BLACK HILLS CORP /SD/
Form 10-Q
November 04, 2011

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, 2011.

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 31, 2011
Common stock, $1.00 par value	39,468,273 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:

AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
ASC	Accounting Standards Codification
ASC 220	ASC 220, "Comprehensive Income"
ASC 350	ASC 350, "Intangibles - Goodwill and Other"
ASC 820	ASC 820, "Fair Value Measurements and Disclosures"
ASU	Accounting Standards Update
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
BHC	Black Hills Corporation
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
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
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	United States Commodities Futures 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
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
CT	Combustion Turbine

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De-designated interest rate swaps	The $250 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
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
Enserco	Enserco Energy Inc., representing our Energy Marketing segment, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Equity Forward Agreement	Equity Forward Agreement with J.P. Morgan connected to a public offering of 4,413,519 shares of Black Hills Corporation common stock
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles of the United States
Global Settlement	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
IFRS	International Financial Reporting Standards
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
IRS	Internal Revenue Service
IUB	Iowa Utilities Board
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	One thousand standard cubic feet
Mcfe	One thousand standard cubic feet equivalent
MMBtu	One million British thermal units
MSHA	Mine Safety and Health Administration
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
PGA	Purchase Gas Adjustment
PPA	Power Purchase Agreement
PPACA	Patient Protection and Affordability Care Act
PSCo	Public Service Company of Colorado
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
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

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BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands, except per share amounts)			
Operating revenue:				
Utilities	$223,714	$212,193	$834,463	$821,027
Non-regulated energy	32,746	37,301	98,422	111,305
Total operating revenue	256,460	249,494	932,885	932,332
Operating expenses:				
Utilities -				
Fuel, purchased power and cost of gas sold	86,127	86,933	400,465	420,747
Operations and maintenance	58,313	57,294	184,411	188,357
Gain on sale of operating assets	—	(6,238)	—	(8,921)
Non-regulated energy operations and maintenance	27,898	26,018	85,468	74,084
Depreciation, depletion and amortization	33,374	30,036	97,695	88,691
Taxes - property, production and severance	9,050	7,426	24,510	20,142
Other operating expenses	259	83	562	753
Total operating expenses	215,021	201,552	793,111	783,853
Operating income	41,439	47,942	139,774	148,479
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premium and discount, realized settlements on interest rate swaps)	(29,697)	(27,827)	(88,418)	(78,941)
Allowance for funds used during construction - borrowed	3,520	1,934	9,874	7,804
Capitalized interest	2,981	1,614	8,198	2,470
Interest rate swaps - unrealized (loss) gain	(38,246)	(13,710)	(40,608)	(41,663)
Interest income	563	199	1,598	529
Allowance for funds used during construction - equity	189	375	676	2,663
Other income, net	524	539	1,761	2,225
Total other income (expense)	(60,166)	(36,876)	(106,919)	(104,913)
Income (loss) before equity in earnings (loss) of unconsolidated subsidiaries and income taxes	(18,727)	11,066	32,855	43,566
Equity in earnings (loss) of unconsolidated subsidiaries	43	(137)	1,076	1,471
Income tax benefit (expense)	8,159	1,461	(9,794)	(9,872)
Net income (loss)	$(10,525)	$12,390	$24,137	$35,165
Weighted average common shares outstanding:				

Basic	39,145	38,933	39,105	38,895
Diluted	39,145	39,133	39,792	39,052
Earnings (loss) per share - basic	$(0.27)	$0.32	$0.62	$0.90
Earnings (loss) per share - diluted	$(0.27)	$0.32	$0.61	$0.90
Dividends paid per share of common stock	$0.365	$0.360	$1.095	$1.080

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, 2011 (in thousands)	December 31, 2010	September 30, 2010
ASSETS			
Current assets:			
Cash and cash equivalents	$74,779	$32,438	$58,975
Restricted cash	4,080	4,260	17,082
Accounts receivable, net	241,831	328,811	234,480
Materials, supplies and fuel	134,463	139,677	145,251
Derivative assets, current	48,727	56,572	71,688
Income tax receivable, net	10,958	—	25,156
Deferred income tax assets, current	39,628	17,113	15,073
Regulatory assets, current	45,713	66,429	55,941
Other current assets	65,889	25,571	20,932
Total current assets	666,068	670,871	644,578
Investments	17,338	17,780	17,981
Property, plant and equipment	3,664,967	3,359,762	3,243,641
Less accumulated depreciation and depletion	(934,112)	(864,329)	(880,938)
Total property, plant and equipment, net	2,730,855	2,495,433	2,362,703
Other assets:			
Goodwill	354,831	354,831	353,734
Intangible assets, net	3,899	4,069	4,129
Derivative assets, non-current	17,215	9,260	12,762
Regulatory assets, non-current	142,267	138,405	124,134
Other assets, non-current	20,894	20,860	20,216
Total other assets	539,106	527,425	514,975
TOTAL ASSETS	$3,953,367	$3,711,509	$3,540,237

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, 2011	December 31, 2010	September 30, 2010
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$219,167	$279,069	$201,072
Accrued liabilities	168,640	170,301	166,977
Derivative liabilities, current	129,163	79,167	108,318
Accrued income taxes, net	—	779	—
Regulatory liabilities, current	10,568	3,943	12,368
Notes payable	359,000	249,000	145,000
Current maturities of long-term debt	2,893	5,181	5,314
Total current liabilities	889,431	787,440	639,049
Long-term debt, net of current maturities	1,282,194	1,186,050	1,188,293
Deferred credits and other liabilities:			
Deferred income tax liabilities, non-current	329,833	277,136	279,315
Derivative liabilities, non-current	26,603	21,361	25,892
Regulatory liabilities, non-current	85,074	84,611	79,393
Benefit plan liabilities	124,214	124,709	122,178
Other deferred credits and other liabilities	128,013	129,932	125,710
Total deferred credits and other liabilities	693,737	637,749	632,488
Stockholders' equity:			
Common stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 39,491,616, 39,280,048 and 39,243,257 shares, respectively	39,492	39,280	39,243
Additional paid-in capital	604,945	598,805	597,108
Retained earnings	467,043	486,075	466,691
Treasury stock at cost – 28,041, 10,962 and 7,905 shares, respectively	(810)	(309)	(226)
Accumulated other comprehensive income (loss)	(22,665)	(23,581)	(22,409)
Total stockholders' equity	1,088,005	1,100,270	1,080,407
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,953,367	$3,711,509	$3,540,237

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,	
	2011	2010
Operating activities:	(in thousands)	
Net income (loss)	$24,137	$35,165
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	97,695	88,691
Derivative fair value adjustments	9,605	(10,690)
Gain on sale of operating assets	—	(8,921)
Stock compensation	4,931	2,908
Unrealized mark-to-market loss (gain) on interest rate swaps	40,608	41,663
Deferred income taxes	26,280	32,366
Equity in (earnings) loss of unconsolidated subsidiaries	(1,076)	(1,471)
Allowance for funds used during construction - equity	(676)	(2,663)
Employee benefit plans	10,930	12,214
Other, net	9,702	6,663
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	12,592	(40,344)
Accounts receivable and other current assets	29,631	8,754
Accounts payable and other current liabilities	(73,489)	(21,295)
Regulatory assets	22,357	(2,205)
Regulatory liabilities	5,041	7,176
Contributions to defined pension plans	(11,050)	(30,015)
Other operating activities	(691)	7,765
Net cash provided by operating activities	206,527	125,761
Investing activities:		
Property, plant and equipment additions	(328,496)	(323,883)
Proceeds from sale of operating assets	583	68,105
Payment for acquisition of assets	—	(2,250)
Other investing activities	1,051	4,273
Net cash provided by (used in) investing activities	(326,862)	(253,755)
Financing activities:		
Dividends paid	(43,169)	(42,331)
Common stock issued	2,199	3,073
Short-term borrowings - issuances	770,000	451,500
Short-term borrowings - repayments	(560,000)	(471,000)
Long-term debt - issuances	—	200,000
Long-term debt - repayments	(6,169)	(57,550)
Other financing activities	(185)	(9,624)
Net cash provided by (used in) financing activities	162,676	74,068

Net change in cash and cash equivalents	42,341	(53,926)
Cash and cash equivalents, beginning of period	32,438	112,901
Cash and cash equivalents, end of period	$74,779	$58,975

See Note 3 for supplemental disclosure of cash flow information.

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 2010 Annual Report on Form 10-K)

(1) MANAGEMENT'S STATEMENT

The condensed consolidated financial statements included herein have been prepared by Black Hills Corporation together with our subsidiaries (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 2010 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 adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the September 30, 2011, December 31, 2010 and September 30, 2010 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal and revenue 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, 2011 and September 30, 2010, and our financial condition as of September 30, 2011, December 31, 2010, and September 30, 2010 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 accompanying condensed consolidated financial statements has been reclassified to conform to the current year presentation. Specifically, (a) the Company has reclassified revenue into two categories: Utilities revenue and Non-regulated energy revenue, (b) the categories of Fuel, purchased power and cost of gas sold and Operations and maintenance included in our Operating expenses have been reclassified into Utilities and Non-regulated energy, and (c) the Taxes - property, production and severance line has been reclassified to show only those taxes. Any taxes other than property, production and severance are now included in the respective Utility or Non-regulated energy operations and maintenance lines. Income taxes remain as a separate line item. These reclassifications had no effect on total assets, net income, cash flows or earnings per share.

Restatement - Subsequent to the issuance of the Company's 2010 consolidated financial statements, the Company's management determined that certain intercompany transactions with our rate regulated operations had not been properly eliminated in consolidation, resulting in an overstatement of Utility and Non-regulated energy revenue and Fuel, purchased power and cost of gas sold of $14.8 million and $45.6 million, in aggregate for the three and nine months ended September 30, 2010, respectively. As such, the condensed consolidated financial statements have been restated for the correction of this error. The correction did not have an impact on our gross margin, net income, total assets or cash flows.

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

Recently Adopted Accounting Standards and Legislation

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 is 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 were effective on January 1, 2011. The guidance required additional disclosures, but did not impact our financial position, results of operations or cash flows. The additional disclosures are included in Note 13 of these Notes to Condensed Consolidated Financial Statements.

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 total 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 implications on our financial statements of the PPACA as related regulations and interpretations become available.

Recently Issued Accounting Standards and Legislation

Intangibles - Goodwill and Other, ASU No. 2011-08

The FASB issued an accounting standards update amending ASC 350 which permits entities to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. If an entity believes, as a result of its qualitative assessment, that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the quantitative two-step goodwill impairment test is required. An entity has the unconditional option to bypass the qualitative assessment and proceed directly to performing the first step of the goodwill impairment test. ASU 2011-08 is effective for annual and interim goodwill impairment tests performed in fiscal years beginning after December 15, 2011 with early adoption permitted.

Other Comprehensive Income, ASU No. 2011-05

FASB issued an accounting standards update amending ASC 220 to improve the comparability, consistency and transparency of reporting of comprehensive income. The update amends existing guidance by allowing only two options for presenting the components of net income and other comprehensive income: (1) in a single continuous financial statement, statement of comprehensive income or (2) in two separate but consecutive financial statements, consisting of an income statement followed by a separate statement of other comprehensive income. Also, items that are reclassified from other comprehensive income to net income must be presented on the face of the financial statements. ASU No. 2011-05 requires retrospective application, and it is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, with early adoption permitted. The adoption of this update may change the order in which certain financial statements are presented and provide additional detail on those financial statements when applicable, but will not have any other impact on our consolidated financial statements.

Fair Value Measurement, ASU No. 2011-04

FASB issued an accounting standards update amending ASC 820 to achieve common fair value measurement and disclosure requirements between GAAP and IFRS. Additional disclosure requirements in the update include: (1) for Level 3 fair value measurements, quantitative information about unobservable inputs used, a description of the valuation processes used by the entity, and a qualitative discussion about the sensitivity of the measurements to changes in the unobservable inputs; (2) for an entity's use of a non-financial asset that is different from the asset's highest and best use, the reason for the difference; (3) for financial instruments not measured at fair value but for which disclosure of fair value is required, the fair value hierarchy level in which the fair value measurements were determined; and (4) the disclosure of all transfers between Level 1 and Level 2 of the fair value hierarchy. ASU No. 2011-04 is effective for fiscal years, and interim periods within those years, beginning after December 31, 2011, with early adoption permitted. We do not expect this amendment to have an impact on our financial position, results of operations, or cash flows.

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 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 in order to implement the restrictions, limitations, and requirements contemplated by Dodd-Frank. We will continue to evaluate the impact as these rules become available.

(3) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Nine Months Ended September 30, 2011	September 30, 2010
	(in thousands)	
Non-cash investing activities—		
Property, plant and equipment acquired with accrued liabilities	$49,566	$37,661
Cash (paid) refunded during the period for—		
Interest (net of amounts capitalized)	$(61,461)	$(62,740)
Income taxes, net	$11,826	$(488)

(4) MATERIALS, SUPPLIES AND FUEL

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

	September 30, 2011	December 31, 2010	September 30, 2010
Materials and supplies	$37,611	$31,749	$31,192
Fuel - Electric Utilities	8,639	9,687	9,056
Natural gas in storage — Gas Utilities	38,641	21,691	36,782
Commodities held by Energy Marketing*	49,572	76,550	68,221
Total materials, supplies and fuel	$134,463	$139,677	$145,251

* As of September 30, 2011, December 31, 2010 and September 30, 2010, market adjustments related to natural gas held by Energy Marketing and recorded in inventory as part of fair value hedge transactions were $(1.7) million, $(9.1) million and $(18.7) million, respectively (see Note 12 for further discussion of Energy Marketing activities).

(5) ACCOUNTS RECEIVABLE

Trade Accounts Receivable

Our Accounts receivable represents primarily customer trade accounts at our Electric Utilities and Gas Utilities segments and counterparty trade accounts at our Energy Marketing segment. This balance fluctuates primarily due to the seasonality of our Gas Utilities and volume and commodity prices at our Energy Marketing segment. We maintain an allowance for doubtful accounts that reflects our best estimate of probable uncollectible trade receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect our ability to collect. Following is a summary of receivables (in thousands):

As of September 30, 2011	Accounts Receivable, Trade	Unbilled Revenue	Total Accounts Receivable	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$41,889	$16,401	$58,290	$(590)	$57,700
Gas	21,168	12,518	33,686	(789)	32,897
Oil and Gas	8,820	—	8,820	(161)	8,659
Coal Mining	1,845	—	1,845	—	1,845
Energy Marketing	139,332	—	139,332	(174)	139,158
Power Generation	119	—	119	—	119
Corporate	1,453	—	1,453	—	1,453
Total	$214,626	$28,919	$243,545	$(1,714)	$241,831

As of December 31, 2010	Accounts Receivable, Trade	Unbilled Revenue	Total Accounts Receivable	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$51,005	$19,572	$70,577	$(708)	$69,869
Gas	41,970	40,376	82,346	(1,425)	80,921
Oil and Gas	6,213	—	6,213	(161)	6,052
Coal Mining	2,420	—	2,420	—	2,420
Energy Marketing	157,064	—	157,064	(69)	156,995
Power Generation	307	—	307	—	307
Corporate (a)	12,247	—	12,247	—	12,247
Total	$271,226	$59,948	$331,174	$(2,363)	$328,811

As of September 30, 2010	Accounts Receivable, Trade	Unbilled Revenue	Total Accounts Receivable	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$41,955	$17,959	$59,914	$(927)	$58,987
Gas	19,611	11,107	30,718	(830)	29,888
Oil and Gas	6,112	—	6,112	(161)	5,951
Coal Mining	2,201	—	2,201	—	2,201
Energy Marketing	99,850	—	99,850	(375)	99,475
Power Generation	463	—	463	—	463
Corporate [(a)] [(b)]	37,515	—	37,515	—	37,515
Total	$207,707	$29,066	$236,773	$(2,293)	$234,480

(a) During the third quarter of 2010 we reached a settlement with the IRS and received a refund relating to this settlement during 2011 of $12.0 million, excluding interest income.
(b) includes cash collateral receivable on de-designated interest rate swaps. See Note 12 for further information.

(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, 2011, we were in compliance with these covenants. Our credit facilities and debt securities do not contain default provisions pertaining to our credit ratings.

We had the following short-term debt issued and outstanding as of the Condensed Consolidated Balance Sheet dates (in thousands):

	As of September 30, 2011		As of December 31, 2010		As of September 30, 2010	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$209,000	$42,355	$149,000	$46,900	$145,000	$15,500
Enserco Credit Facility	—	132,625	—	166,900	—	131,500
Term Loan due 2011	—	—	100,000	—	—	—
Term Loan due 2012	150,000	—	—	—	—	—
Total	$359,000	$174,980	$249,000	$213,800	$145,000	$147,000

Revolving Credit Facility

Our $500.0 million Revolving Credit Facility expiring April 14, 2013 contains an accordion feature which allows us, with the consent of the administrative agent, to increase the capacity of the facility to $600.0 million and can be used for the issuance of letters of credit, to fund working capital needs and for other corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The 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 were 1.75%, 2.75% and 2.75%, respectively, at September 30, 2011. The facility contains a commitment fee to be charged on the unused amount of the facility. Based upon current credit ratings, the fee is 0.5%.

Deferred financing costs are being amortized over the term of the facility. The amortization expense is included in Interest expense on the accompanying Condensed Consolidated Statements of Income as follows (in thousands):

	Deferred Financing Costs Remaining on Balance Sheet as of September 30, 2011	Amortization Expense Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Deferred Financing Costs - Revolving Credit Facility	$1,970	$473	$481	$1,419	$866

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, 2011.

As of September 30, 2011	Actual	Covenant Requirement
Consolidated Net Worth	$1,088,000	$871,300
Recourse Leverage Ratio	61.3 %	65.0 %

Enserco Credit Facility

Enserco's $250.0 million committed credit facility expiring May 7, 2012 contains an accordion feature which allows, with the consent of the administrative agent, the commitment under the facility to increase to $350.0 million. Maximum borrowings under the facility are subject to a sub-limit of $50.0 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%. Enserco Credit Facility covenants include tangible net worth, net working capital and realized net working capital requirements. Enserco was in compliance with these covenants as of September 30, 2011.

Deferred financing costs for the Enserco Credit Facility are being amortized over the term of the Enserco Credit Facility. The amortization expense is included in Interest expense on the accompanying Condensed Consolidated Statements of Income as follows (in thousands):

	Deferred Financing Costs Remaining on Balance Sheet as of September 30, 2011	Amortization Expense Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Deferred Financing Costs - Enserco Credit Facility	$812	$305	$263	$866	$1,245

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Corporate Term Loans

On September 30, 2011, we extended our $100.0 million term loan for two-years under the existing terms. This term loan is now due on September 30, 2013.

In June 2011, we entered into a one-year $150.0 million unsecured, single draw, term loan with CoBank, the Bank of Nova Scotia and U.S. Bank due on June 24, 2012. The cost of borrowing under the loan is based on a spread of 125 basis points over LIBOR (1.63% at September 30, 2011). The covenants are substantially the same as those included in the Revolving Credit Facility. We were in compliance with these covenants as of September 30, 2011.

(7) EARNINGS PER SHARE

Basic earnings (loss) per share is computed by dividing net income by the weighted-average number of common shares outstanding during the period. Diluted earnings (loss) per share is computed by using all dilutive common shares potentially outstanding during a period. A reconciliation of share amounts used to compute earnings (loss) per share is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income (loss)	$(10,525)	$12,390	$24,137	$35,165
Weighted average shares - basic	39,145	38,933	39,105	38,895
Dilutive effect of:				
Restricted stock	—	131	147	110
Stock options	—	12	16	9
Forward equity issuance	—	—	473	—
Other	—	57	51	38
Weighted average shares - diluted	39,145	39,133	39,792	39,052

Below is a discussion of our potentially dilutive shares that were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive.

Due to the Company's net loss in the quarter ending September 30, 2011, potentially dilutive securities, consisting of outstanding stock options, restricted common stock, restricted stock units, non-vested performance-based share awards, warrants and forward equity instruments were excluded from the diluted loss per share calculation due to their anti-dilutive effect. In computing diluted net loss per share, 11,880 options to purchase shares of common stock, 159,873 vested and non-vested restricted stock shares, 31,408 warrants and other performance shares and 424,715 forward equity instruments were excluded from the computations for the three months ended September 30, 2011.

In addition to these potentially dilutive shares, 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,	
	2011	2010	2011	2010
Stock options	176	128	119	169

Restricted stock	20	2	17	2
Other stock	27	1	19	1
Anti-dilutive shares	223	131	155	172

(8) COMPREHENSIVE INCOME (LOSS)

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

	Three Months Ended September 30, 2011	
Net income (loss)		$(10,525)
Other comprehensive income (loss), net of tax:		
Benefit plan liability adjustments	$—	
Taxes on benefit plan liability adjustments	—	
Benefit plan liability adjustments, net of tax		—
Fair value adjustment on derivatives designated as cash flow hedges	$3,137	
Taxes on fair value adjustment on derivatives designated as cash flow hedges	(1,215)	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		1,922
Reclassification adjustments on cash flow hedges settled and included in net income (loss)	$414	
Taxes on reclassification adjustment on cash flow hedges settled and included in net income (loss)	(129)	
Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax		285
Comprehensive income (loss)		$(8,318)

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

	Nine Months Ended September 30, 2011	
Net income (loss)		$24,137
Other comprehensive income (loss), net of tax:		
Benefit plan liability adjustments	$—	
Taxes on benefit plan liability adjustments	—	
Benefit plan liability adjustments, net of tax		—
Fair value adjustment on derivatives designated as cash flow hedges	$(1,644)	
Taxes on fair value adjustment on derivatives designated as cash flow hedges	653	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		(991)
Reclassification adjustments on cash flow hedges settled and included in net income (loss)	$2,892	
Taxes on reclassification adjustment on cash flow hedges settled and included in net income (loss)	(985)	
Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax		1,907
Comprehensive income (loss)		$25,053

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

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

	September 30, 2011	December 31, 2010	September 30, 2010
Derivatives designated as cash flow hedges	$(11,523)	$(12,437)	$(12,741)
Benefit plans	(11,142)	(11,142)	(9,636)
Amount from equity-method investees	—	(2)	(32)
Total	$(22,665)	$(23,581)	$(22,409)

(9) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock during the nine months ended September 30, 2011 from the amount reported in Note 11 of the Notes to Consolidated Financial Statements in our 2010 Annual Report on Form 10-K.

Equity Compensation Plans

- We granted 67,389 target performance shares to certain officers and business unit leaders for the January 1, 2011 through December 31, 2013 performance period during the nine months ended September 30, 2011. Actual shares are issued after the end of the performance plan period. 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, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria. The performance awards are paid 50% in the form of cash and 50% in shares of common stock. The grant date fair value was $25.91 per share.

- We issued 14,111 shares of common stock under our short-term incentive compensation plan during the nine months ended September 30, 2011. Pre-tax compensation cost related to the awards was approximately $0.4 million, which was expensed in 2010.

- We granted 136,348 shares of restricted common stock and restricted stock units during the nine months ended September 30, 2011. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $4.1 million will be recognized over the three year vesting period.

- We granted 99,000 stock options at a weighted-average exercise price of $32.04 during the nine months ended September 30, 2011. The total fair value of approximately $0.6 million will be recognized over the three year vesting period.

- Stock options totaling 5,500 shares were exercised during the nine months ended September 30, 2011 at a weighted-average exercise price of $29.94 per share, providing $0.2 million of proceeds.

Total compensation expense recognized for all equity compensation plans for the three months ended September 30, 2011 and 2010 was $1.7 million and $1.9 million, respectively, and for the nine months ended September 30, 2011 and 2010 was $5.0 million and $4.7 million, respectively.

As of September 30, 2011, total unrecognized compensation expense related to non-vested stock awards was $8.5 million and is expected to be recognized over a weighted-average period of 2 years.

Dividend Reinvestment and Stock Purchase Plan

We have a Dividend Reinvestment and Stock Purchase Plan ("DRIP") 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 79,339 new shares at a weighted-average price of $30.81 during the nine months ended September 30, 2011. At September 30, 2011, 476,437 shares of unissued common stock were available for future offering under the DRIP.

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 50.0% of aggregate consolidated net income, if positive, since January 1, 2005. As of September 30, 2011, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders 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, 2011:

- 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, 2011, the restricted net assets at our Utilities Group were approximately $164.3 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, 2011 were $163.8 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.

Forward Equity Instrument

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

(10) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

We have three non-contributory defined benefit pension plans (the "Pension Plans"). One covers certain eligible employees of the following subsidiaries: Black Hills Service Company, Black Hills Power, WRDC and BHEP; one covers certain eligible employees of Cheyenne Light, and one Pension Plan covers certain eligible employees of Black Hills Energy. The Pension Plan benefits are based on years of service and compensation levels.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Service cost	$1,355	$1,533	$4,066	$4,599
Interest cost	3,732	3,773	11,196	11,319
Expected return on plan assets	(4,239)	(3,623)	(12,717)	(10,869)
Prior service cost	25	305	75	915
Net loss (gain)	1,135	500	3,405	1,500
Curtailment expense	—	—	—	—
Net periodic benefit cost	$2,008	$2,488	$6,025	$7,464

Non-pension Defined Benefit Postretirement Healthcare Plans

We sponsor the following 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 were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Service cost	$375	$377	$1,125	$1,131
Interest cost	542	611	1,626	1,833
Expected return on plan assets	(41)	(52)	(123)	(156)
Prior service benefit	(120)	(77)	(360)	(231)
Net transition obligation	—	—	—	—
Net loss (gain)	169	159	507	477
Net periodic benefit cost	$925	$1,018	$2,775	$3,054

It has been determined that our post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy.

Supplemental Non-qualified Defined Benefit Plans

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 were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Service cost	$257	$171	$771	$513
Interest cost	324	321	973	963
Prior service cost	1	1	3	3
Net loss (gain)	128	71	383	213
Net periodic benefit cost	$710	$564	$2,130	$1,692

Contributions

We anticipate that we will make contributions to each of the benefit plans during 2011 and 2012. Contributions to the Healthcare Plans and the Supplemental Plans expected to be made in the form of benefit payments are as follows (in thousands):

	Contributions Made Three Months Ended September 30, 2011	Contributions Made Nine Months Ended September 30, 2011	Contributions Remaining for 2011	Contributions Anticipated for 2012
Defined Benefit Pension Plans	$10,500	$11,050	$—	$7,869
Non-pension Defined Benefit Postretirement Healthcare Plans	$882	$2,646	$882	$3,765
Supplemental Non-qualified Defined Benefit Plans	$235	$705	$236	$896

(11) 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, 2011, 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 to areas 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. 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. In January 2011, we sold our ownership interests in the partnerships which owned the generation facilities in Idaho;

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

- Energy Marketing, which provides natural gas, crude oil, coal, power and environmental marketing and related services in the United States and Canada.

Segment information follows the accounting policies described in Note 1 of the Notes to Consolidated Financial Statements in our 2010 Annual Report on Form 10-K.

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

Three Months Ended September 30, 2011	External Operating Revenue	Inter-segment Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$151,063	$2,653	$15,790
Gas	72,651	—	572
Non-regulated Energy:			
Oil and Gas	19,163	—	241
Power Generation	1,011	7,089	337
Coal Mining	9,184	8,651	555
Energy Marketing	3,388	3,550	273
Corporate [a]	—	—	(27,943)
Inter-segment eliminations	—	(21,943)	(350)
Total	$256,460	$—	$(10,525)

Three Months Ended September 30, 2010	External Operating Revenue	Inter-segment Operating Revenue [d]	Net Income (Loss)
Utilities:			
Electric [b]	$138,761	$2,884	$18,537
Gas [c]	72,323	—	(595)
Non-regulated Energy:			
Oil and Gas [e]	19,354	—	836
Power Generation	1,124	6,731	575
Coal Mining	7,744	6,533	1,673
Energy Marketing	9,060	(87)	1,370
Corporate [a] [f]	—	—	(10,093)
Inter-segment eliminations	—	(14,933)	87
Total	$248,366	$1,128	$12,390

Nine Months Ended September 30, 2011	External Operating Revenue	Inter-segment Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$431,624	$9,902	$34,653
Gas	402,839	—	24,275
Non-regulated Energy:			
Oil and Gas	55,907	—	(553)
Power Generation	2,750	20,750	2,071
Coal Mining	23,064	25,806	(1,124)
Energy Marketing	16,701	5,178	1,327
Corporate [a]	—	—	(36,101)
Inter-segment eliminations	—	(61,636)	(411)
Total	$932,885	$—	$24,137

Nine Months Ended September 30, 2010	External Operating Revenue	Inter-segment Operating Revenue [d]	Net Income (Loss)
Utilities:			
Electric [b]	$415,092	$11,627	$35,585
Gas [c]	402,608	—	18,017
Non-regulated Energy:			
Oil and Gas [e]	57,755	—	3,405
Power Generation	3,266	19,336	1,239
Coal Mining	22,431	20,875	6,093
Energy Marketing	27,797	(157)	4,890
Corporate [a] [f]	—	—	(34,221)
Inter-segment eliminations	—	(48,298)	157
Total	$928,949	$3,383	$35,165

(a) Net income (loss) includes a $24.9 million and a $26.4 million net after-tax mark-to-market loss on interest rate swaps for the three and nine months ended September 30, 2011 and an $8.9 million and $27.1 million net after-tax loss on interest rate swaps for the three and nine months ended September 30, 2010, respectively.
(b) Net income (loss) includes a $4.1 million after-tax gain on sale of a 23% interest in Wygen III to the City of Gillette.
(c) Net income (loss) includes a $1.7 million after-tax gain on sale of operating assets in the Gas Utilities at Nebraska Gas.
(d) Total operating revenue has been restated to reflect elimination of intercompany activities previously not eliminated. See Note 1 for further information.
(e) Net income (loss) includes a $0.4 million reduction of income taxes as a result of a re-measurement of a previously reported uncertain tax position due to a settlement with the IRS.
(f) Net income (loss) includes a $2.0 million reduction in income tax expense reflecting a re-measurement of an uncertain tax position due to a settlement agreement that was reached with the IRS primarily due to tax depreciation method changes.

Total assets	September 30, 2011	December 31, 2010	September 30, 2010
Utilities:			
Electric [a]	$1,917,183	$1,834,019	$1,771,014
Gas	683,163	722,287	659,801
Non-regulated Energy:			
Oil and Gas	405,513	349,991	358,113
Power Generation [a]	372,313	293,334	249,778
Coal Mining	94,908	96,962	94,149
Energy Marketing	340,499	314,930	287,173
Corporate	139,788	99,986	120,209
Total assets	$3,953,367	$3,711,509	$3,540,237

(a) Includes 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; both facilities are currently under construction and are expected to be completed by December 31, 2011.

(12) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors 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 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 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 2010 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 below and within Note 13.

Trading Activities

Our Energy Marketing segment is engaged in marketing natural gas, crude oil, coal, power and environmental products, specializing in producer services, end-use origination and wholesale marketing in the United States and Canada. Coal marketing activity began June 1, 2010, Power marketing began late in the third quarter of 2010, and Environmental marketing began late in the third quarter of 2010 with no significant activity until the second quarter of 2011.

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 revenue 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 Energy Marketing Risk Management Policies and Procedures as approved by our Executive Risk Committee.

We use a number of quantitative tools to measure, monitor and limit our exposure to market risk in our 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 marketing activities and derivative commodity instruments were as follows:

	Outstanding at September 30, 2011		Outstanding at December 31, 2010		Outstanding at September 30, 2010	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(notional in thousands of MMBtus)						
Natural gas basis swaps purchased	425,360	42	399,128	22	335,805	25
Natural gas basis swaps sold	443,489	42	426,903	22	358,929	25
Natural gas fixed-for-float swaps purchased	251,602	27	135,005	33	84,636	36
Natural gas fixed-for-float swaps sold	249,808	27	150,803	22	97,210	18
Natural gas physical purchases	105,446	27	144,948	36	135,818	18
Natural gas physical sales	122,232	72	143,021	36	136,530	36
Natural gas futures purchased	78,100	7	—	—	—	—
Natural gas futures sold	96,730	7	—	—	—	—
Natural gas options purchased	6,000	2	—	—	—	—
Natural gas options sold	6,000	2	—	—	—	—

	Outstanding at September 30, 2011		Outstanding at December 31, 2010		Outstanding at September 30, 2010	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(notional in thousands of Bbls)						
Crude oil physical purchases	7,326	15	5,628	16	5,561	15
Crude oil physical sales	7,917	15	6,921	16	4,759	15
Crude oil fixed-for-float swaps purchased	—	—	20	3	135	1
Crude oil fixed-for-float swaps sold	10	2	240	4	289	3

	Outstanding at September 30, 2011		Outstanding at December 31, 2010		Outstanding at September 30, 2010	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(notional in thousands of tons)						
Coal fixed-for-float swaps purchased	8,305	27	4,060	36	5,585	39
Coal fixed-for-float swaps sold	9,710	27	3,720	36	4,445	39
Coal physical purchases	27,982	39	24,634	48	24,100	51
Coal physical sales	13,331	39	9,046	36	6,213	35
Coal options purchased	4,530	51	2,835	48	1,980	27
Coal options sold	572	6	270	12	360	15

(notional in thousands of MWh):	Outstanding at September 30, 2011 Notional Amounts	Outstanding at September 30, 2011 Latest Expiration (months)	Outstanding at December 31, 2010 Notional Amounts	Outstanding at December 31, 2010 Latest Expiration (months)	Outstanding at September 30, 2010 Notional Amounts	Outstanding at September 30, 2010 Latest Expiration (months)
Power physical purchases	153	54	—	—	—	—
Power physical sales	153	54	—	—	—	—
Power fixed-for-float swaps purchased	12,370	27	—	—	—	—
Power fixed-for-float swaps sold	12,439	27	—	—	—	—

(notional in thousands of MWh):	Outstanding at September 30, 2011 Notional Amounts	Outstanding at September 30, 2011 Latest Expiration (months)	Outstanding at December 31, 2010 Notional Amounts	Outstanding at December 31, 2010 Latest Expiration (months)	Outstanding at September 30, 2010 Notional Amounts	Outstanding at September 30, 2010 Latest Expiration (months)
Environmental products physical purchases	283	54	—	—	—	—
Environmental products physical sales	273	54	—	—	—	—

Derivatives and certain other marketing transactions were marked to fair value at September 30, 2011, December 31, 2010 and September 30, 2010, and the related gains and/or losses recognized in earnings. The amounts included in the accompanying Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Income were as follows (in thousands):

	September 30, 2011	December 31, 2010	September 30, 2010
Current derivative assets	$36,550	$43,862	$55,366
Non-current derivative assets	$13,969	$6,635	$8,023
Current derivative liabilities	$27,851	$14,550	$17,743
Non-current derivative liabilities	$4,128	$3,464	$1,277
Cash collateral receivable (payable) included in derivative assets/liabilities	$9,026	$3,958	$(7,365)
Unrealized gains	$9,514	$28,525	$51,734
Net derivative assets (liabilities) with credit risk-related contingent features that require Enserco to maintain a specific credit rating	$—	$—	$—
Cash collateral receivable included in Other current assets	$34,642	$9,919	$1,854
Cash collateral (payable) included in Other current liabilities	$(802)	$(1,079)	$(1,079)

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 or loss on the Condensed Consolidated Statements of Income, effectively offsetting the earnings impact of the unrealized gain or loss recognized on the associated derivative asset or liability described above. As of September 30, 2011, December 31, 2010 and September 30, 2010, the market adjustments recorded in inventory were $(1.7) million, $(9.1) million and $(18.7) 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.

We held 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 Accumulated other comprehensive income (loss) and the ineffective portion, if any, is reported in earnings.

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

	September 30, 2011		December 31, 2010		September 30, 2010	
	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps
Notional*	414,000	4,957,250	424,500	6,821,800	484,500	8,109,800
Maximum terms in years **	1.00	0.25	0.25	0.25	0.25	0.25
Derivative assets, current	$1,885	$6,937	$248	$7,675	$466	$8,816
Derivative assets, non-current	$2,529	$717	$19	$2,606	$216	$4,523
Derivative liabilities, current	$—	$—	$3,814	$—	$3,224	$—
Derivative liabilities, non-current	$—	$7	$1,301	$—	$497	$—
Pre-tax accumulated other comprehensive income (loss) included in Condensed Consolidated Balance Sheets	$4,257	$7,647	$(5,313)	$10,281	$(3,611)	$13,339
Earnings	$157	$—	$465	$—	$572	$—

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* Crude oil in Bbls, gas in MMBtus

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

Based on September 30, 2011 market prices, an $8.3 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 fluctuate.

Gas Utilities - Gas Hedges

Our Gas Utilities segment 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 transactions, which may include 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 Condensed Consolidated Statements of Income as a component of PGA costs when the related costs are recovered through our rates as part of PGA costs in operating revenue.

The contract or notional amounts and terms of our natural gas derivative commodity instruments held at our Gas Utilities were as follows:

	Outstanding at September 30, 2011		Outstanding at December 31, 2010		Outstanding at September 30, 2010	
(notional in MMBtus)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
Natural gas futures purchased	9,890,000	18	6,670,000	15	11,800,000	18
Natural gas options purchased	3,880,000	6	1,730,000	3	3,980,000	6
Natural gas basis swaps purchased	—	—	—	—	—	—

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

	September 30, 2011	December 31, 2010	September 30, 2010
Current derivative assets	$3,355	$4,787	$6,685
Non-current derivative assets	$—	$—	$—
Non-current derivative liabilities	$1,360	$1,620	$2,600
Net unrealized gain (loss) included in regulatory assets or regulatory liabilities	$(11,813)	$(8,030)	$(18,381)
Cash collateral receivable (payable) included in derivative assets/liabilities	$12,058	$10,355	$20,519
Option premium included in Derivative assets, current	$1,750	$842	$1,947

Financing Activities

We are exposed to interest rate risk associated with fluctuations in the interest rate on our variable interest rate debt. 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, 2011		December 31, 2010		September 30, 2010	
	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	5.25	0.25	6.00	1.00	6.25	0.25
Derivative liabilities, current	$6,724	$94,588	$6,823	$53,980	$6,901	$80,450
Derivative liabilities, non-current	$21,108	$—	$14,976	$—	$21,518	$—
Pre-tax accumulated other comprehensive loss included in Condensed Consolidated Balance Sheets	$(27,832)	$—	$(21,799)	$—	$(28,419)	$—
Pre-tax (loss) gain included in Condensed Consolidated Statements of Income	$—	$(40,608)	$—	$(15,193)	$—	$(41,663)
Cash collateral receivable (payable) included in accounts receivable	$—	$—	$—	$—	$—	$25,000

* Maximum terms in years reflect the amended mandatory early termination dates. If the mandatory early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date. If extended annually, de-designated swaps totaling $100 million terminate in 7.25 years and de-designated swaps totaling $150 million terminate in 17.25 years.

Based on September 30, 2011 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $6.7 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will likely change during the next 12 months as market interest rates change. Note 13 provides further information related to the swaps that are not designated as hedges for accounting purposes.

Foreign Exchange Transactions

Our Energy Marketing segment conducts its 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. Any balances that represent Canadian transactions are translated to United States dollars at the end of each accounting period at the exchange rate in effect at the balance sheet dates.

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

	As of September 30, 2011		As of December 31, 2010		As of September 30, 2010	
	Outstanding Notional Amounts	Latest Expiration (Months)	Outstanding Notional Amounts	Latest Expiration (Months)	Outstanding Notional Amounts	Latest Expiration (Months)
Canadian dollars purchased	$—	—	$15,000	1	$5,000	1
Canadian dollars sold	$—	—	$—	—	$—	—

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

	As of September 30, 2011	As of December 31, 2010	As of September 30, 2010
Fair Value of foreign exchange contracts	$—	$(143)	$(11)

The table below includes gains (losses) recognized for foreign exchange contracts and foreign exchange re-measurement of assets and liabilities to our functional currency included in Operating revenue on the accompanying Condensed Consolidated Statements of Income (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Unrealized foreign exchange gain (loss)	$783	$97	$621	$181
Realized foreign exchange gain (loss)	$(529)	$(61)	$(91)	$(652)

(13) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

Assets and liabilities carried at fair value are classified and disclosed in one of the following 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 (in thousands):

	As of September 30, 2011					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Energy Marketing	$—	$370,586	$9,193	$(325,992)	$(3,268)	$50,519
Commodity derivatives — Oil and Gas	—	11,740	328	—	—	12,068
Commodity derivatives — Regulated Utilities Group	—	(8,703)	—	—	12,058	3,355
Money market funds	9,006	—	—	—	—	9,006
Total	$9,006	$373,623	$9,521	$(325,992)	$8,790	$74,948
Liabilities:						
Commodity derivatives — Energy Marketing	$—	$365,646	$4,619	$(325,992)	$(12,294)	$31,979
Commodity derivatives — Oil and Gas	—	7	—	—	—	7
Commodity derivatives — Regulated Utilities Group	—	1,360	—	—	—	1,360
Foreign currency derivatives	—	—	—	—	—	—
Interest rate swaps	—	122,420	—	—	—	122,420
Total	$—	$489,433	$4,619	$(325,992)	$(12,294)	$155,766

	As of December 31, 2010					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Energy Marketing	$—	$166,405	$7,976	$(122,639)	$(1,410)	$50,332
Commodity derivatives — Oil and Gas	—	10,281	266	—	—	10,547
Commodity derivatives — Regulated Utilities Group	—	(5,568)	—	—	10,355	4,787
Money market funds	8,050	—	—	—	—	8,050
Foreign currency derivatives	—	166	—	—	—	166
Total	$8,050	$171,284	$8,242	$(122,639)	$8,945	$73,882
Liabilities:						
Commodity derivatives — Energy Marketing	$—	$143,537	$2,463	$(122,639)	$(5,368)	$17,993
Commodity derivatives — Oil and Gas		5,115	—	—	—	5,115
Commodity derivatives — Regulated Utilities Group	—	1,620	—	—	—	1,620
Foreign currency derivatives	—	21	—	—	—	21
Interest rate swaps	—	75,779	—	—	—	75,779
Total	$—	$226,072	$2,463	$(122,639)	$(5,368)	$100,528

	As of September 30, 2010					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Energy Marketing	$—	$221,740	$3,246	$(154,306)	$(7,387)	$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
Foreign currency derivatives	—	—	—	—	—	—
Total	$10,050	$221,817	$3,808	$(154,306)	$13,131	$94,500
Liabilities:						
Commodity derivatives — Energy Marketing	$—	$172,401	$840	$(154,305)	$(22)	$18,914
Commodity derivatives — Oil and Gas	—	3,720	—	—	—	3,720
Commodity derivatives — Regulated Utilities Group	—	2,696	—	—	—	2,696
Foreign currency derivatives	—	11	—	—	—	11
Interest rate swaps	—	108,869	—	—	—	108,869
Total	$—	$287,697	$840	$(154,305)	$(22)	$134,210

The following tables present the changes in level 3 recurring fair value for the three and nine months ended September 30, 2011 and 2010, respectively (in thousands):

	Three Months Ended September 30, 2011 Commodity Derivatives	Nine Months Ended September 30, 2011 Commodity Derivatives
Balance as of beginning of period	$6,427	$5,779
Unrealized losses	(4,359)	(6,981)
Unrealized gains	2,317	7,870
Purchases	—	—
Issuances	—	—
Settlements	197	(1,761)
Transfers into level 3 [(a)]	254	—
Transfers out of level 3[(b)]	66	(5)
Balances at end of period	$4,902	$4,902
Changes in unrealized gains relating to instruments still held as of period-end	$1,067	$1,307

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	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
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 losses relating to instruments still held as of period-end	$(528)	$1,283

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(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.

Realized and unrealized gains (losses) for level 3 commodity derivatives totaling $(1.7) million and $1.3 million for the three and nine months ended September 30, 2011, respectively, are included in Operating revenue on the accompanying Condensed Consolidated Statements of Income while $(0.3) million and $(0.4) million was recorded through Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets for the three and nine months ended September 30, 2011, 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 $21.1 million, $14.3 million and $13.2 million on deposit in margin accounts at September 30, 2011, December 31, 2010, and September 30, 2010, respectively, to collateralize certain financial instruments, which are included in Derivative assets - current, Derivative assets - non-current, Derivative liabilities - current and/or Derivative liabilities - non-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 12.

The following tables present the fair value and balance sheet classification of our derivative instruments (in thousands):

As of September 30, 2011

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$198	$2
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	2,474	738
Commodity derivatives	Derivative liabilities — non-current	—	—
Interest rate swaps	Derivative liabilities — current	—	6,724
Interest rate swaps	Derivative liabilities — non-current	—	21,108
Total derivatives designated as hedges		$2,672	$28,572
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$54,747	$17,996
Commodity derivatives	Derivative assets — non-current	19,890	2,675
Commodity derivatives	Derivative liabilities — current	344,799	384,729
Commodity derivatives	Derivative liabilities — non-current	44,799	49,255
Foreign currency derivatives	Derivative liabilities — current	—	—
Interest rate swaps	Derivative liabilities — current	—	94,588
Total derivatives not designated as hedges		$464,235	$549,243

As of December 31, 2010

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$10,952	$1,452
Commodity derivatives	Derivative assets — non-current	48	71
Commodity derivatives	Derivative liabilities — current	—	45
Commodity derivatives	Derivative liabilities — non-current	—	—
Interest rate swaps	Derivative liabilities — current	—	6,823
Interest rate swaps	Derivative liabilities — non-current	—	14,976
Total derivatives designated as hedges		$11,000	$23,367
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$149,936	$113,364
Commodity derivatives	Derivative assets — non-current	12,382	3,099
Commodity derivatives	Derivative liabilities — current	20,588	42,865
Commodity derivatives	Derivative liabilities — non-current	978	7,363
Foreign currency derivatives	Derivative assets — current	166	21
Interest rate swaps	Derivative liabilities — current	—	53,980
Total derivatives not designated as hedges		$184,050	$220,692

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
Interest rate swaps	Derivative liabilities — current	—	80,450
Interest rate swaps	Derivative liabilities — non-current	—	—
Foreign currency derivatives	Derivative asset — current	—	11
Foreign currency derivatives	Derivative liabilities — current	—	—
Total derivatives not designated as hedges		$234,156	$287,496

Our derivative activities are discussed in Note 12. 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, 2011.

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 was as follows (in thousands):

		Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011
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	$1,235	$(7,502)
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	(1,100)	7,379
		$135	$(123)

		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	

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Cash Flow Hedges

The impact of cash flow hedges on our Condensed Consolidated Statements of Income was as follows (in thousands):

Three Months Ended September 30, 2011

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of 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	$(6,958)	Interest expense	$(1,930)		$—
Commodity derivatives	10,095	Operating revenue	1,516	Operating revenue	—
Total	$3,137		$(414)		$—

Three Months Ended September 30, 2010

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	$30,227	Interest expense	$(1,859)		$—
Commodity derivatives	(24,912)	Operating revenue	14,540	Operating revenue	(134)
Total	$5,315		$12,681		$(134)

Nine Months Ended September 30, 2011

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$(11,428)	Interest expense	$(5,741)		$—
Commodity derivatives	9,784	Operating revenue	2,849	Operating revenue	—
Total	$(1,644)		$(2,892)		$—

Nine Months Ended September 30, 2010

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative	Location of Gain/(Loss) Reclassified from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income	Location of Gain/(Loss) Recognized in Income on Derivative	Amount of Gain/(Loss) Recognized in Income on Derivative

	(Effective Portion)	(Effective Portion)	(Effective Portion)	(Ineffective Portion)	(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)

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments that have not been designated as hedges on our Condensed Consolidated Statements of Income was as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended September 30, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income	Nine Months Ended September 30, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$(18,529)	$(14,321)
Interest rate swaps - unrealized	Interest rate swaps — unrealized (loss) gain	(38,246)	(40,608)
Interest rate swaps - realized	Interest expense	(3,373)	(10,077)
Foreign currency contracts	Operating revenue	—	(143)
		$(60,148)	$(65,149)

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 swaps - unrealized	Interest rate swaps — 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)

(14) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair value of our financial instruments was as follows (in thousands):

	September 30, 2011		December 31, 2010		September 30, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$74,779	$74,779	$32,438	$32,438	$58,975	$58,975
Restricted cash	$4,080	$4,080	$4,260	$4,260	$17,082	$17,082
Derivative financial instruments - assets	$65,942	$65,942	$65,832	$65,832	$84,450	$84,450
Derivative financial instruments - liabilities	$155,766	$155,766	$100,528	$100,528	$134,210	$134,210
Notes payable	$359,000	$359,000	$249,000	$249,000	$145,000	$145,000
Long-term debt, including current maturities	$1,285,087	$1,430,271	$1,191,231	$1,290,519	$1,193,607	$1,303,338

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

The carrying amounts of our restricted cash approximate fair value due to the short maturity of these instruments.

Restricted cash is primarily related to cash held in escrow required by Black Hills Wyoming project financing agreements. These funds are held in 30-day guaranteed investment certificates of $1.2 million, $3.6 million and $10.6 million for September 30, 2011, December 31, 2010 and September 30, 2010, respectively.

At September 30, 2010, $6.2 million was held at our Oil and Gas segment in accordance with terms of a settlement.

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 12 and 13.

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.

(15) 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 2010 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 2011.

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, 2011 cannot be reasonably determined and could have a material effect on our results of operations or financial position.

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. Total cost of construction is expected to be approximately $227.0 million for Colorado Electric and approximately $260.0 million for the Power Generation segment. Construction is expected to be completed at both facilities by December 31, 2011. We have procured contracts for the turbines, building construction and labor. As of September 30, 2011, we have committed contracts for 100% of the construction for the Colorado Electric utility and 100% of the construction for the Power Generation segment.

PPA Extension

In June 2011, FERC approved an extension of the PPA between Black Hills Wyoming and Cheyenne Light which was due to expire in August 2011. This agreement, now extended through August 2014, provides energy and capacity to Cheyenne Light from Black Hills Wyoming's Gillette CT.

(16) GUARANTEES

We had provided a guarantee for up to $7.0 million of Enserco's obligations under an agency agreement. During the first quarter of 2011, the guarantee expired upon fulfillment of all obligations under the contract.

The construction of the office building in Papillion, Nebraska was completed and the guarantee for $6.0 million was terminated upon purchase of the building on April 1, 2011.

In June 2011, a guarantee to Colorado Interstate Gas was amended. It was amended to increase the guarantee amount to $10.0 million and extend the expiration date to July 31, 2012. All other terms remained the same.

In June 2011, we issued a guarantee to Cross Timbers Energy Services for the performance and payment obligations of Black Hills Utility Holdings for natural gas supply purchases up to $7.5 million. The guarantee expires on June 30, 2012 or upon 30 days written notice to the counterparty.

In July 2011, we issued a $33.3 million guarantee to Vestas-American Wind Technology, Inc. for the performance and payment obligations of Colorado Electric relating to the purchase of wind turbines for a Colorado Electric wind power generation project. This guarantee will remain in effect until satisfaction of Colorado Electric's contractual obligations. We expect the guarantee to expire on or about January 15, 2013.

(17) SUBSEQUENT EVENT

Equity Forward Instrument

On November 1, 2011, we settled the equity forward agreements by physically delivering 4,413,519 shares of common stock and we received cash proceeds of approximately $120 million The price used to determine cash proceeds was calculated based on the November 2010 public offering price of our common stock, adjusted for underwriting fees, as well as a daily adjustment based on the federal funds rate less a spread, and a decrease to reflect the dividend paid on our common stock subsequent to November 10, 2010.

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	Electric Utilities Gas Utilities
Non-regulated Energy	Oil and Gas Power Generation Coal Mining Energy Marketing

Our Utilities Group consists of our Electric and Gas Utilities segments. Our Electric Utilities generate, transmit and distribute electricity to approximately 201,000 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 34,500 customers in Wyoming. Our Gas Utilities serve approximately 527,000 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 from our generating plants and the sale of electric power and capacity primarily under long-term contracts; and the marketing of natural gas, crude oil, coal, power, environmental products and related services in the United States and Canada.

Certain industries in which we operate are highly seasonal, and revenue 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 prices. 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, 2011, and our financial condition as of September 30, 2011, December 31, 2010, and September 30, 2010 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 70.

The following business group and segment information does not include intercompany eliminations. Minor differences in amounts may result due to rounding. All amounts are presented on a pre-tax basis unless otherwise indicated.

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net loss for the three months ended September 30, 2011 was $10.5 million, or $0.27 per share, compared to Net income of $12.4 million, or $0.32 per share, reported for the same period in 2010. The 2011 Net loss included a $24.9 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps. The 2010 Net income included an $8.9 million after-tax unrealized mark-to-market loss on these same interest rate swaps, a $4.1 million after-tax gain on the sale of a 23% ownership interest in Wygen III and a $2.4 million favorable tax adjustment for a re-measurement of certain tax positions.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net income for the nine months ended September 30, 2011 was $24.1 million, or $0.61 per share, compared to $35.2 million, or $0.90 per share, reported for the same period in 2010. The 2011 Net income included a $26.4 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps. The 2010 Net income included a $27.1 million after-tax mark-to-market unrealized loss on these same interest rate swaps, a $5.8 million after-tax gain on the sale of assets of Nebraska Gas and of a 23% ownership interest in Wygen III and a $2.4 million favorable tax adjustment for a re-measurement of certain tax positions.

	Three Months Ended September 30, 2011	2010	Increase (Decrease)	Nine Months Ended September 30, 2011	2010	Increase (Decrease)
	(in thousands)					
Operating revenue *						
Utilities	$226,367	$213,968	$12,399	$844,365	$829,327	$15,038
Non-regulated Energy	52,036	50,459	1,577	150,156	151,303	(1,147)
Intercompany eliminations	(21,943)	(14,933)	(7,010)	(61,636)	(48,298)	(13,338)
	$256,460	$249,494	$6,966	$932,885	$932,332	$553
Net income (loss)						
Electric Utilities	$15,790	$18,537	$(2,747)	$34,653	$35,585	$(932)
Gas Utilities	572	(595)	1,167	24,275	18,017	6,258
Utilities	16,362	17,942	(1,580)	58,928	53,602	5,326
Oil and Gas	241	836	(595)	(553)	3,405	(3,958)
Power Generation	337	575	(238)	2,071	1,239	832
Coal Mining	555	1,673	(1,118)	(1,124)	6,093	(7,217)
Energy Marketing	273	1,370	(1,097)	1,327	4,890	(3,563)
Non-regulated Energy	1,406	4,454	(3,048)	1,721	15,627	(13,906)
Corporate	(27,943)	(10,093)	(17,850)	(36,101)	(34,221)	(1,880)
Inter-company eliminations	(350)	87	(437)	(411)	157	(568)
	$(10,525)	$12,390	$(22,915)	$24,137	$35,165	$(11,028)

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

Business Group highlights for 2011 include:

Utilities Group

- Our return on investments made in the utilities was positively impacted by new and interim rates and tariffs implemented in five utility jurisdictions during 2010 and early 2011. Consequently, year-to-date revenues have been positively impacted for rates that were not in effect in the prior periods.

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

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Construction of gas-fired generation to serve Colorado Electric customers is continuing to progress and is on schedule to begin providing energy on or before January 1, 2012. The 180 MW generation project is expected to cost approximately $227 million, of which $222 million has been expended through September 30, 2011.

- On April 28, 2011, Colorado Electric filed a request with the CPUC for a revenue increase of $40.2 million to recover costs and a return associated with the 180 MW generation project and other utility infrastructure assets and expenses, including PPA costs associated with the 200 MW Colorado IPP generation facility. The proposed rate increase would go into effect on January 1, 2012 to coincide with the expiration of the PPA with PSCo. Colorado Electric's Rebuttal Testimony was filed on October 14, 2011 and a hearing on the rate case with the CPUC began on November 1, 2011.

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

- On March 14, 2011, Colorado Electric filed a request for a CPCN to construct a third utility-owned 88 MW natural gas-fired turbine with an approximate cost of $102.0 million, excluding transmission. This CPCN request was filed in accordance with a December 2010 CPUC order. This order approved the retirement of the W.N. Clark coal-fired power plant under the Colorado Clean Air-Clean Jobs Act and granted a presumption of need for a portion of a third turbine. An initial settlement with interveners was reached and a settlement hearing occurred on October 25, 2011. Under the proposed settlement, Colorado Electric will construct the plant and own 42 MW and will sell the remaining 46 MW to a buyer who will provide a seven-year capacity purchase agreement. The capacity purchase agreement would require Colorado Electric to purchase the 46 MW ownership interest after contract expiration. An initial decision is expected by December 1, 2011.

- On November 1, 2011, Cheyenne Light filed a motion to rescind its filing for a certificate of public convenience and necessity with the WPSC to construct and operate a $158 million, 120 MW electric generation facility. This original filing was replaced with a new joint request filed on November 1, 2011 by Cheyenne Light and Black Hills Power with the WPSC for a certificate of public convenience and necessity to construct and operate a new $237 million natural gas-fired electric generation facility and related gas and electric transmission in Cheyenne, Wyo. The proposed facility will include construction of one simple-cycle, 37 MW combustion turbine that will be wholly owned by Cheyenne Light and one combined-cycle, 95 MW unit that will be jointly owned by Cheyenne Light and Black Hills Power. Cheyenne Light will own 40 MW and Black Hills Power will own 55 MW of the combined cycle unit.

- On June 13, 2011, the SDPUC dismissed Black Hills Power's request for declaratory ruling to confirm that a proposed 20 MW wind farm site near Belle Fourche, SD is reasonable and cost effective.

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

Non-regulated Energy Group

- Construction of gas-fired generation by Colorado IPP to serve a 20-year PPA with Colorado Electric is continuing to progress and is on schedule to begin providing energy on January 1, 2012. The 200 MW project is expected to cost approximately $260 million, of which $250 million has been expended through September 30, 2011.

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

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Corporate

- We recognized a non-cash unrealized mark-to-market loss related to certain interest rate swaps of $40.6 million for the nine months ended September 30, 2011 compared to a $41.7 million unrealized mark-to-market loss on these swaps for the same period in 2010.

- On November 1, 2011, the Equity Forward Agreements were settled by issuing 4,413,519 shares of Black Hills Corporation common stock in return for net cash proceeds of approximately $120 million.

- In September 2011, we extended our $100 million term loan under the existing terms for two-years.

- In June 2011, we entered into a $150 million one year, unsecured, single draw, term loan. The cost of borrowing under this term loan is based on a spread of 125 basis points over LIBOR. The proceeds were used to pay down a portion of our Revolving Credit Facility.

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,	
	2011	2010	2011	2010
	(in thousands)			
Revenue — electric	$149,664	$138,122	$417,512	$399,298
Revenue — gas	4,052	3,523	24,014	27,421
Total revenue	153,716	141,645	441,526	426,719
Fuel and purchased power — electric	71,387	67,104	203,319	205,409
Purchased gas	1,703	1,157	13,583	16,929
Total fuel and purchased power	73,090	68,261	216,902	222,338
Gross margin — electric	78,277	71,018	214,193	193,889
Gross margin — gas	2,349	2,366	10,431	10,492
Total gross margin	80,626	73,384	224,624	204,381
Operations and maintenance	34,837	33,428	106,107	102,152
Gain on sale of operating assets	(768)	(6,238)	(768)	(6,238)
Depreciation and amortization	13,221	12,481	39,051	35,567
Total operating expenses	47,290	39,671	144,390	131,481
Operating income	33,336	33,713	80,234	72,900

Interest expense, net	(9,729)	(10,573)	(29,780)	(27,275)
Other income (expense), net	200	400	556	2,840
Income tax expense	(8,017)	(5,003)	(16,357)	(12,880)
Net income	$15,790	$18,537	$34,653	$35,585

The following tables summarize revenue, quantities generated and purchased, quantities sold, degree days and plant availability for our Electric Utilities segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Revenue - electric (in thousands)	2011	2010	2011	2010
Residential:				
Black Hills Power	$15,034	$13,492	$44,977	$39,517
Cheyenne Light	7,826	7,235	22,923	21,945
Colorado Electric	24,462	21,674	64,053	57,697
Total Residential	47,322	42,401	131,953	119,159
Commercial:				
Black Hills Power	19,889	18,529	54,962	49,172
Cheyenne Light	14,802	14,379	40,840	40,251
Colorado Electric	19,784	17,833	54,742	49,528
Total Commercial	54,475	50,741	150,544	138,951
Industrial:				
Black Hills Power	6,716	5,402	18,944	16,243
Cheyenne Light	3,017	2,156	8,573	7,568
Colorado Electric	8,086	7,606	24,520	21,391
Total Industrial	17,819	15,164	52,037	45,202
Municipal:				
Black Hills Power	908	850	2,425	2,251
Cheyenne Light	475	419	1,321	887
Colorado Electric	3,442	3,130	9,564	7,688
Total Municipal	4,825	4,399	13,310	10,826
Contract Wholesale:				
Black Hills Power	4,519	4,758	13,509	18,554
Off-system Wholesale:				
Black Hills Power	9,158	9,695	23,553	26,950
Cheyenne Light	1,535	2,545	7,002	7,255
Colorado Electric [(a)]	—	506	—	10,742
Total Off-system Wholesale	10,693	12,746	30,555	44,947
Other:				
Black Hills Power	8,716	6,325	21,862	17,291
Cheyenne Light	649	773	1,905	2,474
Colorado Electric	646	815	1,837	1,894
Total Other	10,011	7,913	25,604	21,659
Total Revenue - electric	$149,664	$138,122	$417,512	$399,298

(a) In August 2010, Colorado Electric agreed with the CPUC to defer off-system operating income until a sharing mechanism is settled upon. As a result Colorado Electric deferred $2.0 million and $8.4 million in off-system revenue during the three and nine months ended September 30, 2011, respectively, and $2.1 million commencing August 6, 2010 for the three and nine months ended September 30, 2010.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Quantities Generated and Purchased (in MWh)	2011	2010	2011	2010
Generated —				
Coal-fired:				
Black Hills Power	463,032	525,000	1,286,876	1,514,831
Cheyenne Light	170,643	196,079	511,209	553,978
Colorado Electric	74,470	66,951	202,381	193,195
Total Coal	708,145	788,030	2,000,466	2,262,004
Gas and Oil-fired:				
Black Hills Power	11,424	11,780	13,595	15,724
Cheyenne Light	—	—	—	—
Colorado Electric	2,748	1,061	2,778	1,154
Total Gas and Oil-fired	14,172	12,841	16,373	16,878
Total Generated:				
Black Hills Power	474,456	536,780	1,300,471	1,530,555
Cheyenne Light	170,643	196,079	511,209	553,978
Colorado Electric	77,218	68,012	205,159	194,349
Total Generated	722,317	800,871	2,016,839	2,278,882
Purchased —				
Black Hills Power	409,174	314,924	1,186,004	1,035,124
Cheyenne Light	172,520	166,082	548,768	510,509
Colorado Electric	527,975	540,192	1,496,812	1,569,350
Total Purchased	1,109,669	1,021,198	3,231,584	3,114,983
Total Generated and Purchased:				
Black Hills Power	883,630	851,704	2,486,475	2,565,679
Cheyenne Light	343,163	362,161	1,059,977	1,064,487
Colorado Electric	605,193	608,204	1,701,971	1,763,699
Total Generated and Purchased	1,831,986	1,822,069	5,248,423	5,393,865

	Three Months Ended September 30,		Nine Months Ended September 30,	
Quantity Sold (in MWh)	2011	2010	2011	2010
Residential:				
Black Hills Power	132,571	122,123	414,654	410,561
Cheyenne Light	65,643	62,150	197,053	196,122
Colorado Electric	185,775	180,771	481,774	485,381
Total Residential	383,989	365,044	1,093,481	1,092,064
Commercial:				
Black Hills Power	198,774	195,634	544,660	544,935
Cheyenne Light	157,138	160,359	446,382	449,483
Colorado Electric	201,266	201,989	547,168	554,584
Total Commercial	557,178	557,982	1,538,210	1,549,002
Industrial:				
Black Hills Power	106,658	90,426	301,268	278,514
Cheyenne Light	44,857	32,943	128,327	117,373
Colorado Electric	90,895	95,795	265,992	265,789
Total Industrial	242,410	219,164	695,587	661,676
Municipal:				
Black Hills Power	9,917	9,008	25,958	24,811
Cheyenne Light	2,528	2,223	7,122	3,836
Colorado Electric	36,657	36,465	96,483	85,881
Total Municipal	49,102	47,696	129,563	114,528
Subtotal Retail Quantities Sold	1,232,679	1,189,886	3,456,841	3,417,270
Contract Wholesale:				
Black Hills Power [(a)]	84,346	83,013	256,558	371,736
Off-system Wholesale:				
Black Hills Power	299,511	309,297	819,753	839,408
Cheyenne Light	47,615	86,675	211,541	234,937
Colorado Electric [(b)]	48,643	59,453	222,091	292,741
Total Off-system Wholesale	395,769	455,425	1,253,385	1,367,086
Total Quantity Sold:				
Black Hills Power	831,777	809,501	2,362,851	2,469,965
Cheyenne Light	317,781	344,350	990,425	1,001,751
Colorado Electric	563,236	574,473	1,613,508	1,684,376
Total Quantity Sold	1,712,794	1,728,324	4,966,784	5,156,092
Losses and Company Use:				
Black Hills Power	51,853	42,203	123,624	95,714
Cheyenne Light	25,382	17,811	69,552	62,736
Colorado Electric	41,957	33,731	88,463	79,323
Total Losses and Company Use	119,192	93,745	281,639	237,773

Total Energy	1,831,986	1,822,069	5,248,423	5,393,865

(a) MWh for the nine months ended September 30, 2011 decreased due to the termination of a wholesale contract with a previous wholesale power customer that acquired ownership interest in the Wygen III facility.
(b) In August 2010, Colorado Electric agreed with the CPUC to defer off-system operating income until a sharing mechanism is determined. In accordance with this agreement, operating income for off-system MWh sold at Colorado Electric totaling $0.2 million and $0.4 million has been deferred for the three and nine months ended September 30, 2011 and $0.5 million for the three and nine months ending September 30, 2010, respectively. Operating income of $1.3 million has been deferred since the agreement was approved in August 2010.

Degree Days	Three Months Ended September 30, 2011		2010	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Actual —				
Black Hills Power	153	(33)%	188	(17)%
Cheyenne Light	197	(40)%	159	(51)%
Colorado Electric	46	(50)%	11	(88)%
Cooling Degree Days:				
Actual —				
Black Hills Power	620	26%	456	(8)%
Cheyenne Light	399	73%	310	34%
Colorado Electric	958	36%	793	13%

Degree Days	Nine Months Ended September 30, 2011		2010	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Actual —				
Black Hills Power	5,050	(30)%	4,484	(3)%
Cheyenne Light	4,674	(37)%	4,577	(3)%
Colorado Electric	3,465	(38)%	3,435	2%
Cooling Degree Days:				
Actual —				
Black Hills Power	676	13%	521	(12)%
Cheyenne Light	429	57%	345	26%
Colorado Electric	1,252	36%	1,073	17%

Electric Utilities Power Plant Availability	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Coal-fired plants	95.1%	95.9%	91.6% (a)	93.2%
Other plants	98.6%	98.5%	95.7%	98.5%
Total availability	96.4%	96.8%	93.1%	95.1%

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

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 for these natural gas distribution operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenue (in thousands):				
Residential	$2,561	$2,359	$14,592	$16,642
Commercial	946	736	6,492	7,791
Industrial	370	257	2,226	2,378
Other	175	171	704	610
Total Revenue	$4,052	$3,523	$24,014	$27,421
Gross Margin (in thousands):				
Residential	$1,739	$1,779	$7,459	$7,329
Commercial	387	372	2,293	2,341
Industrial	63	49	338	276
Other	160	166	341	546
Total Gross Margin	$2,349	$2,366	$10,431	$10,492
Volumes Sold (Dth):				
Residential	179,602	173,430	1,745,313	1,868,609
Commercial	122,138	111,643	1,048,404	1,104,484
Industrial	66,962	76,056	463,618	453,601
Total Volumes Sold	368,702	361,129	3,257,335	3,426,694

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Electric Utilities segment was $15.8 million for the three months ended September 30, 2011 compared to $18.5 million for the three months ended September 30, 2010 as a result of:

Gross margin increased $7.2 million primarily due to $2.5 million from rate adjustments that include a return on significant capital investments, $1.7 million from an increase in retail volumes, $2.0 million from transmission cost adjustments and $0.6 million from the impact of a new Environmental Improvement Cost Recovery rider which went into effect on June 1, 2011, partially offset by lower off-system sales margins of $0.3 million.

Operations and maintenance increased $1.4 million primarily due to increased allocation of corporate costs resulting from higher asset deployment at the Electric Utilities and the impact of a decrease in property taxes in 2010 due to the settlement of appeals that resulted in an adjustment for prior years of $0.4 million.

Gain on sale of operating assets in 2011 relates to the sale of assets to a related party and was eliminated in the consolidation. The gain on sale in 2010 represents the sale of a 23% ownership interest in the Wygen III generating facility.

Depreciation and amortization increased $0.7 million primarily due to a higher asset bases.

Interest expense, net decreased $0.8 million primarily due to higher AFUDC-borrowed associated with recent capital investments at Colorado Electric.

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

Income tax expense: The effective tax rate increased from the same period in the prior year primarily due to a $2.2 million prior year tax benefit for a repairs deduction taken for tax purposes and the flow-through treatment of such tax benefit resulting from a rate case settlement in 2010.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net income for the Electric Utilities segment was $34.7 million for the nine months ended September 30, 2011 compared to $35.6 million for the nine months ended September 30, 2010 as a result of:

Gross margin increased $20.2 million primarily due to $17.1 million from rate adjustments that include a return on significant capital investments, $5.3 million from transmission cost adjustments and $0.6 million from the impact of a new Environmental Improvement Cost Recovery rider which went into effect on June 1, 2011, partially offset by lower off-system sales margins of $2.6 million.

Operations and maintenance increased $4.0 million primarily due to an increase in labor and employee benefit costs, increased allocation of corporate costs, additional costs associated with Wygen III, which commenced commercial operation on April 1, 2010, and an impact from lower property taxes in 2010 due to the settlement of appeals which resulted in an adjustment for prior years of $0.4 million.

Gain on sale of operating assets in 2011 relates to the sale of assets to a related party and was eliminated in the consolidation. The gain on sale in 2010 represents the sale of a 23% ownership interest in the Wygen III generating facility.

Depreciation and amortization increased $3.5 million primarily due to a higher asset base including additional depreciation associated with Wygen III, which commenced commercial operations on April 1, 2010.

Interest expense, net increased $2.5 million primarily due to higher debt balances, partially offset by an increase in AFUDC-borrowed and interest income.

Other income (expense), net decreased $2.3 million primarily due to decreased AFUDC-equity resulting from with the commencement of commercial operation of our Wygen III facility.

Income tax expense: The effective tax rate increased from the same period in the prior year primarily due to a $2.2 million prior year tax benefit for a repairs deduction taken for tax purposes and the flow-through treatment of such tax benefit resulting from a rate case settlement in 2010.

Gas Utilities

	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
	(in thousands)			
Revenue:				
Natural gas — regulated	$65,887	$64,109	$382,517	$379,291
Other — non-regulated services	6,764	8,214	20,322	23,317
Total revenue	72,651	72,323	402,839	402,608
Cost of sales:				
Natural gas — regulated	29,693	27,804	229,152	230,555
Other — non-regulated services	3,480	5,729	10,260	13,501
Total cost of sales	33,173	33,533	239,412	244,056
Gross margin	39,478	38,790	163,427	158,552
Operations and maintenance	28,317	26,957	91,126	93,406
Gain on sale of operating assets	—	—	—	(2,683)
Depreciation and amortization	6,064	5,711	18,032	19,530
Total operating expenses	34,381	32,668	109,158	110,253
Operating income (loss)	5,097	6,122	54,269	48,299
Interest expense, net	(6,329)	(6,983)	(19,640)	(19,992)
Other income (expense), net	27	(7)	176	42
Income tax benefit (expense)	1,777	273	(10,530)	(10,332)
Net income (loss)	$572	$(595)	$24,275	$18,017

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

Revenue (in thousands)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Residential:				
Colorado	$5,493	$5,104	$39,228	$38,553
Nebraska	12,736	13,134	91,798	86,904
Iowa	11,235	11,239	77,259	74,814
Kansas	7,928	7,711	46,449	51,640
Total Residential	37,392	37,188	254,734	251,911
Commercial:				
Colorado	1,352	1,156	8,167	8,384
Nebraska	3,520	3,441	29,823	30,101
Iowa	4,397	4,881	33,082	33,894
Kansas	2,076	2,048	14,316	16,352
Total Commercial	11,345	11,526	85,388	88,731
Industrial:				
Colorado	1,174	920	1,872	1,213
Nebraska	194	441	530	2,582
Iowa	334	183	1,478	1,366
Kansas	10,437	8,831	18,406	13,166
Total Industrial	12,139	10,375	22,286	18,327
Transportation:				
Colorado	84	95	591	546
Nebraska	1,626	1,735	8,057	8,308
Iowa	687	746	2,839	2,704
Kansas	1,311	1,222	4,503	4,206
Total Transportation	3,708	3,798	15,990	15,764
Other:				
Colorado	22	22	78	78
Nebraska	432	396	1,551	1,492
Iowa	122	95	441	677
Kansas	727	709	2,049	2,311
Total Other	1,303	1,222	4,119	4,558
Total Regulated	65,887	64,109	382,517	379,291
Other - non-regulated services	6,764	8,214	20,322	23,317
Total Revenue	$72,651	$72,323	$402,839	$402,608

Gross Margin (in thousands)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Residential:				
Colorado	$2,695	$2,710	$12,575	$13,265
Nebraska	8,480	9,019	37,861	35,069
Iowa	8,291	8,053	34,885	32,128
Kansas	5,465	5,385	21,663	21,677
Total Residential	24,931	25,167	106,984	102,139
Commercial:				
Colorado	460	462	2,105	2,372
Nebraska	1,486	1,542	8,462	8,720
Iowa	1,862	1,895	8,458	8,524
Kansas	1,006	991	4,731	4,771
Total Commercial	4,814	4,890	23,756	24,387
Industrial:				
Colorado	239	218	402	309
Nebraska	48	60	139	294
Iowa	38	27	176	145
Kansas	1,144	976	2,136	1,639
Total Industrial	1,469	1,281	2,853	2,387
Transportation:				
Colorado	84	95	590	546
Nebraska	1,626	1,735	8,057	8,308
Iowa	687	746	2,839	2,704
Kansas	1,311	1,222	4,503	4,219
Total Transportation	3,708	3,798	15,989	15,777
Other:				
Colorado	22	22	78	78
Nebraska	433	396	1,552	1,491
Iowa	122	95	441	678
Kansas	695	656	1,712	1,799
Total Other	1,272	1,169	3,783	4,046
Total Regulated	36,194	36,305	153,365	148,736
Other - non-regulated services	3,284	2,485	10,062	9,816
Total Gross Margin	$39,478	$38,790	$163,427	$158,552

Volumes Sold (in Dth)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Residential:				
Colorado	450,778	415,476	4,298,162	4,386,492
Nebraska	764,676	795,150	8,607,301	8,515,902
Iowa	564,426	611,373	7,485,204	7,205,381
Kansas	461,169	430,282	4,710,725	4,835,615
Total Residential	2,241,049	2,252,281	25,101,392	24,943,390
Commercial:				
Colorado	145,413	121,682	980,931	1,046,490
Nebraska	373,386	378,760	3,465,363	3,576,684
Iowa	486,758	568,192	4,375,492	4,275,759
Kansas	203,109	198,604	1,830,720	1,887,456
Total Commercial	1,208,666	1,267,238	10,652,506	10,786,389
Industrial:				
Colorado	202,956	182,467	318,278	232,123
Nebraska	30,816	87,531	67,010	425,171
Iowa	56,401	29,875	234,864	207,376
Kansas	2,010,001	1,677,072	3,518,599	2,494,629
Total Industrial	2,300,174	1,976,945	4,138,751	3,359,299
Transportation:				
Colorado	75,828	88,106	604,493	563,325
Nebraska	5,910,136	5,782,468	18,546,617	19,331,381
Iowa	4,068,243	3,802,931	13,647,342	13,059,843
Kansas	4,331,612	3,982,029	11,712,421	11,284,332
Total Transportation	14,385,819	13,655,534	44,510,873	44,238,881
Other:				
Colorado	—	—	—	—
Nebraska	—	3,315	—	4,464
Iowa	—	7,250	—	59,779
Kansas	4,086	2	66,152	70,855
Total Other	4,086	10,567	66,152	135,098
Total Volumes Sold	20,139,794	19,162,565	84,469,674	83,463,057

Heating Degree Days:	Three Months Ended September 30, 2011 Actual	Variance From Normal	Nine Months Ended September 30, 2011 Actual	Variance From Normal
Colorado	116	(38)%	3,717	(7)%
Nebraska	157	49%	4,023	4%
Iowa	235	38%	4,780	3%
Kansas*	54	74%	3,085	1%
Combined Gas Utilities Heating Degree Days	152	36%	4,024	1%

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

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

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

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Gas Utilities segment was $0.6 million for the three months ended September 30, 2011 compared to Net loss of $0.6 million for the three months ended September 30, 2010 as a result of:

Gross margin increased $0.7 million primarily due to increased industrial volumes prompted by increased irrigation from dryer weather conditions compared to the same period in the prior year and an increase in margins primarily from the non-regulated business activities.

Operations and maintenance increased $1.4 million primarily due to an increase in employee compensation and benefit costs .

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

Interest expense, net decreased $0.7 million primarily due to increased interest income on intercompany lending.

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

Income tax benefit (expense): The effective tax rate for the three months ended September 30, 2011 was favorably impacted by a 2010 tax return true-up adjustment in 2011 primarily related to flow-through treatment of certain property-related temporary differences.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net income for the Gas Utilities segment was $24.3 million for the nine months ended September 30, 2011 compared to Net income of $18.0 million for the nine months ended September 30, 2010 as a result of:

Gross margin increased $4.9 million primarily due to rate adjustments and favorable weather than in the same period in the prior year.

Operations and maintenance decreased $2.3 million primarily due to lower allocation of corporate costs partially offset by higher compensation and benefit costs.

Gain on sale of operating assets represents assets sold in 2010 by Nebraska Gas to the City of Omaha, Nebraska, after a portion of Nebraska Gas' service territory was annexed by the City.

Depreciation and amortization decreased $1.5 million primarily due to a decrease in depreciation expense resulting from fully depreciated assets and a shift in corporate allocations as a result of higher asset deployment at the Electric Utilities.

Interest expense, net was comparable to the same period in the prior year.

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

Income tax expense: The effective tax rate for the nine months ended September 30, 2011 was favorably impacted by a 2010 tax return true-up adjustment in 2011 primarily related to flow-through treatment of certain property-related temporary differences.

Regulatory Matters — Utilities Group

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

							Approved Capital Structure	
	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved	Return on Equity	Equity	Debt
Nebraska Gas (1)	Gas	12/2009	9/2010	$12.1	$8.3	10.1 %	52.0 %	48.0 %
Iowa Gas (2)	Gas	6/2010	6/2010	$4.7	$3.4	Global Settlement	Global Settlement	Global Settlement
Black Hills Power (3)	Electric	9/2009	4/2010	$32.0	$15.2	Global Settlement	Global Settlement	Global Settlement
Black Hills Power (3)	Electric	10/2009	6/2010	$3.8	$3.1	10.5 %	52.0 %	48.0 %
Black Hills Power (4)	Electric	1/2011	6/2011	Not Applicable	$3.1	Not Applicable	Not Applicable	Not Applicable
Colorado Electric (5)	Electric	1/2010	8/2010	$22.9	$17.9	10.5 %	52.0 %	48.0 %
Colorado Electric (6)	Electric	4/2011	Pending	$40.2	Pending	Pending	Pending	Pending

(1)

In December 2009, Nebraska Gas filed a rate case with the NPSC and interim rates went into effect on March 1, 2010. In August 2010, NPSC issued a decision approving an annual revenue increase of approximately $8.3 million effective on September 1, 2010. A refund to customers for the difference between interim rates and approved rates was completed in the first quarter of 2011. The Nebraska Public Advocate filed an initial appeal which was denied. The Public Advocate subsequently filed a notice of appeal with the Court of Appeals.

(2) In June 2010, Iowa Gas filed a request with the IUB for a $4.7 million, or 2.9%, revenue increase to recover the cost of capital investments made in our gas distribution system and other expense increases incurred since December 2008. Interim rates, subject to refund, equal to a $2.6 million increase, or 1.6%, in revenues went into effect on June 18, 2010. In August 2010, we reached a settlement with the OCA for a revenue increase of $3.4 million and hearings on the settlement were held in October 2010. Approval from the IUB of a modified settlement for a revenue increase of $3.4 million was received in February 2011.

(3) This rate case was previously described in our 2010 Annual Report on Form 10-K.

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

(5) On January 5, 2010, Colorado Electric filed a rate case with CPUC requesting an electric revenue increase primarily related to the recovery of rising costs from electricity supply contracts, as well as recovery for investment in equipment and electricity distribution facilities necessary to maintain and strengthen the reliability of the electric delivery system. Colorado Electric requested a $22.9 million, or approximately 12.8%, increase in annual revenue. In August 2010, the CPUC approved a settlement agreement for $17.9 million in annual revenue with a return on equity of 10.5% and a capital structure of 52% equity and 48% debt. New rates were effective August 6, 2010.

Included in the rate case order was a provision that off-system sales margins be shared with customers commencing August 6, 2010. The percentage of margin to be shared with the customers was not resolved at the time of the rate case settlement. The CPUC has therefore required that the off-system operating income earned beginning August 6, 2010 be deferred on the balance sheet until settlement of the sharing mechanism. Since August 2010, $1.3 million in off-system operating income has been deferred. The determination for a sharing mechanism is now being considered as part of the rate case filed with the CPUC by Colorado Electric discussed below.

(6) On April 28, 2011, Colorado Electric filed a request with the CPUC for an annual revenue increase of $40.2 million, or 18.8%, to recover costs and a return on capital associated with the 180 MW generating facilities currently under construction, associated infrastructure assets and other utility expenses, including the PPA with Colorado IPP. The facilities are expected to be in operation by the end of 2011. This rate request was amended by Colorado Electric's Rebuttal Testimony filed on October 14, 2011. A hearing on the rate case with the CPUC began November 1, 2011.

Non-regulated Energy Group

We report four segments within our Non-regulated Energy Group: Oil and Gas, Coal Mining, Energy Marketing and Power Generation. An analysis of results from our Non-regulated Energy Group's operating segments follows:

Oil and Gas

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Revenue	$19,163	$19,354	$55,907	$57,755
Operations and maintenance	9,573	9,731	30,327	29,964
Depreciation, depletion and amortization	7,714	7,326	22,637	20,279
Total operating expenses	17,287	17,057	52,964	50,243
Operating income (loss)	1,876	2,297	2,943	7,512
Interest expense	(1,460)	(1,565)	(4,232)	(3,738)
Other income (expense), net	54	129	(43)	671

Income tax (expense) benefit	(229)	(25)	779	(1,040)
Net income (loss)	$241	$836	$(553)	$3,405

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Production:				
Bbls of oil sold	98,950	99,950	303,401	268,768
Mcf of natural gas sold	2,289,137	2,285,016	6,671,176	6,793,866
Mcf equivalent sales	2,882,837	2,884,716	8,491,582	8,406,474

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Average price received: (a)				
Gas/Mcf (b)	$4.24	$4.64	$4.39	$5.12
Oil/Bbl	$82.76	$80.87	$76.25	$81.70
Depletion expense/Mcfe	$2.38	$2.18	$2.38	$2.11

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

The following is a summary of certain average operating expenses per Mcfe:

	Three Months Ended September 30, 2011				Three Months Ended September 30, 2010			
	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.06	$0.25	$0.52	$1.83	$1.21	$0.30	$0.48	$1.99
Piceance	0.80	0.63	0.28	1.71	1.06	0.53	0.23	1.82
Powder River	1.20	—	1.26	2.46	1.14	—	0.92	2.06
Williston	1.01	—	1.74	2.75	1.19	—	1.16	2.35
All other properties	0.62	—	0.38	1.00	0.94	—	0.44	1.38
Total weighted average	$0.99	$0.18	$0.72	$1.89	$1.13	$0.19	$0.59	$1.91

	Nine Months Ended September 30, 2011				Nine Months Ended September 30, 2010			
	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.17	$0.35	$0.54	$2.06	$1.31	$0.32	$0.58	$2.21
Piceance	0.77	0.73	0.06	1.56	0.66	0.65	0.29	1.60
Powder River	1.31	—	1.31	2.62	1.16	—	1.02	2.18
Williston	0.59	—	1.58	2.17	1.33	—	1.21	2.54
All other properties	1.17	—	0.26	1.43	1.03	—	0.30	1.33
Total weighted average	$1.11	$0.23	$0.70	$2.04	$1.16	$0.21	$0.62	$1.99

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Oil and Gas segment was $0.2 million for the three months ended September 30, 2011 compared to Net income of $0.8 million for the same period in 2010 as a result of:

Revenue was comparable to the same period in the prior year with offsetting changes of a 2% higher average hedged oil price received and 1% higher natural gas volumes, exclusive of gas liquids, partially offset by a 1% decrease in oil volumes and a 9% decrease in average hedged price received for natural gas. Oil volumes declined primarily due to natural production declines from producing properties partially offset by production gains in our ongoing Bakken drilling program.

Operations and maintenance costs were comparable to the same period in the prior year.

Depreciation, depletion and amortization increased $0.4 million primarily due to a higher depletion rate, resulting primarily from higher finding and development costs for our Bakken oil drilling program.

Interest expense, net was comparable to the same period in the prior year.

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

Income tax (expense) benefit: The effective tax rate in 2011 was negatively impacted primarily by the true-up of percentage depletion related to the filing of the 2010 tax return while 2010 was positively impacted by a $0.4 million re-measurement of a previously recorded uncertain tax position due to a settlement agreement with the IRS.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net loss for the Oil and Gas segment was $0.6 million for the nine months ended September 30, 2011 compared to Net income of $3.4 million for the same period in 2010 as a result of:

Revenue decreased $1.8 million due to a 14% decrease in the average hedged price received for natural gas and a 7% decrease in the average hedged price received for oil, as well as a 2% decline in gas volumes, exclusive of gas liquids, partially offset by a 13% increase in crude oil volumes. The average crude oil price received was influenced by fixed price swaps previously entered into at prices significantly below current market prices. The increase in oil volumes was favorably impacted by volumes at new wells in our ongoing Bakken drilling program in North Dakota.

Operations and maintenance costs were comparable to the same period in the prior year.

Depreciation, depletion and amortization increased $2.4 million primarily due to a higher depletion rate, resulting primarily from higher finding and development costs on a per Mcfe basis for our Bakken oil drilling program.

Interest expense increased $0.5 million primarily due to inter-company interest allocations on inter-company borrowings.

Other income (expense), net decreased $0.7 million due to lower earnings from equity investments.

Income tax (expense) benefit: The effective tax rate in 2011 was positively impacted primarily by the tax benefit generated by percentage depletion while the effective tax rate for 2010 was positively impacted by a $0.4 million re-measurement of a previously recorded uncertain tax position prompted by a settlement agreement with the IRS.

Coal Mining

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Revenue	$17,835	$14,277	$48,870	$43,306
Operations and maintenance	14,171	10,750	41,754	30,041
Depreciation, depletion and amortization	5,151	3,342	14,364	9,553
Total operating expenses	19,322	14,092	56,118	39,594
Operating income (loss)	(1,487)	185	(7,248)	3,712
Interest income, net	972	1,086	2,868	2,191
Other income	532	510	1,650	1,593
Income tax benefit (expense)	538	(108)	1,606	(1,403)
Net income (loss)	$555	$1,673	$(1,124)	$6,093

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Tons of coal sold	1,550	1,489	4,155	4,340
Cubic yards of overburden moved	3,873	4,482	10,261	11,805

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Coal Mining segment was $0.6 million for the three months ended September 30, 2011 compared to Net income of $1.7 million for the same period in 2010, as a result of:

Revenue increased $3.6 million primarily due to a 20% increase in average sales price per ton and a 4% increase in coal volumes sold. The higher average sales price reflects the impact of price escalators and adjustments in certain of our sales contracts. Approximately 40% of our coal production is sold under sales contracts that include adjustments to the sales price based on actual mining cost increases. Most of our remaining production is sold under contracts where the sales price may escalate based on published indices, which may not necessarily represent changes in actual mining costs.

Operations and maintenance increased $3.4 million which is reflective of longer haul distances and higher overburden stripping costs in the current phase of our mining. Additionally, we experienced higher costs associated with drilling and blasting, equipment maintenance, clay parting removal, fuel, staffing levels for our train load-out facility and weather conditions. As noted above, a portion of our production is sold under contracts that have price escalators based on published indices. These escalators have not kept up with actual mining cost increases, reducing coal mine operating income, and are expected to continue to negatively impact 2011 results. Previous periods also include the capitalization of certain costs associated with mine infrastructure, including our in-pit conveyor system that is used to transport coal to mine-mouth generation facilities.

Depreciation, depletion and amortization increased $1.8 million primarily due to higher depreciation on reclamation related costs and mining equipment.

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

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

Income tax benefit (expense): The effective tax rate for the three months ended September 30, 2011 was favorably impacted by a true-up of percentage depletion related to the filing of the 2010 tax return.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net loss for the Coal Mining segment was $1.1 million for the nine months ended September 30, 2011 compared to Net income of $6.1 million for the same period in 2010 as a result of:

Revenue increased $5.6 million primarily due to an 18% increase in average sales price received per ton, partially offset by 4% lower coal volumes sold. The higher average sales price reflects the impact of price escalators and adjustments in certain of our sales contracts. Approximately 40% of our coal production is sold under sales contracts that include adjustments to the sales price based on actual mining cost increases. Most of our remaining production is sold under contracts where the sales price may escalate based on published indices, which may not necessarily represent changes in actual mining costs.

Operations and maintenance increased $11.7 million which is reflective of longer haul distances and higher overburden stripping costs in the current phase of our mining. Additionally, we experienced higher costs associated with drilling and blasting, equipment maintenance, clay parting removal, fuel, and staffing levels for our train load-out facility. As noted above, over half of our production is sold under contracts that have price escalators based on published indices. These escalators have not kept up with actual mining cost increases, reducing coal mine operating income, and are expected to continue to negatively impact 2011 results. Previous periods also include the capitalization of certain costs associated with mine infrastructure, including our in-pit conveyor system that is used to transport coal to mine-mouth generation facilities.

Depreciation, depletion and amortization increased $4.8 million primarily related to higher depreciation on reclamation related costs and mining equipment.

Interest income, net increased $0.7 million primarily due to increased inter-company debt balances.

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

Income tax benefit (expense): The effective income tax rate for 2011 was favorably impacted by a true-up of percentage depletion related to the filing of the 2010 tax return.

Energy Marketing

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Gross margin —				
Realized gross margin	$25,481	$(704)	$31,931	$13,994
Unrealized gross margin	(18,543)	9,677	(10,052)	13,646
Total gross margin	6,938	8,973	21,879	27,640
Operating expenses	5,702	6,349	18,033	17,807
Depreciation and amortization	159	128	442	387
Total operating expenses	5,861	6,477	18,475	18,194
Operating income	1,077	2,496	3,404	9,446
Interest expense, net	(430)	(380)	(1,087)	(1,942)

Other income (expense), net	(6)	(1)	(4)	152
Income tax (expense) benefit	(368)	(745)	(986)	(2,766)
Net income (loss)	$273	$1,370	$1,327	$4,890

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Gross margin by commodity (in thousands):

Three Months Ended	Natural Gas	Crude Oil	Coal [a]	Power [a]	Environmental [a]	Total
September 30, 2011						
Realized	$16,752	$11,225	$(1,200)	$(1,292)	$(4)	$25,481
Unrealized	(12,138)	(2,083)	(2,005)	(2,174)	(143)	(18,543)
Total	$4,614	$9,142	$(3,205)	$(3,466)	$(147)	$6,938
September 30, 2010						
Realized	$(3,897)	$2,952	$241	$—	$—	$(704)
Unrealized	6,016	(1,268)	4,929	—	—	9,677
Total	$2,119	$1,684	$5,170	$—	$—	$8,973

Nine Months Ended	Natural Gas	Crude Oil	Coal [a]	Power [a]	Environmental [a]	Total
September 30, 2011						
Realized	$20,662	$13,760	$406	$(2,893)	$(4)	$31,931
Unrealized	(10,876)	(2,207)	1,358	1,697	(24)	(10,052)
Total	$9,786	$11,553	$1,764	$(1,196)	$(28)	$21,879
September 30, 2010						
Realized	$8,670	$5,526	$(202)	$—	$—	$13,994
Unrealized	5,056	(504)	9,094	—	—	13,646
Total	$13,726	$5,022	$8,892	$—	$—	$27,640

(a) Coal marketing activity began June 1, 2010, Power marketing began late in the third quarter of 2010, and Environmental marketing began late in the third quarter of 2010 with no activity until second quarter of 2011.

Following is a summary of average daily quantities marketed:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Natural gas physical sales — MMBtus	1,493,357	1,666,674	1,581,945	1,589,261
Crude oil physical sales — Bbls	26,628	19,410	23,729	17,947
Coal physical sales — Tons [a]	34,352	28,549	34,851	28,407
Power - MWh [a]	593	—	262	—

(a) Coal marketing activity began June 1, 2010 and Power marketing began late in the third quarter of 2010.

Natural gas, crude oil and coal inventory held by Energy Marketing primarily consists of gas held in storage and crude oil inventory held to meet pipeline line pack requirements. Natural gas storage is held in inventory to capture the price differential between the time at which it was purchased and a subsequent sales date. Crude oil line pack is held to satisfy requirements by pipelines on which the company transports crude oil. Quantities held were as follows:

	As of September 30, 2011	As of December 31, 2010	As of September 30, 2010
Natural gas (MMBtu)	7,930,831	14,922,353	16,262,328
Crude oil (Bbl)	194,141	198,052	156,000
Coal (Ton)	59,859	1,529	—
Renewable Energy Credits (MWh)	31,280	—	—

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Energy Marketing segment was $0.3 million for the three months ended September 30, 2011 compared to Net income of $1.4 million for the same period in 2010 as a result of:

Gross margin decreased $2.0 million primarily due to lower unrealized marketing margins of $28.2 million partially offset by increased realized margins of $26.2 million. The decrease in unrealized margins primarily reflects lower natural gas margins, lower margins from the coal portfolio and losses from the power marketing portfolio. These decreases in unrealized marketing margins were partially offset by higher realized natural gas and crude oil marketing margins.

Operating expenses decreased $0.6 million primarily due to a lower provision for compensation related to decreased margins, partially offset by higher compensation and benefit expenses relating to additional staff marketing new commodities and new geographic regions.

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

Interest expense, net was comparable to the same period in the prior year.

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

Income tax (expense) benefit: The effective income tax rate for the three months ended September 30, 2011 increased primarily due to permanent differences related to the filing of the 2010 tax return.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net income for the Energy Marketing segment was $1.3 million for the nine months ended September 30, 2011 compared to a Net income of $4.9 million for the same period in 2010 as a result of:

Gross margin decreased $5.8 million primarily driven by lower unrealized marketing margins of $23.7 million partially offset by an increase of $17.9 million in realized marketing margins. The decrease in unrealized margins primarily reflects lower natural gas and coal margins. Realized marketing margins include realized gains from natural gas and crude oil, partially offset by losses from power marketing.

Operating expenses were comparable to the same period in the prior year.

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

Interest expense, net decreased $0.9 million primarily due to lower inter-company borrowings.

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

Income tax (expense) benefit: The effective income tax rate for the nine months ended September 30, 2011 was comparable to the same period in the prior year.

Power Generation

	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
	(in thousands)			
Revenue	$8,100	$7,855	$23,500	$22,602
Operating, general and administrative costs	4,602	3,724	12,881	12,289
Depreciation and amortization	1,064	1,048	3,168	3,374
Gain on sale of operating asset	—	—	—	—
Total operating expense (income)	5,666	4,772	16,049	15,663
Operating income	2,434	3,083	7,451	6,939
Interest expense, net	(1,835)	(2,194)	(5,461)	(6,177)
Other (expense) income	(5)	(266)	1,220	894
Income tax (expense) benefit	(257)	(48)	(1,139)	(417)
Net income (loss)	$337	$575	$2,071	$1,239

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

	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Contracted power plant fleet availability:				
Coal-fired plant	97.1%	96.9%	98.9%	98.6%
Natural gas-fired plants	100.0%	100.0%	100.0%	100.0%
Total availability	98.1%	98.2%	99.3%	99.2%

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In January 2011, we sold our ownership interests in the partnerships which own the Idaho facilities.

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Power Generation segment was $0.3 million for the three months ended September 30, 2011 compared to Net income of $0.6 million for the same period in 2010 as a result of:

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

Operations and maintenance increased $0.9 million primarily due to higher maintenance costs at Black Hills Wyoming, higher transmission costs and additional costs incurred at Colorado IPP as construction progresses and employees prepare for operations of the facilities.

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

Interest expense, net was comparable to the same period in the prior year.

Other (expense) income decreased $0.3 million due to lower earnings from our partnership investments than in 2010.

Income tax (expense) benefit: The effective tax rate for the three months ended September 30, 2011 increased over the prior period due to unfavorable adjustments related to true-up of research and development credits.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net income for the Power Generation segment was $2.1 million for the nine months ended September 30, 2011 compared to Net income of $1.2 million for the same period in 2010 as a result of:

Revenue increased $0.9 million primarily due to increased sales from Wygen I, which incurred a forced outage and a major overhaul in the same period in the prior year.

Operations and maintenance increased $0.6 million primarily due to higher coal costs and higher costs associated with Colorado IPP as construction progresses and employees prepare for operations of the facilities.

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

Interest expense, net decreased $0.7 million due to the ability to capitalize additional interest at Colorado IPP and increased inter-company interest income at Black Hills Wyoming.

Other (expense) income increased due to the gain on sale of our ownership interest in the partnership that owned the Idaho generation facilities.

Income tax expense: The effective tax rate for the nine months ended September 30, 2011 increased over the prior period due to an unfavorable adjustment related to true-up of research and development credits.

Corporate

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net loss for Corporate was $27.9 million for the three months ended September 30, 2011 compared to Net loss of $10.1 million for the three months ended September 30, 2010 as a result of an unrealized before tax, non-cash mark-to-market loss on certain interest rate swaps for the quarter ended September 30, 2011 of approximately $38.2 million compared to a $13.7 million unrealized before tax, mark-to-market non-cash loss on these interest rate swaps in the prior year. Additionally, our income tax expense for the three months ended September 30, 2010 decreased $2.0 million due to a re-measurement of a previously recorded uncertain tax position prompted by a settlement agreement with the IRS relating primarily to depreciation method changes.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net loss for Corporate was $36.1 million compared to Net loss of $34.2 million as a result of an unrealized net before tax, mark-to-market loss on certain interest rate swaps for the nine months ended September 30, 2011 of approximately $40.6 million compared to a $41.7 million unrealized net before tax, mark-to-market non-cash loss on these interest rate swaps in the prior year. Additionally, our income tax expense in 2010 decreased $2.0 million due to a re-measurement of a previously recorded uncertain tax position prompted by a settlement agreement with the IRS relating primarily to depreciation method changes.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2010 Annual Report on Form 10-K filed with the SEC. For more information on our critical accounting policies, see Part II, Item 7 of our 2010 Annual Report on Form 10-K.

Liquidity and Capital Resources

Cash Flow Activities

The following table summarizes our cash flows for the nine months ended September 30, 2011 and 2010 (in thousands):

Cash provided by (used in):	2011	2010	Increase (Decrease)
Operating activities	$206,527	$125,761	$80,766
Investing activities	$(326,862)	$(253,755)	$(73,107)
Financing activities	$162,676	$74,068	$88,608

Year-to-Date 2011 Compared to Year-to-Date 2010

Operating Activities

Net cash provided by operating activities was $80.8 million higher for the nine months ended September 30, 2011 than the same period in 2010 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $26.2 million higher for the nine months ended September 30, 2011 than for the same period the prior year.

- Net outflows from operating assets and liabilities were $3.9 million for the nine months ended September 30, 2011, a decrease of $44.0 million from the same period in the prior year as a result of:

- Net outflows from working capital accounts were $31.3 million for the nine months ended September 30, 2011, compared to outflows of $52.9 million from the prior year. The change in net outflows relate to normal working capital changes including the effect of the seasonality of our gas utility operations as well as the following:
increased 2011 inflows of $53 million from changes in Materials, supplies and fuel primarily comprised of higher withdrawals of gas storage inventories by Energy Marketing of $45 million,
2011 inflow of $16 million as a result of a settlement reached with the IRS, and
Energy Marketing experienced higher outflows in the current period related to higher margin posted on marketing transactions of $41 million offset by a refund of cash collateral of $25 million posted by the Corporate segment for the de-designated hedges.
Inflows from changes in regulatory assets and regulatory liabilities, primarily related to collection of gas costs by our Gas Utilities.

- Cash contributions to the defined benefit pension plan were $11.0 million in 2011 compared to $30.0 million in 2010.

Investing Activities

Net cash used in investing activities was $73.1 million higher for the nine months ended September 30, 2011 than in the same period in 2010 reflecting higher capital additions. During 2011, cash outflows for property, plant and equipment additions totaled $328.5 million, including the on-going completion of construction of 180 MW of natural gas-fired electric generation at Colorado Electric and 200 MW of natural gas-fired electric generation at Black Hills Colorado IPP, and property maintenance capital and development drilling at the Oil and Gas segment.

Financing Activities

Net cash provided by financing activities was $88.6 million higher for the nine months ended September 30, 2011 than in the same period in 2010 primarily due to increased borrowings to finance our construction activities. During the nine months ended September 30, 2011, we refinanced a portion of the borrowings on our Revolving Credit Facility with a new $150 million corporate term loan which was used to pay down a portion of our Revolving Credit Facility, paid $6.2 million of long-term debt primarily related to required payments on the Black Hills Wyoming Project Financing, and paid $43.2 million of cash dividends on common stock.

Dividends

Dividends paid on our common stock totaled $43.2 million for the nine months ended September 30, 2011, or $1.095 per share. On October 27, 2011, our Board of Directors declared an additional quarterly dividend of $0.365 per share payable December 1, 2011, which is equivalent to an annual dividend rate of $1.46 per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects.

Financing Transactions and Short-Term Liquidity

Our principal sources of short-term liquidity are our Revolving Credit Facility and cash provided by operations. In addition to availability under our Revolving Credit Facility described below, as of September 30, 2011, we had approximately $75 million of cash unrestricted for operations.

Revolving Credit Facility

Our $500 million Revolving Credit Facility expiring April 14, 2013 can be used for the issuance of letters of credit, to fund working capital needs and for general corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 1.75%, 2.75% and 2.75%, respectively. The facility contains a commitment fee to be charged on the unused amount of the Facility. Based upon current credit ratings, the fee is 0.5%. The facility contains an accordion feature which allows us, with the consent of the administrative agent, to increase the capacity of the facility to $600 million.

At September 30, 2011, we had borrowings of $209 million and letters of credit outstanding of $42 million on our Revolving Credit Facility. Available capacity remaining on our Revolving Credit Facility was approximately $249 million at September 30, 2011.

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintenance of certain financial covenants including a minimum consolidated net worth and a recourse leverage ratio not to exceed 0.65 to 1.00.

Our consolidated net worth was $1.1 billion at September 30, 2011, which was approximately $216.7 million in excess of the net worth we were required to maintain under the Revolving Credit Facility. At September 30, 2011, our long-term debt ratio was 54.1%, our total debt leverage ratio (long-term debt and short-term debt) was 60.2%, and our recourse leverage ratio was approximately 61.3%. We were in compliance with these covenants as of September 30, 2011.

In addition to covenant violations, an event of default under the Revolving Credit Facility may be triggered by other events, such as a failure to make payments when due or a failure to make payments when due in respect of, or a failure to perform obligations relating to, other debt obligations of $35 million or more. Subject to applicable cure periods (none of which apply to a failure to timely pay indebtedness), an event of default would permit the lenders to restrict our ability to further access the credit facility for loans or new letters of credit, and could require both the immediate repayment of any outstanding principal and interest and the cash collateralization of outstanding letter of credit obligations.

Enserco Credit Facility

Enserco utilizes a two-year, $250 million committed credit facility expiring in May 2012 which includes an accordion feature which allows us, with the consent of the administrative agent, to increase commitments under the facility to $350 million. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. Margins for base rate borrowings are 1.75% and for Eurodollar borrowings are 2.50%. Enserco was in compliance with its debt covenants as of September 30, 2011.

At September 30, 2011, $132.6 million of letters of credit were issued under this facility and there were no cash borrowings outstanding.

Corporate Term Loans

In June 2011, we entered into a one-year $150 million unsecured, single draw, term loan with CoBank, the Bank of Nova Scotia and U.S. Bank due on June 24, 2012. The cost of borrowing under the loan is based on a spread of 125 basis points over LIBOR (1.63% at September 30, 2011). The covenants are substantially the same as those included in the Revolving Credit Facility. We were in compliance with these covenants as of September 30, 2011.

In December 2010, we entered into a one-year $100.0 million term loan with J.P. Morgan and Union Bank due in December 2011. On September 30, 2011, we extended that term loan for two-years under the existing terms to September 13, 2013. The cost of borrowing under this Term Loan was based on a spread of 137.5 basis points over LIBOR (1.625% at September 30, 2011). The covenants are substantially the same as those included in the Revolving Credit Facility. We were in compliance with these covenants as of September 30, 2011.

Dividend Restrictions

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders is derived from these cash flows. As a result of certain statutory limitations or regulatory or financing agreements, we could have restrictions on the amount of distributions allowed to be made by our subsidiaries.

- Our utility subsidiaries are generally limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of September 30, 2011, the restricted net assets at our Electric and Gas Utilities were approximately $164.3 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 the parent company. Enserco's restricted net assets at September 30, 2011 were $163.8 million compared to $93.0 million at December 31, 2010.

- As a covenant of the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted assets of $100 million. Black Hills Non-regulated Holdings is the parent of Black Hills Electric Generation, which is the parent of Black Hills Wyoming.

Future Financing Plans

We have substantial capital expenditures in 2011, which are primarily due to the construction of additional utility and IPP generation to serve Colorado Electric. Our capital requirements are expected to be financed through a combination of operating cash flows, borrowings on our Revolving Credit Facility, term loans and long-term financings. We settled the equity forward instrument executed in November 2010 on November 1, 2011. We may complete an additional long-term senior unsecured debt financing at the holding company level in 2012 and we are evaluating financing options including senior notes, first mortgage bonds, term loans, project financing and equity issuance. We intend to maintain a consolidated debt-to-capitalization level in the range of 50% to 55%; however, due to significant ongoing capital projects, we may exceed this level on a temporary basis. We anticipate that our existing credit capacity and available cash will be sufficient to fund our working capital needs and our maintenance capital requirements.

Equity Forward

In November 2010, we entered into a Forward Agreement with J.P. Morgan in connection with a public offering of 4,000,000 shares of Black Hills Corporation common stock. Under the Forward Agreement on November 10, 2010, we agreed to issue to J.P. Morgan 4,000,000 shares of our common stock at an initial forward price of $28.70875 per share. On December 7, 2010, the underwriters exercised the over-allotment option to purchase an additional 413,519 shares under the same terms as the original Forward Agreement (together with the Forward Agreement, the "Forward Agreements").

On November 1, 2011, the Equity Forward Agreements with J. P. Morgan were settled by issuing 4,413,519 shares of Black Hills Corporation common stock in return for approximately $120 million in net cash proceeds. The proceeds were used to pay down a portion of the Revolving Credit Facility.

Hedges and Derivatives

Interest Rate Swaps

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

We have interest rate swaps with a notional amount of $250 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on these swaps are recorded within the income statement. For the three and nine months ended September 30, 2011, respectively, we recorded $38.2 million and $40.6 million pre-tax unrealized mark-to-market non-cash losses on the swaps. The mark-to-market value on these swaps was a liability of $94.6 million at September 30, 2011. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A one basis point move in the interest rate curves over the term of the swaps would have a pre-tax impact of approximately $0.4 million. These swaps hedge interest rate exposure for periods to 2018 and 2028 and have amended mandatory early termination dates ranging from December 15, 2011 to December 29, 2011. We anticipate extending these agreements upon the mandatory early termination dates and have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly as they relate to our planned capital requirements to build gas-fired power generation facilities to serve our Colorado Electric, Black Hills Power and Cheyenne Light customers, and because of our upcoming holding company debt maturities, which are $225 million and $250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at their fair value prior to their mandatory early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair values on the termination dates.

In addition, we have $150 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of 5.25 years. These swaps have been designated as cash flow hedges, and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the accompanying Condensed Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $27.8 million at September 30, 2011.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2010 Annual Report on Form 10-K filed with the SEC.

Energy Marketing Commodities

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

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

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

Credit Ratings

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing, and vendor payment terms, including collateral requirements. As of September 30, 2011, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

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

In addition, as of September 30, 2011, Black Hills Power's first mortgage bonds were rated as follows:

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

Capital Requirements

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

	Expenditures for the Nine Months Ended September 30, 2011	Total 2011 Planned Expenditures	Total 2012 Planned Expenditures	Total 2013 Planned Expenditures
Utilities:				
Electric Utilities [(1) (2) (3)]	$131,824	$185,200	$231,500	$309,800
Gas Utilities	29,525	48,200	46,000	54,700
Non-regulated Energy:				
Oil and Gas [(4)]	59,294	79,100	97,200	123,500
Power Generation [(5)]	87,760	95,700	2,900	4,900
Coal Mining	7,856	12,800	18,800	7,200
Energy Marketing	2,075	4,200	5,400	5,700
Corporate	10,849	16,000	25,800	18,700
	$329,183	$441,200	$427,600	$524,500

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(1) The 2011 total planned expenditures include capital requirements associated with the on-going construction of the 180 MW gas-fired power generation facility to serve our Colorado Electric customers. We spent $57.6 million during the first nine months of 2011. The total construction cost of the facility is expected to be approximately $227 million, excluding transmission, and construction is expected to be completed by the end of 2011.

(2) Planned 2011 expenditures include expected spending of $9.6 million for a planned wind project for Colorado Electric.

(3) Planned generation expenditures for 2012 and 2013 include (a) $34.7 million for 2012 and $149.4 million for 2013 for 132 MW of new generation and related electric and gas transmission at Cheyenne Light and Black Hills Power for which the CPCN was filed on on November 1, 2011 subject to acceptance of the CPCN and receipt of air permits, (b) approximately $16.9 million for 2012 for our 50% share of the Colorado Electric wind project, subject to CPUC approval, (c) $43.5 million and $7.8 million, respectively, for 2012 and 2013 for the 88 MW of which 42 MW will be utility owned gas-fired generation at Colorado Electric, also subject to CPUC approval, and (d) $14.6 million for the Southern Connector Transmission Project at Colorado Electric in 2012.

(4) Our Oil and Gas segment planned expenditures in 2011 have increased $30.2 million from our planned expenditures disclosed in our 2010 Annual Report on Form 10-K, primarily due to development in the Bakken formation and our Mancos test program.

(5)

Our Power Generation segment was awarded the bid to provide 200 MW of generation capacity for a 20-year period to Colorado Electric. We spent $87.1 million during the first nine months of 2011. The total construction cost of the new facility is expected to be approximately $260 million, and construction is expected to be completed by the end of 2011.

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

Contractual Obligations

Unconditional purchase obligations for firm transportation and storage fees for our Energy Marketing segment decreased $13.3 million from $83.5 million at December 31, 2010 to $70.2 million at September 30, 2011. Approximately $36.9 million of the firm transportation and storage fee obligations relate to the 2011-2013 period with the remainder occurring thereafter.

Construction of a 180 MW power generation facility by our Colorado Electric utility and 200 MW power generation facility by our Power Generation segment is progressing. Cost of construction is expected to be approximately $227 million for Colorado Electric and $260 million for the Power Generation segment. Construction is expected to be completed at both facilities by December 31, 2011. As of September 30, 2011, we have committed contracts of 100% for the construction and construction was 99% complete for the Colorado Electric utility, and we have committed contracts of 100% and construction was 97% complete, for the Power Generation segment.

Colorado Electric filed a proposal with the CPUC to rate base 50% ownership in a 29 MW wind turbine project. As part of this project, on July 15, 2011, Colorado Electric signed a wind turbine supply agreement with Vestas-American Wind Technologies, Inc. for $33.3 million.

Guarantees

Except as noted below, there have been no changes to guarantees provided from those previously disclosed in Note 20 of our Notes to the Consolidated Financial Statements in our 2010 Annual Report on Form 10-K.

The guarantee for up to $7.0 million of the obligations of Enserco under an agency agreement expired in the first quarter of 2011.

The construction of the office building in Papillion, Nebraska was completed and the guarantee for $6.0 million was terminated upon purchase of the building in April 2011.

In June 2011, a guarantee to Colorado Interstate Gas was amended from $9.3 million to $10.0 million and the expiration date was extended to July 31, 2012. All other terms remained the same.

In June 2011, we issued a guarantee to Cross Timbers Energy Services for the performance and payment obligations of BHUH for natural gas supply purchases up to $7.5 million. The guarantee expires on June 30, 2012 or upon 30 days written notice to the counterparty.

In July 2011, we issued a guarantee to Vestas-American Wind Technology, Inc. for the performance and payment obligations of Colorado Electric for $33.3 million relating to the purchase of wind turbines for a Colorado Electric wind power generation project. This guarantee will remain in effect until satisfaction of Colorado Electric's contractual obligation. We expect the guarantee to expire on or about January 15, 2013.

New Accounting Pronouncements

Other than the pronouncements reported in our 2010 Annual Report on Form 10-K filed with the SEC and those discussed in Note 2 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial statements.

FORWARD-LOOKING INFORMATION

This report contains forward-looking information. All statements, other than statements of historical fact, included in this report that address activities, events, or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. Forward-looking information involves risks and uncertainties, and certain important factors can cause actual results to differ materially from those anticipated. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. The factors which may cause our results to vary significantly from our forward-looking statements include the risk factors described in Item 1A of our 2010 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q, and other reports that we file with the SEC from time to time, and the following:

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

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

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

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

- We expect to make approximately $441.2 million, $427.6 million and $525 million of capital expenditures in 2011, 2012 and 2013, respectively. Some important factors that could cause actual expenditures to differ materially from those anticipated include:

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

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

- Our ability to complete our planned capital expenditures associated with our Oil and Gas segment may be impacted by proposed government regulations and regulatory requirements, including those related to hydraulic fracturing services, availability of drilling rigs and other support services, and weather conditions.

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

- We expect contributions to our defined benefit pension plans to be approximately $0.0 million and $7.9 million for the remainder of 2011 and for 2012, respectively. Some important factors that could cause actual contributions to differ materially from anticipated amounts include:

- The actual value of the plans' invested assets.

- The discount rate used in determining the funding requirement.

- The outcome of pending labor negotiations relating to benefit participation of our collective bargaining agreements.

- We expect the goodwill related to our utility assets to fairly reflect the long-term value of stable, long-lived utility assets. Some important factors that could cause us to revisit the fair value of this goodwill include:

- A significant and sustained deterioration of the market value of our common stock.

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

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

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

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

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

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

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

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

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

The fair value of our Utilities Groups derivative contracts is summarized below (in thousands):

	September 30, 2011	December 31, 2010	September 30, 2010
Net derivative (liabilities) assets	$(10,064)	$(7,188)	$(16,078)
Cash collateral	12,058	10,355	20,519
	$1,994	$3,167	$4,441

Non-Regulated Trading Activities

The following table provides a reconciliation of Energy Marketing segment activity in our marketing portfolio that has been recorded at fair value including market value adjustments on inventory positions that have been designated as part of a fair value hedge during the nine months ended September 30, 2011 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2010	$23,418	(a)
Net cash settled during the period on positions that existed at December 31, 2010	4,674	
Unrealized gain (loss) on new positions entered during the period and still existing at September 30, 2011	10,876	
Realized (gain) loss on positions that existed at December 31, 2010 and were settled during the period	(18,121)	
Change in cash collateral	5,067	
Unrealized gain (loss) on positions that existed at December 31, 2010 and still exist at September 30, 2011	(9,059)	
Total fair value of marketing positions at September 30, 2011	$16,855	(a)

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

	September 30, 2011	June 30, 2011	March 31, 2011	December 31, 2010	September 30, 2010
Net derivative assets	$9,515	$27,415	$11,518	$28,524	$51,734
Cash collateral	9,026	1,250	2,984	3,958	(7,365)
Market adjustment recorded in material, supplies and fuel	(1,686)	(585)	316	(9,064)	(18,716)
Total fair value of energy marketing positions marked-to-market	$16,855	$28,080	$14,818	$23,418	$25,653

To value the assets and liabilities for our outstanding derivative contracts, we use the fair value methodology outlined in accounting standards for fair value measurements and disclosures. See Note 3 of the Notes to Consolidated Financial Statements in our 2010 Annual Report on Form 10-K and Note 12 and Note 13 of the accompanying Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

Source of Fair Value of Energy Marketing Positions	Maturities Less than 1 year	1 - 2 years	Total Fair Value
Cash collateral	$8,704	$322	$9,026
Level 1	—	—	—
Level 2	191	4,749	4,940
Level 3	(440)	5,015	4,575
Market value adjustment for inventory (see footnote (a) above)	(1,686)	—	(1,686)
Total fair value of our energy marketing positions	$6,769	$10,086	$16,855

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

The following table presents a reconciliation of our September 30, 2011 marketing positions recorded at fair value under GAAP to a non-GAAP measure of the fair value of our energy marketing forward book wherein all forward trading positions are marked-to-market (in thousands):

Fair value of our marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$16,855
Market value adjustments for inventory, storage and transportation positions that are part of our forward trading book, but that are not marked-to-market under GAAP	(6,722)
Fair value of all forward positions (non-GAAP)	10,133
Cash collateral included in GAAP marked-to-market fair value	(9,026)
Fair value of all forward positions excluding cash collateral (non-GAAP) *	$1,107

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

Except as discussed above, there have been no material changes in market risk from those reported in our 2010 Annual Report on Form 10-K filed with the SEC. For more information on market risk, see Part II, Items 7 and 7A. in our 2010 Annual Report on Form 10-K, and Note 12 of the Notes to our Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Activities Other Than Trading

We have entered into agreements to hedge a portion of our estimated 2011, 2012 and 2013 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at September 30, 2011 were as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)	Price
San Juan El Paso	10/23/2009	Swap	10/11 - 12/11	2,500	$6.23
NWR	10/23/2009	Swap	10/11 - 12/11	1,500	$6.12
AECO	12/11/2009	Swap	10/11 - 12/11	500	$6.27
CIG	12/11/2009	Swap	10/11 - 12/11	1,500	$6.03
San Juan El Paso	12/11/2009	Swap	10/11 - 12/11	5,000	$6.15
San Juan El Paso	1/8/2010	Swap	01/12 - 03/12	2,500	$6.38
NWR	1/8/2010	Swap	01/12 - 03/12	1,500	$6.47
AECO	1/8/2010	Swap	01/12 - 03/12	500	$6.32
CIG	1/8/2010	Swap	01/12 - 03/12	1,500	$6.43
San Juan El Paso	1/25/2010	Swap	01/12 - 03/12	5,000	$6.44
San Juan El Paso	3/19/2010	Swap	04/12 - 06/12	7,000	$5.27
CIG	3/19/2010	Swap	04/12 - 06/12	1,500	$5.17
NWR	3/19/2010	Swap	04/12 - 06/12	1,500	$5.20
AECO	3/19/2010	Swap	04/12 - 06/12	250	$5.15
San Juan El Paso	6/28/2010	Swap	07/12 - 09/12	3,500	$5.19
NWR	6/28/2010	Swap	07/12 - 09/12	1,500	$5.01
CIG	6/28/2010	Swap	07/12 - 09/12	1,500	$4.98
CIG	2/18/2011	Swap	10/12 - 12/12	500	$4.42
San Juan El Paso	2/18/2011	Swap	10/12 - 12/12	2,500	$4.46
NWR	2/18/2011	Swap	10/12 - 12/12	1,000	$4.44
San Juan El Paso	4/19/2011	Swap	07/12 - 09/12	2,000	$4.45
San Juan El Paso	4/19/2011	Swap	10/12 - 12/12	2,000	$4.62
San Juan El Paso	4/19/2011	Swap	01/13 - 03/13	2,500	$5.03
San Juan El Paso	4/19/2011	Swap	04/13 - 06/13	2,500	$4.64
San Juan El Paso	6/6/2011	Swap	01/13 - 03/13	2,500	$5.18

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	10/9/2009	Swap	10/11 - 12/11	5,000	$79.35
NYMEX	10/23/2009	Put	10/11 - 12/11	5,000	$75.00
NYMEX	11/19/2009	Swap	10/11 - 12/11	5,000	$87.50
NYMEX	1/8/2010	Put	10/11 - 12/11	6,000	$75.00
NYMEX	1/8/2010	Put	01/12 - 03/12	5,000	$75.00
NYMEX	1/25/2010	Swap	01/12 - 03/12	5,000	$83.30
NYMEX	2/26/2010	Swap	01/12 - 03/12	5,000	$83.80
NYMEX	3/19/2010	Swap	01/12 - 03/12	5,000	$83.80
NYMEX	3/19/2010	Swap	04/12 - 06/12	5,000	$84.00
NYMEX	3/31/2010	Put	04/12 - 06/12	5,000	$75.00
NYMEX	5/13/2010	Swap	04/12 - 06/12	5,000	$87.85
NYMEX	6/28/2010	Swap	07/12 - 09/12	5,000	$83.80
NYMEX	8/17/2010	Swap	04/12 - 06/12	3,000	$82.60
NYMEX	8/17/2010	Swap	07/12 - 09/12	5,000	$82.85
NYMEX	9/16/2010	Swap	07/12 - 09/12	5,000	$84.60
NYMEX	11/9/2010	Swap	10/12 - 12/12	5,000	$91.10
NYMEX	1/6/2011	Swap	10/12 - 12/12	5,000	$93.40
NYMEX	1/20/2011	Swap	01/13 - 03/13	5,000	$94.20
NYMEX	2/17/2011	Swap	10/12 - 03/13	5,000	$97.85
NYMEX	3/4/2011	Swap	07/11 - 12/11	5,000	$106.10
NYMEX	3/4/2011	Swap	01/12 - 12/12	2,000	$104.60
NYMEX	3/4/2011	Swap	01/13 - 03/13	3,000	$103.35
NYMEX	4/20/2011	Swap	07/12 - 06/13	2,000	$106.80
NYMEX	6/3/2011	Swap	04/13 - 06/13	5,000	$100.90
NYMEX	7/27/2011	Swap	04/13 - 06/13	5,000	$102.72
NYMEX	7/27/2011	Swap	07/13 - 12/13	5,000	$102.75

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. As of September 30, 2011, we had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 5.25 years. These swaps have been designated as hedges in accordance with accounting standards for derivatives and hedges and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the Condensed Consolidated Balance Sheets.

We also have interest rate swaps with a notional amount of $250.0 million which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were originally designated as cash flow hedges and the mark-to-market value was recorded in Accumulated other comprehensive loss on the Condensed Consolidated Balance Sheets. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the Condensed Consolidated Statement of Income. For the three months and nine months ended

September 30, 2011, we recorded pre-tax unrealized mark-to-market losses of $38.2 million and $40.6 million, respectively. For the three months and nine months ended September 30, 2010, we recorded pre-tax unrealized mark-to-market losses of $13.7 million and $41.7 million, respectively. These swaps are 7.25 and 17.25 year swaps which have amended mandatory early termination dates ranging from December 15, 2011 to December 29, 2011.

We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly our upcoming holding company debt maturities, which are $225 million and $250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at their fair value prior to their mandatory early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair values on the stated termination dates.

Further details of the swap agreements are set forth in Note 12 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

As of September 30, 2011, December 31, 2010 and September 30, 2010, our interest rate swaps and related balances were as follows (dollars in thousands):

	September 30, 2011		December 31, 2010		September 30, 2010	
	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	5.25	0.25	6.00	1.00	6.25	0.25
Derivative liabilities, current	$6,724	$94,588	$6,823	$53,980	$6,901	$80,450
Derivative liabilities, non-current	$21,108	$—	$14,976	$—	$21,518	$—
Pre-tax accumulated other comprehensive loss included in Condensed Consolidated Balance Sheets	$(27,832)	$—	$(21,799)	$—	$(28,419)	$—
Pre-tax (loss) gain included in Condensed Consolidated Statements of Income	$—	$(40,608)	$—	$(15,193)	$—	$(41,663)
Cash collateral receivable (payable) included in accounts receivable	$—	$—	$—	$—	$—	$25,000

* Maximum terms in years for our de-designed interest rate swaps reflect the amended mandatory early termination dates. If the mandatory early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date. When extended annually, de-designated swaps totaling $100 million terminate in 7.25 years and de-designated swaps totaling $150 million terminate in 17.25 years.

Based on September 30, 2011 market interest rates and balances for our $150 million notional interest rate swaps, a loss of approximately $6.7 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will likely change during the next 12 months as market interest rates change.

ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) as of September 30, 2011. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

There have been no changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2011 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 2010 Annual Report on Form 10-K and Note 15 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 15 is incorporated by reference into this item.

ITEM 1A. Risk Factors

Except as described below, there are no material changes to the Risk Factors previously disclosed in Item 1A of Part I in our Annual Report on Form 10-K for the year ended December 31, 2010.

The potential adoption of federal and state legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on our oil and natural gas properties. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the well-bore. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide the federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process.

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

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

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans for Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2011 - July 31, 2011	—	$—	—	—
August 1, 2011 - August 31, 2011	3,850	$28.91	—	—
September 1, 2011 - September 30, 2011	—	$—	—	—
Total	3,850	$28.91	—	—

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

ITEM 5. Other Information

Mine Safety and Health Administration Safety Data

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

Under the recently enacted Dodd-Frank Act, each operator of a coal or other mine is required to include certain mine safety results in its periodic reports filed with the SEC. Our mining operations, consisting of WRDC, are subject to regulation by the federal Mine Safety and Health Administration (“MSHA”) under the Federal Mine Safety and Health Act of 1977 (the “Mine Act”). Below we present the following information regarding certain mining safety and health matters for the three month period ended September 30, 2011. In evaluating this information, consideration should be given to factors such as: (i) the number of citations and orders will vary depending on the size of the coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process, are often reduced in severity and amount, and are sometimes dismissed. The information presented includes:

- Total number of violations of mandatory health and safety standards that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard under section 104 of the Mine Act for which we have received a citation from MSHA;

- Total number of orders issued under section 104(b) of the Mine Act;

- Total number of citations and orders for unwarrantable failure of the mine operator to comply with mandatory health and safety standards under section 104(d) of the Mine Act;

- Total number of imminent danger orders issued under section 107(a) of the Mine Act; and

- Total dollar value of proposed assessments from MSHA under the Mine Act.

During the three months ended September 30, 2011, WRDC (i) was not assessed any Mine Act section 110(b)(2) penalties for failure to correct the subject matter of a Mine Act section 104(a) citation within the specified time period, which failure was deemed flagrant (i.e., a reckless or repeated failure to make reasonable efforts to eliminate a known violation that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury); (ii) did not receive any Mine Act section 107(a) imminent danger orders to immediately remove miners; or (iii) did not receive any MSHA written notices under Mine Act section 104(e) of a pattern of violation of mandatory health or safety standards or of the potential to have such a pattern. In addition, there were no fatalities at the mine during the three months ended September 30, 2011.

The table below sets forth the total number of section 104 citations and/or orders issued by MSHA to WRDC under the indicated provisions of the Mine Act, together with the total dollar value of proposed MSHA assessments, received during the three months ended September 30, 2011 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for WRDC, our only mining complex. All citations were abated within 24 hours of issue.

Mine Act Section 104 Significant and Substantial Citations	Mine Act Section 104(b) Orders	Mine Act Section 104(d) Citations and Orders	Mine Act Section 107(a) Imminent Danger Orders	Total Dollar Value of Proposed MSHA Assessments	Number of Legal Actions Pending Before the Federal Mining Safety and Health Review Commission
—	—	—	—	$32,096	1

ITEM 6. Exhibits

Exhibit 10	First Amendment to the Credit Agreement dated December 15, 2010 among Black Hills Corporation, as Borrower, JPMorgan Chase Bank, N.A., in its capacity as agent for the Banks and as a Bank, and each of the other Banks (filed as Exhibit 10 to the Company's Form 8-K filed on October 3, 2011 and incorporated by reference herein).
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 101	Financials for XBRL Format

BLACK HILLS CORPORATION

Signatures

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

BLACK HILLS CORPORATION

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

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

Dated: November 4, 2011

EXHIBIT INDEX

Exhibit Number	Description
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