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)

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(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

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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

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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

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(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

* 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	$—

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* 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

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

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	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

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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.

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

		Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	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

		Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	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.

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.

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

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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%

(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,		Nine Months Ended September 30,	
	2010	2009	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