.

Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009. Loss from continuing operations was $0.6 million in the three months ended September 30, 2010 compared to Loss from continuing operations of $3.5 million in the three months ended September 30, 2009 as a result of:

Gross margin: Gross margins increased $2.4 million primarily due to increased interim rates at Iowa Gas, approved rates at Nebraska Gas, and an approved Gas System Reliability surcharge at Kansas Gas which were effective subsequent to the third quarter of 2009, partially offset by lower volumes.

Operating, general and administrative costs: Operating, general and administrative costs decreased $3.3 million primarily due to decreases in labor and employee benefit costs.

Depreciation and amortization: Depreciation and amortization decreased $1.7 million primarily due to assets that became fully depreciated during 2009 and 2010.

Interest expense, net: Interest expense, net increased $2.9 million primarily resulting from the assignment of longer-term debt to adjust the assigned capital structure.

Other expense: Other expense was comparable to the same period in the prior year.

Income tax benefit (expense): The effective tax rate for the three months ended September 30, 2010 was comparable to the same period in the prior year.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009. Income from continuing operations was $18.0 million in the first nine months of 2010 compared to $14.2 million in the first nine months of 2009 as a result of:

Gross margin: Gross margins increased $8.7 million due to higher volumes on more heating degree days and increased interim rates at Iowa Gas, approved rates at Nebraska Gas, approved rates at Colorado Gas, and an approved Gas System Reliability surcharge at Kansas Gas which were effective subsequent to the third quarter of 2009.

Operating, general and administrative costs: Operating, general and administrative costs were comparable to the same period in the prior year.

Gain on sale of operating assets: The gain on sale of operating assets of $2.7 million represents assets sold by Nebraska Gas to the City of Omaha, Nebraska after a portion of Nebraska Gas' service territory was annexed by the City.

Depreciation and amortization: Depreciation and amortization decreased $3.5 million primarily due to assets becoming fully depreciated during 2009 and 2010.

Interest expense, net: Interest expense, net increased $9.3 million primarily due to the assignment of debt to adjust the assigned capital structure and an increased interest rate associated with the assignment of longer-term debt.

Other expense: Other expense was comparable to the same period in the prior year.

Income tax expense: The effective tax rate for the nine months ended September 30, 2010 was comparable to the same period in the prior year.

Regulatory Matters — Utilities Group

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

								Approved Capital Structure			
	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved	Return on Equity		Equity		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	Pending	$4.7	Pending	Pending		Pending		Pending	
Colorado Gas	Gas	6/2008	4/2009	$2.7	$1.4	10.3	%	50.5	%	49.5	%
Kansas Gas	Gas	5/2009	10/2009	$0.5	$0.5	10.2	%	50.7	%	49.3	%
Black Hills Power (3)	Electric	9/2008	1/2009	$4.5	$3.8	10.8	%	57.0	%	43.0	%
Black Hills Power (4)	Electric	9/2009	4/2010	$32.0	$15.2	Black Box		Black Box		Black Box	
Black Hills Power (5)	Electric	10/2009	6/2010	$3.8	$3.1	10.5	%	52.0	%	48.0	%
Colorado Electric (6)	Electric	1/2010	8/2010	$22.9	$17.9	10.5	%	52.0	%	48.0	%

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

(2) On June 8, 2010, Iowa Gas filed a request with the IUB for a $4.7 million, or 2.9%, revenue increase to recover the cost of capital investments we 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, or 1.6%, 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 and hearings on the settlement were held in October 2010. Approval from the IUB is pending.

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

(4) On September 30, 2009, Black Hills Power filed a rate case with the SDPUC requesting an electric revenue increase to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses incurred during the past four years. Black Hills Power requested a $32.0 million, or 26.6%, increase in annual utility revenues. In March 2010, the SDPUC approved a 20% increase in interim revenues, 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, or 12.7%, and a base rate increase of $22 million, or 19.4% with an effective date of April 1, 2010. The approved capital structure and return on equity are confidential.
As part of the settlement stipulation, Black Hills Power agreed (1) to credit customers 65% of off-system income with a minimum of $2.0 million per year; (2) that rates will include a SD Surplus Energy Credit of $2.5 million in year one (fiscal year ending March 2011), $2.25 million in year two, $2.0 million in year three and zero thereafter; and (3) a moratorium until April 2013 for any base rate increases excluding any extraordinary events as defined in the stipulation agreement.

(5) On October 19, 2009, Black Hills Power filed a rate case with the WPSC requesting an electric revenue increase of $3.8 million 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. Rates went into effect on June 1, 2010.

(6) On January 5, 2010, Colorado Electric filed a rate case with 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. Colorado Electric requested a $22.9 million, or approximately 12.8%, increase in annual revenues. On August 5, 2010, the CPUC approved a settlement agreement for $17.9 million in annual revenues with a return on equity of 10.5% and a capital structure of 52% equity and 48% debt. New rates were effective August 6, 2010.

Included in the rate case order was a provision that off-system sales margins be shared with customers commencing August 1, 2010. The percentage of margin to be shared with the customers was not resolved at the time of the rate case settlement. The CPUC has therefore required that the off-system margins earned beginning August 1, 2010 be deferred on the balance sheet until settlement of the sharing mechanism. Colorado Electric is preparing a proposal for a sharing mechanism to be filed by the end of the year.

Non-regulated Energy Group

An analysis of results from our Non-regulated Energy Group's operating segments follows (in thousands):

Oil and Gas

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Revenue	$19,354	$17,887	$57,755	$52,227
Operating, general and administrative costs	9,731	9,914	29,964	29,982
Depreciation, depletion and amortization	7,326	7,143	20,279	22,281
Impairment of long-lived assets	—	—	—	43,301
Total operating expenses	17,057	17,057	50,243	95,564
Operating income (loss)	2,297	830	7,512	(43,337)
Interest expense	(1,565)	(1,096)	(3,738)	(3,549)
Other income	129	2	671	332
Income tax (expense) benefit	(25)	115	(1,040)	20,814
Income (loss) from continuing operations and net income (loss)	$836	$(149)	$3,405	$(25,740)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Fuel production:				
Bbls of oil sold	99,950	91,091	268,768	286,405
Mcf of natural gas sold	2,285,016	2,574,036	6,793,866	7,916,515
Mcf equivalent sales	2,884,716	3,120,582	8,406,474	9,634,945

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Average price received: (a)				
Gas/Mcf (b)	$4.64	$4.50	$5.12	$4.44
Oil/Bbl	$80.87	$60.43	$81.70	$56.25
Depletion expense/Mcfe	$2.18	$2.07	$2.11	$2.08

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

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Following are summaries of LOE/Mcfe:

	Three Months Ended September 30, 2010			Three Months Ended September 30, 2009			
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total	
New Mexico	$1.15	$0.25	$1.40	$1.47	$0.31	$1.78	
Colorado	1.06	0.49	1.55	1.07	0.41	1.48	
Wyoming	1.50	—	1.50	1.29	—	1.29	
All other properties	0.75	—	0.75	0.83	(0.02)	0.81	(a)
All locations	$1.13	$0.16	$1.29	$1.24	$0.16	$1.40	(a)

	Nine Months Ended September 30, 2010			Nine Months Ended September 30, 2009			
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total	
New Mexico	$1.31	$0.31	$1.62	$1.29	$0.28	$1.57	
Colorado	0.66	0.64	1.30	1.02	0.41	1.43	
Wyoming	1.42	—	1.42	1.41	—	1.41	
All other properties	0.78	0.02	0.80	0.83	0.04	0.87	(a)
All locations	$1.16	$0.20	$1.36	$1.19	$0.17	$1.36	(a)

(a) During the first quarter of 2010, our Oil and Gas segment transferred midstream assets to a new subsidiary in our Energy Marketing segment. As a result, 2009 Gathering, Compression and Processing have been modified to reflect the removal of these assets for comparability purposes.

Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009. Income from continuing operations was $0.8 million for the three months ended September 30, 2010 compared to a Loss from continuing operations of $0.1 million for the same period in 2009 as a result of:

Revenue: Revenue increased $1.5 million primarily due to a 3% increase in the average hedged price of natural gas, a 34% increase in the average hedged price of oil, and a 10% increase in oil volumes primarily due to favorable volumes at new wells in our ongoing Bakken drilling program in North Dakota partially offset by an 11% decline in gas volumes. The volume decline was largely driven by natural production declines from producing properties, reflecting reduced capital deployment during 2010 and 2009.

Operating, general and administrative costs: Operating, general and administrative costs were comparable to the same period in prior year.

Depreciation, depletion and amortization: Depreciation, depletion and amortization increased $0.2 million primarily due to a higher depletion rate.

Interest expense: Interest expense increased $0.5 million primarily due to higher interest rates.

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

Income tax (expense) benefit: Income tax (expense) for the third quarter of 2010 was impacted by a $0.4 million re-measurement of a previously recorded uncertain tax position prompted by a settlement agreement with the IRS appeals Division. The tax position related to tax depreciation method changes. Income tax benefit for the third quarter 2009 was primarily affected by the favorable impact of percentage depletion.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009. Income from continuing operations was $3.4 million for the nine months ended September 30, 2010 compared to a Loss from continuing operations of $25.7 million in the same period in 2009 as a result of:

Revenue: Revenue increased $5.5 million due to a 15% increase in the average hedged price of natural gas and a 45% increase in the average hedged price of oil, partially offset by a 14% decline in gas volumes, a 6% decline in oil volumes and the impact of a $1.3 million charge for the reallocation of certain net revenues associated with reversionary ownership. The volume decline was largely driven by natural production declines from producing properties, reflecting reduced capital deployment during 2010 and 2009.

Operating, general and administrative costs: Operating, general and administrative costs for the first nine months of 2010 are comparable to the same period in the prior year.

Depreciation, depletion and amortization: Depreciation, depletion and amortization decreased $2.0 million primarily due to lower volumes partially offset by higher depletion rates.

Impairment of long-lived assets: A $27.8 million after-tax non-cash ceiling test impairment charge was taken during the first quarter of 2009. The write-down in the net carrying value of our natural gas and oil properties resulted from low March 31, 2009 quarter-end prices for the commodities. The write-down of gas and oil properties was based on period-end NYMEX prices of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas; and $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil.

Interest expense: Interest expense increased $0.2 million primarily due to higher interest rates.

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

Income tax (expense) benefit: The first nine months of 2010 included 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 first nine months of 2009 included a $3.8 million positive adjustment of a previously recorded tax position.

Coal Mining

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Revenue	$14,277	$15,187	$43,306	$43,082
Operating, general and administrative costs	10,750	10,665	30,041	31,761
Depreciation, depletion and amortization	3,342	3,502	9,553	11,075
Total operating expenses	14,092	14,167	39,594	42,836
Operating income	185	1,020	3,712	246
Interest income, net	1,086	330	2,191	913
Other income	510	2,226	1,593	2,931
Income tax expense	(108)	(1,320)	(1,403)	(1,515)

Income from continuing operations and net income	$1,673	$2,256	$6,093	$2,575

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Tons of coal sold	1,489	1,591	4,340	4,460
Cubic yards of overburden moved	4,482	4,187	11,805	10,822

Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009. Income from continuing operations was $1.7 million for the three months ended September 30, 2010 compared to Income from continuing operations of $2.3 million in the same period in 2009, as a result of:

Revenue: Revenue decreased $0.9 million primarily due to a 6% decrease in volumes sold primarily due to customer plant outages and lower demand for coal partially offset by sales to Wygen III, which commenced commercial operations in April 2010.

Operating, general and administrative costs: Operating, general and administrative costs were comparable to the prior year. Increases in mining, processing and overburden removal costs were partially offset by lower royalty costs and production taxes. Cubic yards of overburden moved increased 7%.

Depreciation, depletion and amortization: Depreciation, depletion and amortization expense decreased $0.2 million due to lower estimated future reclamation costs amortized over the life of the uncovered coal, partially offset by increased depreciation on equipment.

Interest income, net: Interest income, net increased $0.8 million due to increased lending to affiliates at higher interest rates.

Other income: Other income decreased $1.7 million due to the site lease rental income for the Wygen III power plant that was entered into in the third quarter of 2009 with revenues in the third quarter of 2009 including billings back to March 2008.

Income tax expense: Income tax expense decreased $1.2 million primarily due to lower pre-tax earnings for the three months ended September 30, 2010, along with the tax benefit generated by percentage depletion when compared to the three months ended September 30, 2009. The tax benefit generated by percentage of depletion had a significant impact on the effective tax rate in the current period.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009. Income from continuing operations was $6.1 million for the nine months ended September 30, 2010 compared to $2.6 million for the same period in 2009 as a result of:

Revenue: Revenue increased $0.2 million due to an increase of approximately 3% in average price received. The higher average price received reflects the impact of regulated sales prices determined in part by an approved return on our coal mine's cost-depreciated investment base. Tons of coal sold decreased 3% from the prior year as sales associated with the commencement of commercial operations of Wygen III were offset by customer plant outages and lower demand.

Operating, general and administrative costs: During 2010, we received approval from the State of 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 our mine site by re-assessing the handling of overburden.

Accordingly, overburden yards meeting backfill requirements were modified in the nine months ended September 30, 2010. The result was a reduction to overburden removal costs of approximately $2.0 million. Operating costs also decreased due to lower mining taxes. Cubic yards of overburden moved increased 9%.

Depreciation, depletion and amortization: Depreciation, depletion and amortization expense decreased approximately $1.5 million due to lower estimated future reclamation costs amortized over the life of our inventory of uncovered coal, partially offset by increased depreciation on equipment.

Interest income, net: Interest income, net increased $1.3 million due to increased lending to affiliates and higher interest rates.

Other income: Other income decreased $1.3 million primarily due to the site lease rental income for the Wygen III power plant that was entered into in the third quarter of 2009 with revenues in the third quarter of 2009 including billings back to March 2008.

Income tax expense: The effective tax rate for the nine months ended September 30, 2010 was lower than for the first nine months of 2009 primarily due to the tax benefit generated by percentage depletion.

Energy Marketing

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Revenue and gross margins —				
Realized gas marketing gross margin	$(3,897)	$262	$8,670	$22,617
Unrealized gas marketing gross margin	6,016	(5,252)	5,056	(12,230)
Realized oil marketing gross margin	2,952	1,525	5,526	9,633
Unrealized oil marketing gross margin	(1,268)	(1,794)	(504)	(10,721)
Realized coal marketing gross margin	241	—	(202)	—
Unrealized coal marketing gross margin	4,929	—	9,094	—
Total revenue and gross margins	8,973	(5,259)	27,640	9,299
Operating, general and administrative costs	6,349	482	17,807	9,652
Depreciation and amortization	128	122	387	384
Total operating expenses	6,477	604	18,194	10,036
Operating income	2,496	(5,863)	9,446	(737)
Interest expense, net	(380)	(668)	(1,942)	(731)
Other income	(1)	1	152	19
Income tax (expense) benefit	(745)	2,126	(2,766)	293
Income (loss) from continuing operations and net income (loss)	$1,370	$(4,404)	$4,890	$(1,156)

Following is a summary of average daily quantities marketed:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Natural gas physical sales — MMBtus	1,666,674	2,206,300	1,589,261	2,013,900
Crude oil physical sales — Bbls	19,410	13,300	17,947	12,100
Coal physical sales — Tons[(a)]	28,549	—	28,407	—

(a) The tons of coal marketed are for the period June 1, 2010 to September 30, 2010

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Gas and oil inventory held by Energy Marketing primarily consists of gas held in storage. Such gas is being held in inventory to capture the price differential between the time at which it was purchased and a subsequent sales date. Volumes held were as follows:

	As of September 30, 2010	As of December 31, 2009	As of September 30, 2009
Natural gas (MMBtu)	16,262,328	12,177,802	8,163,455
Crude oil (Bbl)	156,000	69,000	71,000

Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009. Income from continuing operations was $1.4 million for the three months ended September 30, 2010 compared to a Loss from continuing operations of $4.4 million in the same period in 2009 as a result of:

Revenue and gross margin: Revenue and gross margin increased $14.2 million primarily driven by increased unrealized marketing gains of $16.7 million. This increase was driven by timing of natural gas settlements and gains of $4.9 million from our portfolio of coal marketing contracts, which was acquired on June 1, 2010. The coal contracts acquired included a significant "long" coal position. An increase in the market price of coal produced unrealized gains for that position during the period. The unrealized marketing gains were partially offset by lower realized marketing gross margins of $2.5 million. A less favorable natural gas market contributed to this variance along with a decrease in natural gas volumes marketed. Crude oil volumes marketed increased 46% and natural gas volumes marketed decreased 24%.

Operating, general and administrative costs: Operating, general and administrative costs increased $5.9 million primarily due to higher non-cash provision for compensation expense related to increased margins and increased staff and benefit costs related to marketing new commodities and new geographic regions.

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

Interest expense, net: Interest expense, net decreased $0.3 million primarily due to decreased costs related to the committed Enserco Credit Facility partially offset by decreased interest income on lower cash balances.

Other income: Other income for the three months ended September 30, 2010 was comparable to the same period in the prior year.

Income tax (expense) benefit: The effective income tax rate for the three months ended September 30, 2010 was comparable to the same period in the prior year.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009. Income from continuing operations was $4.9 million for the nine months ended September 30, 2010 compared to a Loss from continuing operations of $1.2 million for the same period in 2009 as a result of:

Revenue and gross margin: Revenue and gross margin increased $18.3 million primarily driven by increased unrealized marketing gains of $36.6 million. This increase was driven primarily by the timing of natural gas settlements and gains of $9.1 million on our portfolio of coal marketing contracts, which was acquired on June 1, 2010. The coal contracts acquired included a significant "long" coal position. An increase in the market price of coal produced unrealized gains for that position during the period. The unrealized marketing gains were partially offset by lower realized marketing gross margins of $18.3 million, primarily in the natural gas portfolio. A less favorable natural gas market contributed to this variance along with a 21% decrease in natural gas volumes marketed.

Operating, general and administrative costs: Operating, general and administrative costs increased $8.2 million primarily due to increased non-cash provision for compensation expense related to increased margins, increased bank fees as a result of higher letter of credit costs due to a higher utilization level and commitment fees related to the committed credit facility, and increased staff and benefit costs related to trading new commodities and new geographic regions.

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

Interest expense, net: Interest expense, net increased $1.2 million primarily due to increased amortization of financing costs related to the committed Enserco Credit Facility and lower income received on affiliate loans and prepayments.

Other income: Other income for the nine months ended September 30, 2010 was comparable to the same period in the prior year.

Income tax (expense) benefit: The effective tax rate for the nine months ended September 30, 2010 was higher than for the nine months ended September 30, 2009 due to the impacts in 2009 of tax return adjustments related to 2008.

Power Generation

	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009
	(in thousands)			
Revenue	$7,855	$7,538	$22,602	$22,372
Cost of sales	1,616	1,258	5,358	3,873
Gross margin	6,239	6,280	17,244	18,499
Operating, general and administrative costs	2,108	1,671	6,931	5,398
Depreciation and amortization	1,048	961	3,374	2,812
Gain on sale of operating asset	—	—	—	(25,971)
Total operating expense (income)	3,156	2,632	10,305	(17,761)
Operating income	3,083	3,648	6,939	36,260
Interest expense, net	(2,194)	(3,152)	(6,177)	(9,191)
Other (expense) income	(266)	119	894	1,114
Income tax expense	(48)	(40)	(417)	(9,696)
Income from continuing operations and net income	$575	$575	$1,239	$18,487

The following table provides certain operating statistics for our plants within the Power Generation segment:

	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009
Contracted power plant fleet availability:				
Coal-fired plant	96.9%	98.7%	98.6%	95.6%
Natural gas-fired plants	100.0%	99.7%	100.0%	98.8%
Total availability	98.2%	99.1%	99.2%	96.9%

Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009. Income from continuing operations was $0.6 million for the three months ended September 30, 2010 compared to Income from continuing operations of $0.6 million in the same period in 2009 as a result of:

Revenue: Revenue for the three months ended September 30, 2010 was comparable to the same period in 2009.

Cost of Sales: Cost of sales for the first three months of 2010 was comparable to the same period in 2009.

Operating, general and administrative costs: Operating, general and administrative costs increased $0.4 million primarily due to increased intercompany costs associated with a shared services agreement.

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

Interest expense, net: Interest expense, net decreased $1.0 million primarily due to a decrease in debt from an intercompany debt restructuring partially offset by interest expense associated with the $120.0 million project financing at Black Hills Wyoming.

Other income: Other income decreased $0.4 million due to lower earnings from our partnership investments.

Income tax expense: The effective tax rate for the three months ended September 30, 2010 was comparable to the same period in the prior year.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009. Income from continuing operations was $1.2 million for the nine months ended September 30, 2010 compared to $18.5 million in the same period in 2009 as a result of:

Revenue: Revenue for the first nine months of 2010 was comparable to the same period in 2009.

Cost of Sales: Cost of sales increased $1.5 million primarily as a result of purchase of replacement power due to an extended outage at Wygen I.

Operating, general and administrative costs: Operating, general and administrative costs increased $1.5 million primarily due to maintenance costs for the major overhaul and an extended outage at Wygen I.

Depreciation and amortization: Depreciation and amortization increased $0.6 million primarily due to the write off of assets and commencement of depreciation of assets purchased from the major overhaul completed in the second quarter of 2010.

Gain on sale of operating asset: The gain on sale of operating asset of $26.0 million in the prior period represents the sale of a 23.5% ownership interest in the Wygen I generating facility to MEAN.

Interest expense, net: Interest expense, net decreased $3.0 million primarily due to a decrease in debt from an intercompany debt restructuring partially offset by the interest expense associated with the $120.0 million project financing at Black Hills Wyoming.

Other income: Other income is comparable to the same period in the prior year.

Income tax expense: The effective tax rate for the nine months ended September 30, 2010 was lower than for the nine months ended September 30, 2009 due to tax credits applied.

Corporate

Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009. Loss from continuing operations was $10.1 million for the three months ended September 30, 2010 compared to Loss from continuing operations of $9.1 million for the three months ended September 30, 2009 as a result of:

•Unrealized net, mark-to-market losses for the quarter ended September 30, 2010 of approximately $13.7 million on certain interest rate swaps compared to an $8.7 million unrealized mark-to-market loss on certain interest rate swaps in the prior period;

•A $0.8 million increase in net interest expense; and

•A $2.0 million decrease in income tax expense due to a re-measurement of a previously recorded uncertain tax position prompted by a settlement agreement with the IRS Appeals Division. The tax position relates to depreciation method changes.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009. Loss from continuing operations was $34.2 million compared to Income from continuing operations of $13.2 million as a result of:

•Unrealized net, mark-to-market losses for the nine months ended September 30, 2010 of approximately $41.7 million on certain interest rate swaps compared to a $37.8 million unrealized mark-to-market gain on certain interest rate swaps in the prior period; and

•A $1.7 million decrease in net interest expense; and

•A $2.0 million decrease in income tax expense due to a re-measurement of a previously recorded uncertain tax position prompted by a settlement agreement with the IRS Appeals Division. The tax position relates to depreciation method changes.

Discontinued Operations

Earnings from discontinued operations were $1.7 million and $2.4 million, net of tax, for the three and nine month periods ended September 30, 2009, respectively, relating to working capital and tax adjustments associated with the IPP Transaction.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2009 Annual Report on Form 10-K filed with the SEC. For more information on our critical accounting policies, see Part II, Item 7 of our 2009 Annual Report on Form 10-K.

Liquidity and Capital Resources

Cash Flow Activities

During the nine month period ended September 30, 2010, we generated sufficient cash flow to meet our operating needs, to pay dividends on our common stock, and to fund a portion of our property, plant and equipment additions. We plan to fund future property and investment additions, including the construction of utility and IPP generation to serve our Colorado Electric utility, from internally generated cash resources and external financings.

Cash flows from operations of $125.8 million for the nine month period ended September 30, 2010 represent a $145.2 million decrease compared to the same period in the prior year. The change in cash provided by operating activities was due to an $11.2 million decrease in income from continuing operations and changes in working capital as follows:

- A $131.3 million decrease in cash flows from working capital changes. This decrease primarily resulted from a $63.6 million decrease in materials, supplies and fuel, a $148.4 million decrease from changes in accounts receivable and other current assets and an $80.6 million increase from changes in accounts payable and other current liabilities. Changes in materials, supplies and fuel primarily relate to natural gas held in storage by Energy Marketing and the Gas Utilities segment which fluctuates based on seasonal trends and economic decisions reflecting current market conditions;

and adjusted for non-cash charges and other changes in operating items as follows:

- A $3.8 million decrease in depreciation, depletion and amortization expense;
- In 2009, an adjustment of $43.3 million for the non-cash ceiling test impairment charges to write down the net carrying value of our natural gas and crude oil properties due to low period-end commodity prices;
- A $30.3 million decrease in cash flows from the net change in derivative assets and liabilities primarily from commodity price fluctuations associated with normal operations of our Energy Marketing segment, our Oil and Gas segment and our Gas Utilities segment.
- An $8.9 million adjustment in 2010 for the effect of the gain on sale of operating assets, which relates to the partial sale of Wygen III to the City of Gillette and the sale of gas utility assets at Nebraska Gas compared to a $26.0 million adjustment in 2009 related to the gain on sale of a 23.5% ownership interest in Wygen I;
- A $79.4 million increase to adjust for the non-cash effect of unrealized mark-to-market losses on interest rate swaps;
- A $27.2 million increase in cash flows related to changes in deferred income taxes which is primarily due to certain property related temporary differences: and
- A $13.1 million decrease due to a cash contribution to the employee pension benefit plans.

During the nine months ended September 30, 2010, we had cash outflows from investing activities of $253.8 million, which were primarily due to the following:

- Cash outflows of $323.9 million for property, plant and equipment additions. These outflows include approximately $9.1 million related to the construction of our Wygen III power plant, which began commercial operations on April 1, 2010, approximately $82.6 million for construction of 180 MW of natural gas-fired electric generation at Colorado Electric, approximately $88.5 million for construction of 200 MW of natural gas-fired electric generation at Power Generation, approximately $24.3 million in oil and gas property maintenance capital and development drilling, and approximately $17.6 million for new transmission at the Electric Utilities;

- Cash inflows of $68.1 million of proceeds from the partial sale of Wygen III to the City of Gillette and the sale of gas utility assets at Nebraska Gas; and

- Cash outflows of $2.25 million for the acquisition of the coal marketing business at our Energy Marketing segment.

During the nine months ended September 30, 2010, we had net cash inflows from financing activities of $74.1 million primarily resulting from:

- A $19.5 million net outflows for reduction in net borrowings on the Revolving Credit Facility;

- A $42.3 million outflow for payments of cash dividends on common stock; and

- A $57.6 million outflow from long-term debt payments including $30.0 million for the Series AC bonds, $2.5 million for the Series Y bonds, $20.0 million for the Series Z bonds and payments of $5.0 million for the Black Hills Wyoming Project Financing debt.

- A $200.0 million inflow from the issuance of aggregate principal of senior unsecured notes due in 2020. The notes were priced at par and carry a fixed interest rate of 5.875%. We received proceeds of $198.7 million, net of underwriting fees.

Dividends

Dividends paid on our common stock totaled $42.3 million for the nine months ended September 30, 2010, or $1.08 per share. On October 28, 2010, our Board of Directors declared an additional quarterly dividend of $0.36 per share payable December 1, 2010, which is equivalent to an annual dividend rate of $1.44 per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects.

Financing Transactions and Short-Term Liquidity

Our principal sources of short-term liquidity are our Revolving Credit Facility and cash provided by operations. In addition to availability under our Revolving Credit Facility described below, as of September 30, 2010, we had approximately $59.0 million of cash unrestricted for operations.

$200 Million Debt Offering

On July 16, 2010, pursuant to a public offering, we issued a $200 million aggregate principal of senior unsecured notes due in 2020. The notes were priced at par and carry a fixed interest rate of 5.875%. 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 reduce issued letters of credit.

Revolving Credit Facility

On April 15, 2010, we terminated our $525.0 million Corporate Credit Facility and entered into a new $500.0 million Revolving Credit Facility expiring April 14, 2013. The new Revolving Credit Facility can be used for the issuance of letters of credit, to fund working capital needs and for general corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 1.75%, 2.75% and 2.75%, respectively. The facility contains a commitment fee to be charged on the unused amount of the Facility. Based upon current credit ratings, the fee is 0.5%. The facility contains an accordion feature which allows us, with the consent of the administrative agent, to increase the capacity of the facility to $600.0 million. Deferred financing costs of $4.7 million were capitalized and are being amortized over the three-year term of the facility.

At September 30, 2010, we had borrowings of $145.0 million and letters of credit outstanding of $15.5 million on our Revolving Credit Facility. Available capacity remaining on our Revolving Credit Facility was approximately $339.5 million at September 30, 2010.

Our consolidated net worth was $1,080.4 million at September 30, 2010, which was approximately $237.9 million in excess of the net worth we were required to maintain under the credit facility. At September 30, 2010, our long-term debt ratio was 52.4%, our total debt leverage ratio (long-term debt and short-term debt) was 55.3%, and our recourse leverage ratio was approximately 56.1%.

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and 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.

Our ratios are calculated as required under the Revolving Credit Facility. 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 (except letters of credit issued by our marketing subsidiary up to $250 million) and guarantees issued over our total capital which includes the balance in the numerator plus our net worth.

In addition to covenant violations, an event of default under the credit facility may be triggered by other events, such as a failure to make payments when due or a failure to make payments when due in respect of, or a failure to perform obligations relating to, other debt obligations of $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.

Enserco Credit Facility

In May 2010, Enserco entered into an agreement for a two-year, $250.0 million committed credit facility. The facility includes a $100 million accordion feature which allows us, with the consent of the administrative agent, to increase commitments under the facility. Societe Generale and BNP Paribas are co-lead arranger banks. The Bank of Tokyo

Mitsubishi UFJ, Raiffeisen-Boerenleenbank BA (Rabobank), Credit Agricole, RZB Finance and U.S. Bank are participating banks. This Facility replaces the $300 million credit facility which expired on May 7, 2010. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. Margins for base rate borrowings are 1.75% and for Eurodollar borrowings are 2.50%.

At September 30, 2010, $131.5 million of letters of credit were issued under this facility and there were no cash borrowings outstanding.

As a result of contractual positions acquired with the June 1, 2010 coal marketing business acquisition (see Note 20 of the Notes to the Condensed Consolidated Financial Statements), Enserco was temporarily not in compliance on one of the non-financial covenants to the Enserco Credit Facility. The Enserco Credit Facility limited the net fixed price volume of coal to 1.0 million tons. As of June 30, 2010, Enserco was above that limit. In July 2010, the participating banks waived this covenant violation and increased the permitted net fixed price volume of coal allowed to 2.25 million tons for July 2010 and 2.0 million tons thereafter. Enserco was in compliance with this covenant as of September 30, 2010.

In September 2010, the Enserco Credit Facility was amended to allow for trading of electric power, renewable energy credits and emissions credits.

Black Hills Power

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

In March 2010, Black Hills Power completed a call 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%.

In June 2010, Black Hills Power completed a call 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%.

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 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 September 30, 2010, the restricted net assets at our Electric and Gas Utilities were approximately $245.0 million.

Our 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 September 30, 2010 were $104.6 million compared to $205.8 million at December 31, 2009. Improved covenants under the new Enserco Credit Facility allowed for a reduction in capital investments in Enserco of more than $40 million.

As a covenant of the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted assets of $100.0 million. Black Hills Non-regulated Holdings is the parent of Black Hills Electric Generation which is the parent of Black Hills Wyoming.

Future Financing Plans

We have an effective 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 agreements and restrictions imposed by federal and state regulatory authorities.

We have substantial capital expenditures remaining in 2010 and in 2011, which are primarily due to the construction of additional utility and IPP generation to serve our Colorado Electric Utility. Our capital requirements are expected to be financed through a combination of operating cash flows, borrowings on our Revolving Credit Facility and long-term financings. We may complete an additional long-term senior unsecured debt financing at the holding company level in 2011. We intend to maintain a consolidated debt-to-capitalization level in the range of 50% to 55%; however, during the construction period of our new generation facilities in Colorado, we may exceed this level on a temporary basis. We will likely complete a portion of the permanent financing through the issuance of common stock in order to maintain our target debt-to-capitalization level. We do not anticipate any difficulty accessing debt or equity markets.

Hedges and Derivatives

Interest Rate Swaps

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations.

We have interest rate swaps with a notional amount of $250.0 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on these swaps are recorded within the income statement. For the three and nine months ended September 30, 2010, respectively, we recorded a $13.7 million and $41.7 million pre-tax unrealized mark-to-market non-cash loss on the swaps. The mark-to-market value on these swaps was a liability of $80.5 million at September 30, 2010. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A one basis point move in the interest rate curves over the term of the swaps would have a pre-tax impact of approximately $0.4 million. These swaps hedge interest rate exposure for periods to 2018 and 2028 and have amended mandatory early termination dates ranging from December 15, 2010 to December 29, 2010. We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly as they relate to our planned capital requirements to build gas-fired power generation facilities to serve our Colorado Electric customers, and because of our upcoming holding company debt maturities, which are $225 million and $250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at their fair value prior to their mandatory early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair value on the termination dates.

In addition, we have $150.0 million notional amount floating-to-fixed interest rate swaps, having a maximum remaining term of 6.25 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 Condensed Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $28.4 million at September 30, 2010.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2009 Annual Report on Form 10-K filed with the SEC.

Energy Marketing Commodities

Our energy marketing segment uses derivative instruments, including options, swaps, futures, forwards and other contractual commitments for both non-trading (hedging) and trading purposes. These activities can have liquidity impacts which the company monitors and manages in accordance with its Risk Management Policies and Procedures. The primary sources of liquidity for our energy marketing segment are: cash from operations, the stand-alone Enserco Credit Facility and advances of cash from the parent company.

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

The addition of the coal, environmental, and power marketing businesses is not expected to result in a significant increase to the liquidity requirement of the marketing business in the near term.

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 September 30, 2010, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

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

In addition, as of September 30, 2010, Black Hills Power's first mortgage bonds were rated as follows:

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

* In October 2010, Fitch published an updated credit review on Black Hills Corp., leaving unchanged our senior unsecured credit rating of BBB and leaving unchanged a stable ratings outlook.
** In July 2010, Moody's and S&P published updated credit reviews on Black Hills Corp., leaving unchanged our senior unsecured credit ratings of Baa3 and BBB-, respectively, and leaving unchanged stable ratings outlooks.

Capital Requirements

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

	Expenditures for the Nine Months Ended September 30, 2010	Total 2010 Planned Expenditures
Utilities:		
Electric Utilities (1) (2) (3)	$161,700	$264,590
Gas Utilities	32,956	51,080
Non-regulated Energy:		
Oil and Gas(4)	27,405	45,300
Power Generation (5)	92,827	127,545
Coal Mining	12,872	18,460
Energy Marketing (6)	314	4,920
Corporate	8,918	—
	$336,992	$511,895

(1) Includes approximately $9.2 million associated with final construction costs of the Wygen III coal-fired plant that went into service on April 1, 2010. We own 52% of the Wygen III plant.

(2) Electric Utilities planned capital expenditures including approximately $34.3 million for transmission projects in 2010 (excluding transmission related to the 180 MW power plant at Colorado Electric) of which $17.6 million was spent in the first nine months of 2010.

(3) The 2010 total planned expenditures include capital requirements associated with our plans to build a 180 MW gas-fired power generation facility to serve our Colorado Electric customers. We expect to spend capital on this project, including transmission, of $138.7 million during 2010. We spent $82.6 million during the first nine months of 2010, and expect $59.7 million to be spent in the remainder of 2010. The total construction cost of the facility is expected to be approximately $250 million to $260 million and construction is expected to be completed by the end of 2011. The planned expenditures indicated for 2010 include optimizing accelerated depreciation for federal income tax purposes in the form of bonus depreciation, which was retroactively reinstated by Congress and signed into law by the President on September 27, 2010.

(4) Development capital for our oil and gas properties is expected to approximate the level of the cash flows produced by those properties. Continued low commodity prices will impact our planned development capital expenditures.

(5) Our Power Generation segment was awarded the bid to provide 200 MW of generation capacity for a twenty year period to Colorado Electric. We expect to spend approximately $125.0 million on the facility in 2010, including $88.5 million spent during the first nine months of 2010. The total construction cost of the new facility is expected to be approximately $240 million to $265 million, and construction is expected to be completed by the end of 2011.

The planned expenditures indicated for 2010 represent a slight increase over the previous forecasted amount. Such increase is attributable to optimizing accelerated depreciation for federal income tax purposes in the form of bonus depreciation, which was retroactively reinstated by Congress and signed into law by the President on September 27, 2010.

(6) Includes $2.25 million for the acquisition of the coal marketing business. During 2010, we anticipate that an additional $0.8 million will be invested in related capital purchases.

We continually evaluate all of our forecasted capital expenditures, and if determined prudent, we may defer some of these expenditures for a period of time. Future projects are dependent upon the availability of attractive economic opportunities, and as a result, actual expenditures may vary significantly from forecasted estimates.

Contractual Obligations

Unconditional purchase obligations for firm transportation and storage fees for our Energy Marketing segment decreased $3.6 million from $97.7 million at December 31, 2009 to $94.1 million at September 30, 2010. Approximately $53.6 million of the firm transportation and storage fee obligations relate to the 2010-2012 period with the remaining occurring thereafter.

Construction of a 180 MW power generation facility by our Colorado Electric utility and 200 MW power generation facility by our Power Generation segment is progressing. Cost of construction is expected to be approximately $250 million to $260 million for Colorado Electric and $240 million to $265 million for the Power Generation segment. Construction is expected to be completed at both facilities by December 31, 2011. We are in the process of procuring or have procured contracts for the turbines, building construction and labor. As of September 30, 2010, committed contracts for equipment purchases and for construction were 100% and 70% complete, respectively, for the Colorado Electric utility and 94% and 61% complete, respectively, for the Power Generation segment.

Guarantees

Except as noted below, there have been no new guarantees provided from those previously disclosed in Note 20 of our Notes to the Consolidated Financial Statements in our 2009 Annual Report on Form 10-K.

We issued a guarantee for $6.0 million for a payment obligation arising from a contract to construct and purchase a new office building by Black Hills Utility Holdings. The office building is a 36,000 square foot office building located in Papillion, Nebraska. The guarantee will expire upon purchase of the building which is expected to be completed in 2011.

In May 2010, Black Hills Electric Generation issued a guarantee to the City of Pueblo, Colorado for the lesser of (a) the guaranteed obligations under the Annexation Agreement or (b) $10.0 million for the obligations of Colorado IPP relating to the construction of the 200 MW generation facility. The payment of $2.9 million was made to the City of Pueblo in September 2010 and the guarantee terminated as of September 30, 2010.

We issued a guarantee to Colorado Interstate Gas Company for $9.3 million for payment obligations of Black Hills Utility Holdings, Inc. related to natural gas transportation storage and services agreements. The guarantee expires July 31, 2011.

New Accounting Pronouncements

Other than the new pronouncements reported in our 2009 Annual Report on Form 10-K filed with the SEC and those discussed in Note 2 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial statements.

FORWARD-LOOKING INFORMATION

This report contains forward-looking information. All statements, other than statements of historical fact, included in this report that address activities, events, or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. Forward-looking information involves risks and uncertainties, and certain important factors can cause actual results to differ materially from those anticipated. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. The factors which may cause our results to vary significantly from our forward-looking statements include the risk factors described in Item 1A. of our 2009 Annual Report on Form 10-K, Part II, Item 1A of this quarterly report on Form 10-Q, and other reports that we file with the SEC from time to time, and the following:

- We are evaluating financing options including senior notes, first mortgage bonds, term loans, project financing and equity issuance. Some important factors that could cause actual results to differ materially from those anticipated include:

- Our ability to access the bank loan and debt and equity capital markets depends on market conditions beyond our control. If the capital markets deteriorate, we may not be able to permanently refinance some short-term debt and fund our power generation projects on reasonable terms, if at all.

- Our ability to raise capital in the debt capital markets depends upon our financial condition and credit ratings, among other things. If our financial condition deteriorates unexpectedly, or our credit ratings are lowered, we may not be able to refinance some short-term debt and fund our power generation projects on reasonable terms, if at all.

- We anticipate that our existing credit capacity and available cash will be sufficient to fund our working capital needs and our maintenance capital requirements. Some important factors that could cause actual results to differ materially from those anticipated include:

- Our access to revolving credit capacity depends on maintaining compliance with loan covenants. If we violate these covenants, we may lose revolving credit capacity and not have sufficient cash available for our peak winter needs and other working capital requirements, and our forecasted capital expenditure requirements.

- Counterparties may default on their obligations to supply commodities, return collateral to us, or otherwise meet their obligations under commercial contracts, including those designed to hedge against movements in commodity prices.

- We expect to fund a portion of our capital requirements for the planned regulated and non-regulated generation additions to supply our Colorado Electric subsidiary through a combination of long-term debt and issuance of equity.

- We expect contributions to our defined benefit pension plans to be approximately $0.0 million and $5.1 million for the remainder of 2010 and for 2011, respectively. Some important factors that could cause actual contributions to differ materially from anticipated amounts include:

- The actual value of the plans' invested assets.

- The discount rate used in determining the funding requirement.
- The outcome of pending labor negotiations relating to benefit participation of our collective bargaining agreements.
- We expect the goodwill related to our utility assets to fairly reflect the long-term value of stable, long-lived utility assets. Some important factors that could cause us to revisit the fair value of this goodwill include:
- A significant and sustained deterioration of the market value of our common stock.

- Negative regulatory orders, condemnation proceedings or other events that materially impact our Utilities' ability to generate sufficient stable cash flow over an extended period of time.

- We expect to make approximately $511.9 million of capital expenditures in 2010. Some important factors that could cause actual expenditures to differ materially from those anticipated include:

- The timing of planned generation, transmission or distribution projects for our Utilities is influenced by state and federal regulatory authorities and third parties. The occurrence of events that impact (favorably or unfavorably) our ability to make planned or unplanned capital expenditures could cause our forecasted capital expenditures to change.

- Forecasted capital expenditures associated with our Oil and Gas segment are driven, in part, by current market prices. Changes in crude oil and natural gas prices may cause us to change our planned capital expenditures related to our oil and gas operations.

- Our ability to complete the planning, permitting, construction, start-up and operation of power generation facilities in a cost-efficient and timely manner.

- The timing, volatility, and extent of changes in energy and commodity prices, supply or volume, the cost and availability of transportation of commodities, changes in interest or foreign exchange rates, and the demand for our services, any of which can affect our earnings, our financial liquidity and the underlying value of our assets including the possibility that we may be required to take future impairment charges under the SEC's full cost ceiling test for natural gas and oil reserves.

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

- The effect of Dodd-Frank and the regulations to be adopted there under on our use of oil and natural gas derivative instruments in connection with our energy marketing activities and to hedge our expected production of oil and natural gas and on our use of interest rate derivative instruments.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

We produce, purchase and distribute power in four states and purchase and distribute natural gas in five states. All of our gas distribution utilities have PGA provisions that allow them to pass the prudently-incurred cost of gas through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to true-up billed amounts to match the actual natural gas cost we incurred. These adjustments are subject to periodic prudence reviews by the state utility commissions. We have a mechanism in South Dakota, Colorado, Wyoming and Montana for our electric utilities that serves a purpose similar to the PGAs for our 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 derivative contracts are summarized below (in thousands):

	September 30, 2010	December 31, 2009	September 30, 2009
Net derivative (liabilities) assets	$(16,078)	$(1,511)	3,210
Cash collateral	20,519	3,789	1,840
	$4,441	$2,278	5,050

Non Regulated Trading Activities

The following table provides a reconciliation of Energy Marketing activity in our natural gas, crude oil and coal marketing portfolio that has been recorded at fair value including market value adjustments on inventory positions that have been designated as part of a fair value hedge during the nine months ended September 30, 2010 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2009	$19,521	(a)
Net cash settled during the period on positions that existed at December 31, 2009	(7,876)	
Unrealized gain (loss) on new positions entered during the period and still existing at September 30, 2010	28,560	
Realized (gain) loss on positions that existed at December 31, 2009 and were settled during the period	(3,663)	
Change in cash collateral	(10,093)	
Unrealized gain (loss) on positions that existed at December 31, 2009 and still exist at September 30, 2010	(796)	
Total fair value of energy marketing positions at September 30, 2010	$25,653	(a)

(a) The fair value of energy marketing positions consists of derivative assets/liabilities held at fair value in accordance with accounting standards for fair value measurements and market value adjustments to natural gas inventory that has been designated as a hedged item as part of a fair value hedge in accordance with accounting standards for derivatives and hedges, as follows (in thousands):

	September 30, 2010	June 30, 2010	March 31, 2010	December 31, 2009
Net derivative assets	$51,734	31,720	$25,634	$17,084
Cash collateral	(7,365)	—	171	2,728
Market adjustment recorded in material, supplies and fuel	(18,716)	(8,469)	(11,039)	(291)
Total fair value of energy marketing positions marked-to-market	$25,653	$23,251	$14,766	$19,521

To value the assets and liabilities for our outstanding derivative contracts, we use the fair value methodology outlined in accounting standards for fair value measurements and disclosures. See Note 3 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K and Note 13 and Note 14 of the accompanying Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

Source of Fair Value of Energy Marketing Positions	Maturities Less than 1 year	1 - 2 years	Total Fair Value
Cash collateral	$(6,827)	$(538)	$(7,365)
Level 1	—	—	—
Level 2	43,432	5,896	49,328
Level 3	1,273	1,133	2,406
Market value adjustment for inventory (see footnote (a) above)	(18,716)	—	(18,716)
Total fair value of our energy marketing positions	$19,162	$6,491	$25,653

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

The following table presents a reconciliation of our September 30, 2010 energy marketing positions recorded at fair value under GAAP to a non-GAAP measure of the fair value of our energy marketing forward book wherein all forward trading positions are marked-to-market (in thousands):

Fair value of our energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$25,653
Market value adjustments for inventory, storage and transportation positions that are part of our forward trading book, but that are not marked-to-market under GAAP	(30,777)
Fair value of all forward positions (non-GAAP)	(5,124)
Cash collateral included in GAAP marked-to-market fair value	7,365
Fair value of all forward positions excluding cash collateral (non-GAAP) *	$2,241

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

Except as discussed above, there have been no material changes in market risk from those reported in our 2009 Annual Report on Form 10-K filed with the SEC. For more information on market risk, see Part II, Items 7 and 7A. in our 2009 Annual Report on Form 10-K, and Note 13 of the Notes to our Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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Activities Other Than Trading

We have entered into agreements to hedge a portion of our estimated 2010, 2011 and 2012 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place are as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)	Price
AECO	10/24/2008	Swap	10/10 - 12/10	1,000	$7.05
San Juan El Paso	12/19/2008	Swap	10/10 - 12/10	5,000	$5.89
CIG	1/26/2009	Swap	10/10 - 12/10	2,000	$4.68
CIG	1/26/2009	Swap	01/11 - 03/11	2,000	$6.00
NWR	1/26/2009	Swap	01/11 - 03/11	2,000	$6.05
San Juan El Paso	1/26/2009	Swap	01/11 - 03/11	5,000	$6.38
San Juan El Paso	2/13/2009	Swap	01/11 - 03/11	2,500	$6.16
San Juan El Paso	2/13/2009	Swap	10/10 - 12/10	3,000	$5.35
NWR	2/13/2009	Swap	04/10 - 12/10	1,000	$4.20
AECO	3/4/2009	Swap	01/11 - 03/11	1,000	$5.95
NWR	3/4/2009	Swap	10/10 - 12/10	1,000	$4.55
San Juan El Paso	6/2/2009	Swap	04/11 - 06/11	5,000	$5.99
AECO	6/2/2009	Swap	04/11 - 06/11	800	$5.89
NWR	6/2/2009	Swap	04/11 - 06/11	1,500	$5.54
San Juan El Paso	6/25/2009	Swap	04/11 - 06/11	2,500	$5.55
CIG	6/25/2009	Swap	04/11 - 06/11	1,750	$5.33
CIG	9/2/2009	Swap	07/11 - 09/11	500	$5.32
NWR	9/2/2009	Swap	07/11 - 09/11	500	$5.32
San Juan El Paso	9/2/2009	Swap	07/11 - 09/11	2,500	$5.54
CIG	9/25/2009	Swap	07/11 - 09/11	500	$5.59
NWR	9/25/2009	Swap	07/11 - 09/11	1,000	$5.59
AECO	9/25/2009	Swap	07/11 - 09/11	500	$5.76
San Juan El Paso	9/25/2009	Swap	07/11 - 09/11	5,000	$5.91
San Juan El Paso	10/9/2009	Swap	10/10 - 12/10	1,000	$5.90
San Juan El Paso	10/23/2009	Swap	10/11 - 12/11	2,500	$6.23
NWR	10/23/2009	Swap	10/11 - 12/11	1,500	$6.12
San Juan El Paso	10/23/2009	Swap	01/11 - 03/11	1,000	$6.59
AECO	12/11/2009	Swap	10/11 - 12/11	500	$6.27
CIG	12/11/2009	Swap	10/11 - 12/11	1,500	$6.03
San Juan El Paso	12/11/2009	Swap	10/11 - 12/11	5,000	$6.15
San Juan El Paso	1/8/2010	Swap	1/12 - 3/12	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	1/12 - 3/12	5,000	$6.44
San Juan El Paso	3/19/2010	Swap	7/11 - 9/11	500	$5.19
San Juan El Paso	3/19/2010	Swap	4/12 - 6/12	7,000	$5.27
CIG	3/19/2010	Swap	4/12 - 6/12	1,500	$5.17
NWR	3/19/2010	Swap	4/12 - 6/12	1,500	$5.20
AECO	3/19/2010	Swap	4/12 - 6/12	250	$5.15
San Juan El Paso	6/28/2010	Swap	7/12 - 9/12	3,500	$5.19

NWR	6/28/2010	Swap	7/12 - 9/12	1,500	$5.01
CIG	6/28/2010	Swap	7/12 - 9/12	1,500	$4.98

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	12/5/2008	Swap	10/10 - 12/10	5,000	$65.20
NYMEX	1/26/2009	Swap	10/10 - 12/10	5,000	$60.15
NYMEX	1/26/2009	Swap	01/11 - 03/11	5,000	$60.90
NYMEX	2/13/2009	Swap	01/11 - 03/11	5,000	$60.05
NYMEX	3/4/2009	Swap	10/10 - 12/10	5,000	$55.80
NYMEX	3/4/2009	Swap	01/11 - 03/11	5,000	$57.00
NYMEX	4/8/2009	Swap	04/11 - 06/11	5,000	$68.80
NYMEX	4/23/2009	Swap	04/11 - 06/11	5,000	$65.10
NYMEX	6/2/2009	Swap	10/10 - 12/10	5,000	$74.30
NYMEX	6/2/2009	Swap	01/11 - 03/11	5,000	$75.05
NYMEX	6/2/2009	Swap	04/11 - 06/11	5,000	$75.86
NYMEX	6/4/2009	Put	04/11 - 06/11	5,000	$67.00
NYMEX	9/2/2009	Swap	07/11 - 09/11	5,000	$75.10
NYMEX	9/2/2009	Put	07/11 - 09/11	5,000	$63.00
NYMEX	9/29/2009	Swap	07/11 - 09/11	5,000	$74.00
NYMEX	10/6/2009	Put	07/11 - 09/11	5,000	$65.00
NYMEX	10/9/2009	Swap	10/11 - 12/11	5,000	$79.35
NYMEX	10/23/2009	Put	10/11 - 12/11	5,000	$75.00
NYMEX	11/19/2009	Swap	04/11 - 06/11	1,000	$85.35
NYMEX	11/19/2009	Swap	07/11 - 09/11	1,500	$85.95
NYMEX	11/19/2009	Swap	10/11 - 12/11	5,000	$87.50
NYMEX	1/8/2010	Swap	10/10 - 12/10	5,000	$86.88
NYMEX	1/8/2010	Put	10/11 - 12/11	6,000	$75.00
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

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
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	6/28/2010	Swap	07/12 - 09/12	5,000	$83.80
NYMEX	8/17/2010	Swap	04/12 - 06/12	3,000	$82.60
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

ITEM 4. 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) as of September 30, 2010. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

There have been no changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2010 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting. The Company has been operating with two separate financial systems since the acquisition of the Aquila properties in July 2008. Since the acquisition, the Company has been working towards converting to one upgraded system. Effective August 1, 2010, the Company implemented the new financial and human resource system. Although many financial processes were changed, the underlying internal controls did not materially change. The new financial and human resource system was implemented as part of a corporate unification project and was not undertaken in response to any actual or perceived significant deficiencies in the Company's internal control over financial reporting. The new system streamlines processes by consolidating two financial systems into one, standardizes accounting systems, is intended to improve management reporting and will consolidate accounting functions for the Company and its subsidiaries.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 2009 Annual Report on Form 10-K and Note 16 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 16 is incorporated by reference into this item.

ITEM 1A. Risk Factors

Except to the extent updated or described below, there are no material changes to the Risk Factors previously disclosed in Item 1A of Part I in our Annual Report on Form 10-K for the year ended December 31, 2009.

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

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, the Dodd-Frank was passed by Congress and signed into law. Dodd-Frank contains significant derivatives regulations, including a requirement that certain transactions be cleared on exchanges and a requirement to post cash collateral (commonly referred to as "margin") for such transactions. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users, and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. Dodd-Frank requires the CFTC to promulgate rules to define these terms, however we do not yet know the rules that the CFTC will actually promulgate, nor if the definitions may apply to us.

We use crude oil and natural gas derivative instruments in conjunction with our Energy Marketing activities and to hedge a portion of our expected oil and gas production. We also use interest rate derivative instruments to minimize the impact of interest rate fluctuations associated with anticipated debt issuances. 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.

Federal and state laws concerning climate change 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, Colorado and Idaho. We recently completed another fossil-fuel generating plant in Wyoming and are constructing others in Colorado. Recent developments under federal and state laws and regulation governing air emissions from fossil-fuel generating plants will likely result in more stringent emission limitations, which could have a material impact on our costs or operations.

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

On June 23, 2010, the EPA published in the Federal Register the Greenhouse Gas Tailoring Rule, implementing regulation of greenhouse gases for permitting purposes. This rule will impact Black Hills in the event of a major modification at an existing facility or in the event of construction of a new major source. Existing permitted facilities will see monitoring and reporting requirements incorporated into their operating permits upon renewal. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could result in more stringent emissions control practices and technologies.

On April 29, 2010, the EPA published in the Federal Register the proposed Industrial and Commercial Boiler Hazardous Air Pollutant ("IB MACT") regulations, proposing hazardous air pollutant related emission limits and monitoring requirements. The final rule has a court ordered deadline of January 16, 2011 and as proposed, will require significant impact at our Neil Simpson 1, Osage, Ben French and WN Clark facilities. The regulation currently has a three year compliance window and will require engineering evaluations to determine economic viability of continued operations of these units. In our current opinion, the proposed regulations will lead to retirement of these units within three years of the effective date of the final rule.

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 and at this time we cannot determine an accurate impact on our operations. Our largest ash disposal area is the Wyodak Mine where ash is permitted for use as backfill. The proposed regulations do not address mine backfill but we fully expect that the U.S. Office of Surface Mining will be collaborating with EPA to address mine backfill in the near future.

In the 2010 legislative session, the State of Colorado passed House Bill 10-1365, a coordinated utility plan to reduce air emissions from coal fired power plants and promoting the use of natural gas and other low emitting resources. This act has a significant impact on our W.N. Clark facility and on October 29, 2010, Black Hills Energy - Colorado Electric filed testimony with the Colorado Public Utilities Commission (PUC) that included a proposal recommending retirement of the W.N. Clark facility. An initial filing with the Colorado PUC was made on August 13, 2010 as required by House Bill 1365 that indicated the utility would be analyzing two options to comply with the legislation; conversion to 100 percent woody biomass fuel or retirement and replacement with new utility-owned gas-fired generation. Subsequent engineering studies have determined that conversion to woody biomass is not an economical option for our customers. Therefore the October 29, 2010 filing before the Colorado PUC requests approval of our plan to comply with House Bill 10-1365 by retiring the Clark facility within 3 years of promulgation of EPA's proposed Industrial and Commercial Boiler Hazardous Air Pollutant Regulation, or in the absence of the regulation, to retire the unit by the end of 2017. Hearings before the Colorado PUC are currently scheduled for November 19 and 22, 2010.

EPA is expected to propose the Electric Utility MACT regulation for control of hazardous air pollutants, in the first quarter of 2011. Certain requirements of that regulation could have significant impacts on Neil Simpson 2, Wygen I, II and III. Also late in 2011 EPA is scheduled to issue updated regulations for wastewater discharges from electric generating units, which could have a significant impact on all of our generating fleet.

In addition, various climate change bills are under consideration in Congress. Due to uncertainty as to the final outcome of federal climate change legislation, or regulatory changes under the Clean Air Act, we cannot definitively estimate the effect of GHG regulation on our results of operations, cash flows or financial position. The impact of GHG legislation or regulation upon our company will depend upon many factors, including but not limited to the timing of implementation, the GHG sources that are regulated, the overall GHG emissions cap level, and the availability of technologies to control or reduce GHG emissions. If a "cap and trade" structure is implemented, the impact will also be affected by the degree to which offsets are allowed, the allocation of emission allowances to specific sources, and the effect of carbon regulation on natural gas and coal prices.

New or more stringent regulations, included GHG emissions limitations or other energy efficiency requirements, such as the EPA's recently published Greenhouse Gas Tailoring Rule, which will require additional monitoring and reporting requirements for existing and new facilities, and a recently passed Colorado State bill requiring use of low emission control equipment, the acceleration of capital expenditures, the purchase of additional emission allowances or offsets, the acquisition or development of additional energy supply from renewable resources, and the closure of certain generating facilities. To the extent our regulated fossil-fuel generating plants are included in rate base, we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the power generated by our non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.

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

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 previously deferred approximately $185 million in taxes associated with the IPP Transaction and the Aquila Transaction, and in the third quarter of 2010, we reached an agreement with the Appeals Division of the IRS that resulted in a decrease of 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.

Increased risks of regulatory penalties could negatively impact our business.
The Energy Policy Act of 2005 increased the Federal Energy Regulatory Commission's (“FERC”) civil penalty authority for violation of FERC statutes, rules and orders. FERC can now impose penalties of $1.0 million per violation, per day, and other regulatory agencies that impose compliance requirements relative to our business also have civil penalty authority. In addition, FERC has delegated certain aspects of authority for enforcement of electric system reliability standards to the North American Electric Reliability Corporation, with similar penalty authority for violations. Many rules that were historically subject to voluntary compliance are now mandatory and subject to potential civil penalties for violations. If a serious violation did occur, and penalties were imposed by FERC or another federal agency, this action could have a material adverse effect on our operations or our financial results.
Our financial performance depends on the successful operation of our facilities.
Operating electric generating facilities and electric and natural gas distribution systems involves risks, including:

•Operational limitations imposed by environmental and other regulatory requirements.

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

•Breakdown or failure of equipment or processes.

•Inability to recruit and retain skilled technical labor.

•Labor relations. Approximately 35% of our employees are represented by a total of six collective bargaining agreements. We are currently in contract renewal negotiations on two of these agreements. Three separate arbitration proceedings have been initiated by the respective union locals concerning changes we made to our pension plans.

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

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans for Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2010 - July 31, 2010	—	$—	—	—
August 1, 2010 - August 31, 2010	3,837	$31.30	—	—
September 1, 2010 - September 30, 2010	—	$—	—	—
Total	3,837	$31.30	—	—

(1) Shares were acquired from certain officers and key employees under the share withholding provisions of the Omnibus Incentive Plan for the payment of taxes associated with the vesting of shares of Restricted Stock.

ITEM 5. Other Information

Mine Safety and Health Administration Safety Data

Safety is a core value at Black Hills Corporation and at each of its subsidiary operations. We have in place a comprehensive safety program that includes extensive health & safety training for all employees, site inspections, emergency response preparedness, crisis communications training, incident investigation, regulatory compliance training and process auditing, as well as an open dialogue between all levels of employees. The goals of our processes are to eliminate exposure to hazards in the workplace, ensure that we comply with all mine safety regulations, and support regulatory and industry efforts to improve the health and safety of our employees along with the industry as a whole.

Under the recently enacted Dodd-Frank Act, each operator of a coal or other mine is required to include certain mine safety results in its periodic reports filed with the SEC. Our mining operations, consisting of our Wyodak Coal Mine, is subject to regulation by the federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Act"). Below we present the following items regarding certain mining safety and health matters, for the three-month period ended September 30, 2010. In evaluating this information, consideration should be given to factors such as: (i) the number of citations and orders will vary depending on the size of the coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process, are often reduced in severity and amount, and are sometimes dismissed. The information presented includes:

- Total number of violations of mandatory health and safety standards that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard under section 104 of the Mine Act for which we have received a citation from MSHA;
- Total number of orders issued under section 104(b) of the Mine Act;
- Total number of citations and orders for unwarrantable failure of the mine operator to comply with mandatory health and safety standards under section 104(d) of the Mine Act;
- Total number of imminent danger orders issued under section 107(a) of the Mine Act; and
- Total dollar value of proposed assessments from MSHA under the Mine Act.

During the three months ended September 30, 2010, WRDC (i) was not assessed any Mine Act section 110(b)(2) penalties for failure to correct the subject matter of a Mine Act section 104(a) citation within the specified time period, which failure was deemed flagrant (i.e., a reckless or repeated failure to make reasonable efforts to eliminate a known violation that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury); (ii) did not receive any Mine Act section 107(a) imminent danger orders to immediately remove miners; or (iii) did not receive any MSHA written notices under Mine Act section 104(e) of a pattern of violation of mandatory health or safety standards or of the potential to have such a pattern. In addition, there were no fatalities at the mine during the three months ended September 30, 2010.

The table below sets forth the total number of section 104 citations and/or orders issued by MSHA to WRDC under the indicated provisions of the Mine Act, together with the total dollar value of proposed MSHA assessments, received during the three months ended September 30, 2010 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for each of our mining complexes. All citations were abated within 24 hours of issue.

Mine Act Section 104 Significant and Substantial Citations	Mine Act Section 104(b) Orders	Mine Act Section 104(d) Citations and Orders	Mine Act Section 107(a) Imminent Danger Orders	Total Dollar Value of Proposed MSHA Assessments	Number of Legal Actions Pending Before the Federal Mining Safety and Health Review Commission
5	—	—	—	$6,300	2

ITEM 6. Exhibits

Exhibit 4	Third Supplemental Indenture dated as of July 16, 2010, between the Company and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4 to the Company's Form 8-K filed on July 15, 2010 and incorporated by reference herein).
Exhibit 10.1	Fifth Amendment to Third Amendment and Restated Credit Agreement effective July 12, 2010, among Enserco Energy, Inc., as borrower, BNP Paribas, as administrative agent, collateral agent and the document agent, as an issuing bank, and a bank, Societe Generale, as an issuing bank, a bank and the syndication agent, and each of the other financial institutions which are parties thereto (filed as Exhibit 10 to the Company's Form 8-K filed on July 13, 2010 and incorporated by reference herein).
Exhibit 10.2	Sixth Amendment to Third Amendment and Restated Credit Agreement effective September 21, 2010, among Enserco Energy, Inc., as borrower, BNP Paribas, as administrative agent, collateral agent and the document agent, as an issuing bank, and a bank, Societe Generale, as an issuing bank, a bank and the syndication agent, and each of the other financial institutions which are parties thereto.
Exhibit 10.3	Change in Control Agreement dated September 7, 2010 between Black Hills Corporation and David R. Emery filed as Exhibit 10.1 to the Company's Form 8-K (filed on September 10, 2010 and incorporated by reference herein).
Exhibit 10.4	Form of Change in Control Agreement dated September 7, 2010 between Black Hills Corporation and its Non-CEO Senior Executive Officers (filed on September 10, 2010 and incorporated by reference herein).
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
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Exhibit 101	Financials for XBRL Format

BLACK HILLS CORPORATION

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BLACK HILLS CORPORATION

/s/ David R. Emery
David R. Emery, Chairman, President and
Chief Executive Officer

/s/ Anthony S. Cleberg
Anthony S. Cleberg, Executive Vice President and
Chief Financial Officer

Dated: November 4, 2010

EXHIBIT INDEX

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