BLACK HILLS CORP /SD/
Form 10-Q
August 05, 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 June 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 July 29, 2011
Common stock, $1.00 par value	39,441,037 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 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

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
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
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
GAAP	Generally Accepted Accounting Principles
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
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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands, except per share amounts)			
Operating revenue:				
Utilities	$236,053	$220,168	$610,749	$608,834
Non-regulated energy	37,072	36,170	65,676	74,004
Total operating revenue	273,125	256,338	676,425	682,838
Operating expenses:				
Utilities -				
Fuel, purchased power and cost of gas sold	103,827	97,500	314,338	333,814
Operations and maintenance	58,689	66,029	126,098	131,063
Gain on sale of operating assets	—	—	—	(2,683)
Non-regulated energy operations and maintenance	28,359	25,106	57,570	48,066
Depreciation, depletion and amortization	32,334	30,260	64,321	58,655
Taxes - property, production and severance	7,242	6,239	15,460	12,716
Other operating expenses	52	369	303	670
Total operating expenses	230,503	225,503	578,090	582,301
Operating income	42,622	30,835	98,335	100,537
Other income (expense):				
Interest charges -				
Interest expense (including amortization of debt issuance costs, premium and discount, realized settlements on interest rate swaps)	(28,986)	(25,994)	(58,721)	(51,114)
Allowance for funds used during construction - borrowed	2,991	2,722	6,354	5,870
Capitalized interest	2,783	650	5,217	856
Interest rate swaps - unrealized (loss) gain	(7,827)	(24,918)	(2,362)	(27,953)
Interest income	475	84	1,035	330
Allowance for funds used during construction - equity	192	260	487	2,288
Other income, net	506	1,268	1,237	1,686
Total other income (expense)	(29,866)	(45,928)	(46,753)	(68,037)
Income (loss) before equity in earnings (loss) of unconsolidated subsidiaries and income taxes	12,756	(15,093)	51,582	32,500
Equity in earnings (loss) of unconsolidated subsidiaries	40	1,291	1,033	1,608
Income tax benefit (expense)	(5,044)	5,143	(17,953)	(11,333)
Net income (loss)	$7,752	$(8,659)	$34,662	$22,775
Weighted average common shares outstanding:				

Basic	39,109	38,902	39,084	38,875
Diluted	39,823	38,902	39,793	39,042
Earnings (loss) per share - basic	$0.20	$(0.22)	$0.89	$0.59
Earnings (loss) per share - diluted	$0.19	$(0.22)	$0.87	$0.58
Dividends paid per share of common stock	$0.365	$0.360	$0.730	$0.720

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)

	June 30, 2011	December 31, 2010	June 30, 2010
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$88,073	$32,438	$64,033
Restricted cash	3,710	4,260	16,169
Accounts receivable, net	244,829	328,811	208,185
Materials, supplies and fuel	105,608	139,677	135,049
Derivative assets, current	53,201	56,572	54,589
Income tax receivable, net	10,170	—	—
Deferred income tax assets, current	16,894	17,113	19,956
Regulatory assets, current	37,584	66,429	41,852
Other current assets	56,819	25,571	13,339
Total current assets	616,888	670,871	553,172
Investments	17,302	17,780	18,261
Property, plant and equipment	3,559,627	3,359,762	3,141,029
Less accumulated depreciation and depletion	(916,220)	(864,329)	(852,414)
Total property, plant and equipment, net	2,643,407	2,495,433	2,288,615
Other assets:			
Goodwill	354,831	354,831	353,734
Intangible assets, net	3,955	4,069	4,189
Derivative assets, non-current	14,630	9,260	9,726
Regulatory assets, non-current	139,309	138,405	121,026
Other assets, non-current	20,442	20,860	21,559
Total other assets	533,167	527,425	510,234
TOTAL ASSETS	$3,810,764	$3,711,509	$3,370,282

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)

	June 30, 2011	December 31, 2010	June 30, 2010
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$218,356	$279,069	$206,422
Accrued liabilities	140,814	170,301	130,194
Derivative liabilities, current	92,549	79,167	91,259
Accrued income taxes, net	—	779	13,974
Regulatory liabilities, current	17,220	3,943	22,447
Notes payable	380,000	249,000	225,000
Current maturities of long-term debt	3,613	5,181	4,539
Total current liabilities	852,552	787,440	693,835
Long-term debt, net of current maturities	1,183,583	1,186,050	990,130
Deferred credits and other liabilities:			
Deferred income tax liabilities, non-current	307,549	277,136	271,684
Derivative liabilities, non-current	19,258	21,361	18,177
Regulatory liabilities, non-current	83,643	84,611	50,227
Benefit plan liabilities	131,169	124,709	148,190
Other deferred credits and other liabilities	124,941	129,932	115,656
Total deferred credits and other liabilities	666,560	637,749	603,934
Stockholders' equity:			
Common stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 39,462,001, 39,280,048 and 39,204,231 shares, respectively	39,462	39,280	39,204
Additional paid-in capital	602,961	598,805	595,219
Retained earnings	491,208	486,075	468,430
Treasury stock at cost – 23,637, 10,962 and 1,021 shares, respectively	(691)	(309)	(27)
Accumulated other comprehensive income (loss)	(24,871)	(23,581)	(20,443)
Total stockholders' equity	1,108,069	1,100,270	1,082,383
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,810,764	$3,711,509	$3,370,282

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)

	Six Months Ended June 30, 2011	2010
Operating activities:	(in thousands)	
Net income (loss)	$34,662	$22,775
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	64,321	58,655
Derivative fair value adjustments	(9,939)	(2,445)
Gain on sale of operating assets	—	(2,683)
Stock compensation	3,259	1,971
Unrealized mark-to-market loss (gain) on interest rate swaps	2,362	27,953
Deferred income taxes	31,709	(6,078)
Equity in (earnings) loss of unconsolidated subsidiaries	(1,033)	(1,608)
Allowance for funds used during construction - equity	(487)	(2,288)
Employee benefit plans	7,287	8,143
Other, net	3,704	3,380
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	42,547	(19,896)
Accounts receivable and other current assets	44,540	93,873
Accounts payable and other current liabilities	(77,826)	(50,011)
Regulatory assets	32,029	(2,806)
Regulatory liabilities	11,573	13,401
Contributions to defined pension plans	(550)	—
Other operating activities	(6,141)	1,654
Net cash provided by operating activities	182,017	143,990
Investing activities:		
Property, plant and equipment additions	(225,863)	(171,115)
Proceeds from sale of ownership interest in operating assets	—	6,105
Payment for acquisition of assets	—	(2,250)
Other investing activities	799	4,239
Net cash provided by (used in) investing activities	(225,064)	(163,021)
Financing activities:		
Dividends paid	(29,530)	(28,202)
Common stock issued	1,437	2,281
Short-term borrowings - issuances	564,000	268,500
Short-term borrowings - repayments	(433,000)	(208,000)
Long-term debt - repayments	(4,052)	(56,488)
Other financing activities	(173)	(7,928)
Net cash provided by (used in) financing activities	98,682	(29,837)

Net change in cash and cash equivalents	55,635	(48,868)
Cash and cash equivalents, beginning of period	32,438	112,901
Cash and cash equivalents, end of period	$88,073	$64,033

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 (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 June 30, 2011, December 31, 2010 and June 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 six months ended June 30, 2011 and June 30, 2010, and our financial condition as of June 30, 2011, December 31, 2010, and June 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 have 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 $15.0 million and $30.8 million, in aggregate for the three and six months ended June 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.

(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

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. We believe 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 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 U.S. 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

	Six Months Ended June 30, 2011	June 30, 2010
	(in thousands)	
Non-cash investing activities—		
Property, plant and equipment acquired with accrued liabilities	$34,356	$32,207
Cash (paid) refunded during the period for—		
Interest (net of amounts capitalized)	$(49,909)	$(26,881)
Income taxes, net	$10,638	$(399)

(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):

	June 30, 2011	December 31, 2010	June 30, 2010
Materials and supplies	$36,685	$31,749	$32,361
Fuel - Electric Utilities	8,808	9,687	8,913
Natural gas in storage — Gas Utilities	15,914	21,691	15,513
Commodities held by Energy Marketing*	44,201	76,550	78,262
Total materials, supplies and fuel	$105,608	$139,677	$135,049

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* As of June 30, 2011, December 31, 2010 and June 30, 2010, market adjustments related to natural gas held by Energy Marketing and recorded in inventory as part of fair value hedge transactions were $(0.6) million, $(9.1) million and $(8.5) 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 June 30, 2011	Accounts Receivable, Trade	Unbilled Revenue	Total Accounts Receivable	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$38,067	$16,535	$54,602	$(685)	$53,917
Gas	33,572	11,891	45,463	(1,420)	44,043
Oil and Gas	7,803	—	7,803	(161)	7,642
Coal Mining	1,652	—	1,652	—	1,652
Energy Marketing	136,799	—	136,799	(173)	136,626
Power Generation	106	—	106	—	106
Corporate	843	—	843	—	843
Total	$218,842	$28,426	$247,268	$(2,439)	$244,829

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	12,247	—	12,247	—	12,247
Total	$271,226	$59,948	$331,174	$(2,363)	$328,811

As of June 30, 2010	Accounts Receivable, Trade	Unbilled Revenue	Total Accounts Receivable	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$38,511	$16,060	$54,571	$(1,051)	$53,520
Gas	29,291	10,676	39,967	(2,324)	37,643
Oil and Gas	4,678	—	4,678	(176)	4,502
Coal Mining	2,965	—	2,965	—	2,965
Energy Marketing	109,755	—	109,755	(746)	109,009
Power Generation	346	—	346	—	346
Corporate	200	—	200	—	200
Total	$185,746	$26,736	$212,482	$(4,297)	$208,185

Income Tax Receivable

Income tax receivable is primarily comprised of estimated payments made at the federal, state and foreign levels. The estimated payments relate to multiple prior tax years and were included in taxes payable at both December 31, 2010 and June 30, 2010. During second quarter of 2011, a refund (including an estimate of after-tax interest income) was received as a result of a settlement reached with the IRS in mid-2010 and finalized in early 2011.

(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 June 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 outstanding as of the Condensed Consolidated Balance Sheet dates (in thousands):

	As of June 30, 2011		As of December 31, 2010		As of June 30, 2010	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$130,000	$43,000	$149,000	$46,900	$225,000	$36,500
Enserco Credit Facility	—	118,700	—	166,900	—	141,400
Term Loan due 2011	100,000	—	100,000	—	—	—
Term Loan due 2012	150,000	—	—	—	—	—
Total	$380,000	$161,700	$249,000	$213,800	$225,000	$177,900

Revolving Credit Facility

Our $500.0 million Revolving Credit Facility expiring April 14, 2013 contains an accordion feature which allows us 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 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 June 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 June 30, 2011	Amortization Expense Three Months Ended June 30,		Six Months Ended June 30,	
		2011	2010	2011	2010
Deferred Financing Costs	$2,443	$473	$385	$946	$385

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 June 30, 2011.

	Actual	Covenant Requirement

Consolidated Net Worth	$1,108,069	$876,597
Recourse Leverage Ratio	59.3 %	65.0 %

Enserco Credit Facility

Enserco's two-year $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 June 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):

		Amortization Expense			
	Deferred Financing Costs Remaining on Balance Sheet as of	Three Months Ended June 30,		Six Months Ended June 30,	
	June 30, 2011	2011	2010	2011	2010
Deferred Financing Costs	$1,117	$293	$449	$561	$982

Corporate Term Loan

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 (1.44% at June 30, 2011). The covenants are substantially the same as those included in the Revolving Credit Facility and we were in compliance with these covenants as of June 30, 2011.

(7) EARNINGS PER SHARE

Basic earnings (loss) per share are computed by dividing net income by the weighted-average number of common shares outstanding during the period. Diluted earnings (loss) per share are 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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Net income (loss)	$7,752	$(8,659)	$34,662	$22,775
Weighted average shares - basic	39,109	38,902	39,084	38,875
Dilutive effect of:				
Restricted stock	148	—	140	99
Stock options	20	—	20	5
Forward equity issuance	533	—	496	—
Other	13	—	53	63
Weighted average shares - diluted	39,823	38,902	39,793	39,042

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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Stock options	102	137	81	228
Restricted stock	24	108	16	—
Other stock	31	64	15	—
	157	309	112	228

(8) COMPREHENSIVE INCOME (LOSS)

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

	Three Months Ended June 30, 2011	
Net income (loss)		$7,752
Other comprehensive income (loss), net of tax:		
Minimum pension liability adjustments	$—	
Taxes	—	
Minimum pension liability adjustments, net of tax		—
Fair value adjustment on derivatives designated as cash flow hedges	$(996)	
Taxes	231	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		(765)
Reclassification adjustments on cash flow hedges settled and included in net income (loss)	$1,617	
Taxes	(564)	
Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax		1,053
Comprehensive income (loss)		$8,040

	Three Months Ended June 30, 2010	
Net income (loss)		$(8,659)
Other comprehensive income (loss), net of tax:		
Minimum pension liability adjustments	$(27)	
Taxes	—	
Minimum pension liability adjustments, net of tax		(27)
Fair value adjustment on derivatives designated as cash flow hedges	$(2,029)	
Taxes	746	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		(1,283)
Reclassification adjustments on cash flow hedges settled and included in net income (loss)	$(5,117)	
Taxes	1,843	
Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax		(3,274)
Comprehensive income (loss)		$(13,243)

	Six Months Ended June 30, 2011	
Net income (loss)		$34,662
Other comprehensive income (loss), net of tax:		
Minimum pension liability adjustments	$—	
Taxes	—	
Minimum pension liability adjustments, net of tax		—
Fair value adjustment on derivatives designated as cash flow hedges	$(4,781)	
Taxes	1,868	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		(2,913)
Reclassification adjustments on cash flow hedges settled and included in net income (loss)	$2,478	
Taxes	(855)	
Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax		1,623
Comprehensive income (loss)		$33,372

	Six Months Ended June 30, 2010	
Net income (loss)		$22,775
Other comprehensive income (loss), net of tax:		
Minimum pension liability adjustments	$(8)	
Taxes	(7)	
Minimum pension liability adjustments, net of tax		(15)
Fair value adjustment on derivatives designated as cash flow hedges	$(22)	
Taxes	155	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		133
Reclassification adjustments on cash flow hedges settled and included in net income (loss)	$(2,179)	
Taxes	782	
Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax		(1,397)
Comprehensive income (loss)		$21,496

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

	June 30, 2011	December 31, 2010	June 30, 2010
Derivatives designated as cash flow hedges	$(13,729)	$(12,437)	$(10,751)
Employee benefit plans	(11,142)	(11,142)	(9,651)
Amount from equity-method investees	—	(2)	(41)
Total	$(24,871)	$(23,581)	$(20,443)

(9) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock during the six months ended June 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 six months ended June 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.

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

- We granted 132,270 shares of restricted common stock and restricted stock units during the six months ended June 30, 2011. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $4.0 million will be recognized over the 3 year vesting period.
- We granted 99,000 stock options at a weighted-average exercise price of $32.04 during the six months ended June 30, 2011. The total fair value of approximately $0.6 million will be recognized over the 3 year vesting period.
- Stock options totaling 4,500 were exercised during the six months ended June 30, 2011 at a weighted-average exercise price of $31.01 per share provided $0.1 million of proceeds.

Total compensation expense recognized for all equity compensation plans for the three months ended June 30, 2011 and 2010 was $0.9 million and $1.1 million, respectively, and for the six months ended June 30, 2011 and 2010 was $3.3 million and $2.9 million, respectively.

As of June 30, 2011, total unrecognized compensation expense related to non-vested stock awards was $9.9 million and is expected to be recognized over a weighted-average period of 2.1 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 50,724 new shares at a weighted-average price of $30.98 during the six months ended June 30, 2011. At June 30, 2011, 138,969 shares of unissued common stock were available for future offering under the DRIP Plan.

Dividend Restrictions

Our Revolving Credit Facility contains restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenants include the following: a recourse leverage ratio not to exceed 0.65 to 1.00 and a minimum consolidated net worth of $625 million plus 50.0% of aggregate consolidated net income, if positive, since January 1, 2005. As of June 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 shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed as of June 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 June 30, 2011, the restricted net assets at our Utilities Group were approximately $207.3 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 June 30, 2011 were $153.1 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 may settle the equity forward instrument at any time up to the maturity date of November 10, 2011. We may also unilaterally elect to cash or net share settle on any date up to maturity, for all or a portion of the equity forward shares. It is our intent to settle the equity forward with the physical delivery of shares in the fourth quarter of 2011.

At June 30, 2011, the equity forward instrument could have been settled with physical delivery of 4,413,519 shares in exchange for $123.2 million. Assuming required notices were given and actions taken, the forward instruments could also have been net settled at June 30, 2011 with delivery of cash of approximately $9.6 million or approximately 331,000 shares of common stock.

Based on the closing Black Hills Corporation common stock price on June 30, 2011, and the forward price on that date of the initial equity forward of $27.92 and over-allotment shares of $27.92, the fair value net cash settlement of the 4,413,519 shares was approximately $9.6 million.

(10) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

We have 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 the remaining Pension Plan covers certain eligible employees of Black Hills Energy. The Pension Plan benefits are based on years of service and compensation levels.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Service cost	$1,356	$1,533	$2,711	$3,066
Interest cost	3,732	3,773	7,464	7,546
Expected return on plan assets	(4,239)	(3,623)	(8,478)	(7,246)
Prior service cost	25	305	50	610
Net loss	1,135	500	2,270	1,000
Curtailment expense	—	—	—	—
Net periodic benefit cost	$2,009	$2,488	$4,017	$4,976

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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Service cost	$375	$377	$750	$754
Interest cost	542	611	1,084	1,222
Expected return on plan assets	(41)	(52)	(82)	(104)
Prior service benefit	(120)	(77)	(240)	(154)
Net transition obligation	—	—	—	—
Net loss (gain)	169	159	338	318
Net periodic benefit cost	$925	$1,018	$1,850	$2,036

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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Service cost	$257	$171	$514	$342
Interest cost	325	321	649	642
Prior service cost	1	1	2	2
Net loss	128	71	255	142
Net periodic benefit cost	$711	$564	$1,420	$1,128

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 are expected to be made in the form of benefit payments. Contributions are as follows (in thousands):

	Contributions Made Three Months Ended June 30, 2011	Contributions Made Six Months Ended June 30, 2011	Contributions Remaining for 2011	Contributions Anticipated for 2012
Defined Benefit Pension Plans	$550	$550	$10,000	$13,431
Non-pension Defined Benefit Postretirement Healthcare Plans	$882	$1,764	$1,765	$3,765
Supplemental Non-qualified Defined Benefit Plans	$235	$470	$472	$896

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(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 June 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 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 Idaho facilities;

- 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 June 30, 2011	External Operating Revenue	Inter-segment Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$136,131	$3,410	$8,614
Gas	99,922	—	4,440
Non-regulated Energy:			
Oil and Gas	18,838	—	(79)
Power Generation	891	6,889	548
Coal Mining	6,266	9,274	(381)
Energy Marketing	11,077	1,399	3,695
Corporate (a)	—	—	(9,092)

Inter-segment eliminations	—	(20,972)	7
Total	$273,125	$—	$7,752

Three Months Ended June 30, 2010	External Operating Revenue	Inter-segment Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$131,944	$4,321	$7,196
Gas	87,115	—	(886)
Non-regulated Energy:			
Oil and Gas	18,658	—	221
Power Generation	808	5,871	(416)
Coal Mining	7,805	7,244	3,074
Energy Marketing	8,881	14	1,327
Corporate [a]	—	—	(19,161)
Inter-segment eliminations	—	(16,323)	(14)
Total	$255,211	$1,127	$(8,659)

Six Months Ended June 30, 2011	External Operating Revenue	Inter-segment Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$280,561	$7,249	$18,863
Gas	330,188	—	23,703
Non-regulated Energy:			
Oil and Gas	36,744	—	(794)
Power Generation	1,739	13,661	1,734
Coal Mining	13,880	17,155	(1,679)
Energy Marketing	13,313	1,628	1,054
Corporate [a]	—	—	(8,158)
Inter-segment eliminations	—	(39,693)	(61)
Total	$676,425	$—	$34,662

Six Months Ended June 30, 2010	External Operating Revenue	Inter-segment Operating Revenue [c]	Net Income (Loss)
Utilities:			
Electric	$276,331	$8,743	$17,048
Gas [b]	330,285	—	18,612
Non-regulated Energy:			
Oil and Gas	38,401	—	2,569
Power Generation	2,142	12,605	664
Coal Mining	14,687	14,342	4,420
Energy Marketing	18,737	(70)	3,520
Corporate [a]	—	—	(24,128)
Inter-segment eliminations	—	(33,365)	70
Total	$680,583	$2,255	$22,775

(a) Net income (loss) includes a $5.1 million and a $1.5 million net after-tax mark-to-market loss on interest rate swaps for the three and six months ended June 30, 2011 and a $16.2 million and $18.2 million net after-tax loss on interest rate swaps for the three and six months ended June 30, 2010, respectively.

(b) 2010 Net income (loss) includes a $1.7 million after-tax gain on sale of operating assets in the Gas Utilities at Nebraska Gas.

(c) Total operating revenue has been restated to reflect elimination of intercompany activities previously not eliminated. See Note 1 for further discussion.

Total assets	June 30, 2011	December 31, 2010	June 30, 2010
Utilities:			
Electric [(a)]	$1,900,806	$1,834,019	$1,736,413
Gas	659,349	722,287	622,585
Non-regulated Energy:			
Oil and Gas	366,270	349,991	348,509
Power Generation [(a)]	353,794	293,334	197,545
Coal Mining	89,627	96,962	87,474
Energy Marketing	352,525	314,930	294,043
Corporate	88,393	99,986	83,713
Total	$3,810,764	$3,711,509	$3,370,282

(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 natural gas marketing transacted in Canadian dollars.

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

We actively manage our exposure to certain market risks as described in Note 3 of the Notes to our Consolidated Financial Statements in our 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 in Note 13.

Trading Activities

Our Energy Marketing segment is engaged in marketing of 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.

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. 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:

	Outstanding at June 30, 2011		Outstanding at December 31, 2010		Outstanding at June 30, 2010	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of MMBtus)						
Natural gas basis swaps purchased	607,228	45	399,128	22	238,853	21
Natural gas basis swaps sold	627,858	45	426,903	22	252,060	21
Natural gas fixed-for-float swaps purchased	216,067	27	135,005	33	67,103	39
Natural gas fixed-for-float swaps sold	213,106	30	150,803	22	86,200	19
Natural gas physical purchases	135,429	30	144,948	36	122,687	21
Natural gas physical sales	136,409	75	143,021	36	123,629	39
Natural gas futures purchased	18,270	10	—	—	—	—

Natural gas futures sold	31,630	10	—	—	—	—
Natural gas options purchased	—	—	—	—	—	—
Natural gas options sold	—	—	—	—	—	—

	Outstanding at June 30, 2011		Outstanding at December 31, 2010		Outstanding at June 30, 2010	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of Bbls)						
Crude oil physical purchases	5,765	10	5,628	16	4,673	6
Crude oil physical sales	5,680	10	6,921	16	4,754	6
Crude oil fixed-for-float swaps purchased	230	1	20	3	—	—
Crude oil fixed-for-float swaps sold	420	3	240	4	140	4

	Outstanding at June 30, 2011		Outstanding at December 31, 2010		Outstanding at June 30, 2010	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of tons)						
Coal fixed-for-float swaps purchased	6,040	30	4,060	36	6,910	29
Coal fixed-for-float swaps sold	7,025	30	3,720	36	4,985	30
Coal physical purchases	27,761	42	24,634	48	24,925	54
Coal physical sales	11,584	30	9,046	36	6,472	38
Coal options purchased	4,278	54	2,835	48	334	42
Coal options sold	602	6	270	12	1,804	30

	Outstanding at June 30, 2011		Outstanding at December 31, 2010		Outstanding at June 30, 2010	
(in thousands of MWh):	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
Power physical purchases	—	—	—	—	—	—
Power physical sales	157	57	—	—	—	—
Power fixed-for-float swaps purchased	6,568	30	—	—	—	—
Power fixed-for-float swaps sold	6,848	30	—	—	—	—

	Outstanding at June 30, 2011		Outstanding at December 31, 2010		Outstanding at June 30, 2010	
(in thousands of MWh):	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
Environmental products physical purchases	70	15	—	—	—	—
Environmental products physical sales	157	57	—	—	—	—

Derivatives and certain other marketing transactions were marked to fair value at June 30, 2011, December 31, 2010 and June 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):

	June 30, 2011	December 31, 2010	June 30, 2010
Current derivative assets	$43,657	$43,862	$41,576
Non-current derivative assets	$13,907	$6,635	$5,888
Current derivative liabilities	$26,922	$14,550	$15,912
Non-current derivative liabilities	$1,977	$3,464	$(168)
Cash collateral (receivable)/payable included in derivative assets/liabilities	$1,250	$3,958	$—
Unrealized gain	$27,415	$28,525	$31,720
Credit risk-related contingent features that require us to maintain a specific credit rating.	$—	$—	$—

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 June 30, 2011, December 31, 2010 and June 30, 2010, the market adjustments recorded in inventory were $(0.6) million, $(9.1) million and $(8.5) 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):

	June 30, 2011		December 31, 2010		June 30, 2010	
	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps
Notional*	463,500	5,969,250	424,500	6,821,800	520,500	9,397,800
Maximum terms in years **	1.00	0.25	0.25	0.25	0.25	0.50
Derivative assets, current	$449	$6,160	$248	$7,675	$2,040	$6,855
Derivative assets, non-current	$214	$456	$19	$2,606	$855	$2,983
Derivative liabilities, current	$2,385	$—	$3,814	$—	$2,170	$44
Derivative liabilities, non-current	$1,201	$117	$1,301	$—	$178	$4
Pre-tax accumulated other comprehensive income (loss) included in Condensed Consolidated Balance Sheets	$3,173	$6,499	$(5,313)	$10,281	$(161)	$9,790
Earnings	$250	$—	$465	$—	$708	$—

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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 June 30, 2011 market prices, a $3.9 million gain would be realized and reported in pre-tax earnings during the next 12 months related to hedges of production. Estimated and actual realized gains will likely change during the next 12 months as market prices change.

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 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 June 30, 2011		Outstanding at December 31, 2010		Outstanding at June 30, 2010	
	Notional Amounts (MMBtus)	Latest Expiration (months)	Notional Amounts (MMBtus)	Latest Expiration (months)	Notional Amounts (MMBtus)	Latest Expiration (months)
Natural gas futures purchased	7,820,000	21	6,670,000	15	8,230,000	21
Natural gas options purchased	1,560,000	9	1,730,000	3	1,520,000	9
Natural gas basis swaps purchased	—	—	—	—	—	—

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

	June 30, 2011	December 31, 2010	June 30, 2010
Current derivative assets	$2,935	$4,787	$3,806
Non-current derivative assets	$53	$—	$—
Non-current derivative liabilities	$175	$1,620	$612
Net unrealized gain (loss) included in regulatory assets or regulatory liabilities	$(4,229)	$8,030	$7,150
Cash collateral (receivable) payable included in derivative assets/liabilities	$(6,254)	$(10,355)	$(9,551)
Option premium included in Derivative assets, current	$760	$842	$792

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):

	June 30, 2011		December 31, 2010		June 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	5.50	0.50	6.00	1.00	6.50	0.50
Derivative liabilities, current	$6,900	$56,342	$6,823	$53,980	$6,393	$66,740
Derivative liabilities, non-current	$15,788	$—	$14,976	$—	$17,551	$—
Pre-tax accumulated other comprehensive loss included in Condensed Consolidated Balance Sheets	$(22,688)	$—	$(21,799)	$—	$(23,944)	$—
Pre-tax (loss) gain included in Condensed Consolidated Statements of Income	$—	$(2,362)	$—	$(15,193)	$—	$(27,953)
Cash collateral (receivable) payable included in accounts receivable	$—	$—	$—	$—	$—	$—

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* 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. When extended annually, de-designated swaps totaling $100 million terminate in 7.5 years and de-designated swaps totaling $150 million terminate in 17.5 years.

Based on June 30, 2011 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $6.9 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 Contracts

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

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

	As of June 30, 2011		As of December 31, 2010		As of June 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 June 30, 2011	As of December 31, 2010	As of June 30, 2010
Fair Value	$—	$(143)	$—

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Unrealized foreign exchange gain (loss)	$90	$(48)	$(162)	$84
Realized foreign exchange gain (loss)	$100	$(450)	$438	$(591)

(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 June 30, 2011					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Energy Marketing	$—	$200,447	$14,536	$(156,755)	$(664)	$57,564
Commodity derivatives — Oil and Gas	—	7,168	111	—	—	7,279
Commodity derivatives — Regulated Utilities Group	—	(3,266)	—	—	6,254	2,988
Money market funds	6,006	—	—	—	—	6,006
Total	$6,006	$204,349	$14,647	$(156,755)	$5,590	$73,837
Liabilities:						
Commodity derivatives — Energy Marketing	$—	$179,348	$8,220	$(156,755)	$(1,914)	$28,899
Commodity derivatives — Oil and Gas	—	3,703	—	—	—	3,703
Commodity derivatives — Regulated Utilities Group	—	175	—	—	—	175
Foreign currency derivatives	—	—	—	—	—	—
Interest rate swaps	—	79,030	—	—	—	79,030
Total	$—	$262,256	$8,220	$(156,755)	$(1,914)	$111,807

	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	$(124,049)	$—	$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	$(124,049)	$10,355	$73,882
Liabilities:						
Commodity derivatives — Energy Marketing	$—	$143,537	$2,463	$(131,965)	$3,958	$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	$(131,965)	$3,958	$100,528

	As of June 30, 2010					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Energy Marketing	$—	$173,008	$3,411	$(128,909)	$—	$47,510
Commodity derivatives — Oil and Gas	—	11,422	1,265	—	—	12,687
Commodity derivatives — Regulated Utilities Group	—	(5,433)	—	—	9,551	4,118
Money market funds	9,006	—	—	—	—	9,006
Foreign currency derivatives	—	—	—	—	—	—
	$9,006	$178,997	$4,676	$(128,909)	$9,551	$73,321
Liabilities:						
Commodity derivatives — Energy Marketing	$—	$142,184	$2,500	$(128,908)	$—	$15,776
Commodity derivatives — Oil and Gas	—	2,349	—	—	—	2,349
Commodity derivatives — Regulated Utilities Group	—	612	—	—	—	612
Foreign currency derivatives	—	15	—	—	—	15
Interest rate swaps	—	90,684	—	—	—	90,684
Total	$—	$235,844	$2,500	$(128,908)	$—	$109,436

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

	Three Months Ended June 30, 2011 Commodity Derivatives	Six Months Ended June 30, 2011 Commodity Derivatives
Balance as of beginning of period	$4,413	$5,779
Unrealized losses	3,577	(2,622)
Unrealized gains	(648)	5,553
Purchases	—	—
Issuances	—	—
Settlements	261	(1,958)
Transfers into level 3 [(a)]	(1,074)	(254)
Transfers out of level 3[(b)]	(102)	(71)
Balances at end of period	$6,427	$6,427
Changes in unrealized gains relating to instruments still held as of period-end	$1,267	$240

	Three Months Ended June 30, 2010 Commodity Derivatives	Six Months Ended June 30, 2010 Commodity Derivatives
Balance as of beginning of period	$1,295	$(556)
Unrealized losses	(952)	(2,167)
Unrealized gains	2,345	3,726
Settlements	(498)	(805)
Transfers into level 3 [(a)]	(16)	(16)
Transfers out of level 3[(b)]	2	1,994
Balances at end of period	$2,176	$2,176
Changes in unrealized losses relating to instruments still held as of period-end	$66	$1,811

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

(b) Transfers out of level 3 represent assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

Gains and losses (realized and unrealized) for level 3 commodity derivatives totaling $3.0 million and $3.0 million for the three and six months ended June 30, 2011, respectively, are included in Operating revenue on the accompanying Condensed Consolidated Statements of Income while $(0.1) million and $(0.1) million was recorded through Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets for the three and six months ended June 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 $7.5 million, $14.3 million and $9.6 million on deposit in margin accounts at June 30, 2011, December 31, 2010, and June 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 June 30, 2011

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$849	$74
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	79
Commodity derivatives	Derivative liabilities — non-current	—	—
Interest rate swaps	Derivative liabilities — current	—	6,900
Interest rate swaps	Derivative liabilities — non-current	—	15,788
Total derivatives designated as hedges		$849	$22,841
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$198,892	$152,056
Commodity derivatives	Derivative assets — non-current	40,249	25,619
Commodity derivatives	Derivative liabilities — current	27,819	59,070
Commodity derivatives	Derivative liabilities — non-current	686	4,047
Foreign currency derivatives	Derivative liabilities — current	—	—
Interest rate swaps	Derivative liabilities — current	—	56,342
Total derivatives not designated as hedges		$267,646	$297,134

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 June 30, 2010

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$9,790	$1,369
Commodity derivatives	Derivative assets — non-current	6	—
Commodity derivatives	Derivative liabilities — current	16	8
Commodity derivatives	Derivative liabilities — non-current	—	8
Interest rate swaps	Derivative liabilities — current	—	6,393
Interest rate swaps	Derivative liabilities — non-current	—	17,551
Total derivatives designated as hedges		$9,812	$25,329
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$151,994	$115,377
Commodity derivatives	Derivative assets — non-current	20,657	10,937
Commodity derivatives	Derivative liabilities — current	13,891	32,010
Commodity derivatives	Derivative liabilities — non-current	—	618
Interest rate swaps	Derivative liabilities — current	—	66,740
Interest rate swaps	Derivative liabilities — non-current	—	—
Foreign currency derivatives	Derivative asset — current	—	15
Foreign currency derivatives	Derivative liabilities — current	—	—
Total derivatives not designated as hedges		$186,542	$225,697

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 six months ended June 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 June 30, 2011	Six Months Ended June 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	$980	$(8,737)
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	(903)	8,479
		$77	$(258)

		Three Months Ended June 30, 2010	Six Months Ended June 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	$(3,199)	$8,009
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	2,569	(8,178)
		$(630)	$(169)

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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 June 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	$(4,768)	Interest expense	$(1,919)		$—
Commodity derivatives	3,772	Operating revenue	302	Operating revenue	—
Total	$(996)		$(1,617)		$—

Three Months Ended June 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	$(9,812)	Interest expense	$(3,519)		$—
Commodity derivatives	(491)	Operating revenue	(5,191)	Operating revenue	(154)
Total	$(10,303)		$(8,710)		$(154)

Six Months Ended June 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	$(4,470)	Interest expense	$(3,811)		$—
Commodity derivatives	(311)	Operating revenue	1,333	Operating revenue	—
Total	$(4,781)		$(2,478)		$—

Six Months Ended June 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	$(11,886)	Interest expense	$(3,824)		$—
Commodity derivatives	6,090	Operating revenue	(1,948)	Operating revenue	(317)
Total	$(5,796)		$(5,772)		$(317)

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 June 30, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income	Six Months Ended June 30, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$8,438	$4,208
Interest rate swaps - unrealized	Interest rate swaps — unrealized (loss) gain	(7,827)	(2,362)
Interest rate swaps - realized	Interest expense	(3,352)	(6,704)
Foreign currency contracts	Operating revenue	106	(143)
		$(2,635)	$(5,001)

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended June 30, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income	Six Months Ended June 30, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$6,868	$4,209
Interest rate swaps - unrealized	Interest rate swaps — unrealized (loss) gain	(24,918)	(27,953)
Interest rate swaps - realized	Interest expense	(2,863)	(6,180)
Foreign currency contracts	Operating revenue	(15)	(15)
		$(20,928)	$(29,939)

(14) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	June 30, 2011		December 31, 2010		June 30, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$88,073	$88,073	$32,438	$32,438	$64,033	$64,033
Restricted cash	$3,710	$3,710	$4,260	$4,260	$16,169	$16,169
Derivative financial instruments - assets	$67,831	$67,831	$65,832	$65,832	$64,315	$64,315
Derivative financial instruments - liabilities	$111,807	$111,807	$100,528	$100,528	$109,436	$109,436
Notes payable	$380,000	$380,000	$249,000	$249,000	$225,000	$225,000
Long-term debt, including current maturities	$1,187,196	$1,313,052	$1,191,231	$1,290,519	$994,669	$1,101,903

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

Cash, Cash Equivalents

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

Restricted Cash

Restricted cash is primarily related to cash held in escrow required by Black Hills Wyoming project financing agreements. Some of these funds are held in 30-day guaranteed investment certificates.

Derivative Financial Instruments

Derivative financial instruments are carried at fair value. Our fair value measurements are developed using a variety of inputs by our risk management group, which is independent of the trading function. These inputs include unadjusted quoted prices where available; prices published by various third-party providers; and, when necessary, internally developed adjustments. In many cases, the internally developed prices are corroborated with external sources. Some of our transactions take place in markets with limited liquidity and limited price visibility. Additionally, descriptions of the various instruments we use and the valuation method employed are included in Notes 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 six 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 June 30, 2011, cannot be reasonably determined and could have a material adverse effect on our results of operations or financial position.

Guarantees

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.

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.

In June 2011, a guarantee to Colorado Interstate Gas was amended. It was increased 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 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 counterpart.

Other Commitments

Construction of a 180 MW power generation facility by our Colorado Electric utility and a 200 MW power generation facility by our Power Generation segment is progressing. Cost of construction is expected to be approximately $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. As our plans progress, we are in the process of procuring or have procured contracts for the turbines, building construction and labor. As of June 30, 2011, committed contracts for equipment purchases and for construction were 100% and 95% complete, respectively, for the Colorado Electric utility and 100% and 94% complete, respectively, 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 40 MW of energy and capacity to Cheyenne Light from Black Hills Wyoming's Gillette CT.

(16) SUBSEQUENT EVENT

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 obligations. We expect the guarantee to expire on or about January 15, 2013.

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 six months ended June 30, 2011, and our financial condition as of June 30, 2011, December 31, 2010, and June 30, 2010 and 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 June 30, 2011 Compared to Three Months Ended June 30, 2010. Net income for the three months ended June 30, 2011 was $7.8 million, or $0.19 per share, compared to Net loss of $8.7 million, or $0.22 per share, reported for the same period in 2010. The 2011 Net income includes a $5.1 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps. The 2010 Net loss included a $16.2 million after-tax unrealized mark-to-market loss on these same interest rate swaps.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010. Net income for the six months ended June 30, 2011 was $34.7 million, or $0.87 per share, compared to $22.8 million, or $0.58 per share, reported for the same period in 2010. The 2011 Net income includes a $1.5 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps. The 2010 Net income included an $18.2 million after-tax mark-to-market loss on these same interest rate swaps and a $1.7 million after-tax gain on the sale of assets of Nebraska Gas.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
Operating Revenue *						
Utilities	$239,463	$223,380	$16,083	$617,998	$615,359	$2,639
Non-regulated Energy	54,634	49,281	5,353	98,120	100,844	(2,724)
Intercompany eliminations	(20,972)	(16,323)	(4,649)	(39,693)	(33,365)	(6,328)
	$273,125	$256,338	$16,787	$676,425	$682,838	$(6,413)
Net income (loss)						
Electric Utilities	$8,614	$7,196	1,418	$18,863	$17,048	$1,815
Gas Utilities	4,440	(886)	5,326	23,703	18,612	5,091
Utilities	13,054	6,310	6,744	42,566	35,660	6,906
Oil and Gas	(79)	221	(300)	(794)	2,569	(3,363)
Power Generation	548	(416)	964	1,734	664	1,070
Coal Mining	(381)	3,074	(3,455)	(1,679)	4,420	(6,099)
Energy Marketing	3,695	1,327	2,368	1,054	3,520	(2,466)
Non-regulated Energy	3,783	4,206	(423)	315	11,173	(10,858)
Corporate	(9,092)	(19,161)	10,069	(8,158)	(24,128)	15,970
Inter-company eliminations	7	(14)	21	(61)	70	(131)
	$7,752	$(8,659)	$16,411	$34,662	$22,775	$11,887

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* 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 are as follows:

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, 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

- 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 $204 million has been expended through June 30, 2011;

- On August 1, 2011, Cheyenne Light filed a CPCN with the WPSC requesting approval to construct and operate a new $158 million 120 MW electric generation facility. The new generation will include three simple-cycle, gas-fired combustion turbines each with a capacity of 40 MW. Pending WPSC approval, commercial operation would commence in 2014;

- 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. The dismissal resulted in a decision by Black Hills Power not to proceed with this project;

- 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 of $3.1 million;

- On April 28, 2011, Colorado Electric filed a request with the CPUC for a revenue increase of $40.2 million to recover costs and a return associated with the 180 MW generation project and other utility infrastructure assets and expenses, including PPA costs associated with the 200 MW Colorado IPP generation facility. The proposed rate increase would go into effect on January 1, 2012 to coincide with the expiration of the PPA with PSCo that is being replaced with the new 380 MW of gas-fired generation. A hearing on the rate case with the CPUC has been scheduled for late October 2011;

- On March 24, 2011, Colorado Electric filed a proposal with 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. Our 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. A settlement has been reached and a decision by the CPUC is pending; and

- On March 14, 2011, Colorado Electric filed a request for a CPCN to construct a third utility-owned 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 third turbine. The CPCN approval is pending.

Non-regulated Energy Group

- Construction of gas-fired generation at 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 $226 million has been expended through June 30, 2011; and

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

Corporate

- We recognized a non-cash unrealized mark-to-market loss related to certain interest rate swaps of $2.4 million for the six months ended June 30, 2011 compared to a $28.0 million unrealized mark-to-market loss on these swaps for the same period in 2010; and

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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.

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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Revenue — electric	$132,978	$128,408	$267,848	$261,176
Revenue — gas	6,563	7,857	19,962	23,898
Total revenue	139,541	136,265	287,810	285,074
Fuel and purchased power — electric	66,254	64,794	131,932	138,305
Purchased gas	3,484	4,581	11,880	15,772
Total fuel and purchased power	69,738	69,375	143,812	154,077
Gross margin — electric	66,724	63,614	135,916	122,871
Gross margin — gas	3,079	3,276	8,082	8,126
Total gross margin	69,803	66,890	143,998	130,997
Operations and maintenance	34,156	35,956	71,270	68,724
Gain on sale of operating assets	—	—	—	—
Depreciation and amortization	13,006	11,897	25,830	23,086
Total operating expenses	47,162	47,853	97,100	91,810
Operating income	22,641	19,037	46,898	39,187
Interest expense, net	(10,107)	(8,448)	(20,051)	(16,702)
Other income (expense)	(53)	315	356	2,440
Income tax expense	(3,867)	(3,708)	(8,340)	(7,877)
Net income	$8,614	$7,196	$18,863	$17,048

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Revenue - electric (in thousands)	2011	2010	2011	2010
Residential:				
Black Hills Power	$12,773	$11,546	$29,943	$26,025
Cheyenne Light	7,026	6,785	15,097	14,710
Colorado Electric	19,155	16,607	39,591	36,023
Total Residential	38,954	34,938	84,631	76,758
Commercial:				
Black Hills Power	17,759	16,104	35,073	30,643
Cheyenne Light	13,495	13,416	26,038	25,872
Colorado Electric	18,373	16,005	34,958	31,695
Total Commercial	49,627	45,525	96,069	88,210
Industrial:				
Black Hills Power	6,464	6,204	12,228	10,841
Cheyenne Light	2,944	2,882	5,556	5,412
Colorado Electric	8,567	6,841	16,434	13,785
Total Industrial	17,975	15,927	34,218	30,038
Municipal:				
Black Hills Power	783	748	1,517	1,401
Cheyenne Light	455	237	846	468
Colorado Electric	3,186	2,871	6,122	4,558
Total Municipal	4,424	3,856	8,485	6,427
Contract Wholesale:				
Black Hills Power	4,370	7,078	8,990	13,796
Off-system Wholesale:				
Black Hills Power	7,442	8,539	14,395	17,255
Cheyenne Light	2,580	2,119	5,467	4,710
Colorado Electric (a)	—	2,903	—	10,236
Total Off-system Wholesale	10,022	13,561	19,862	32,201
Other:				
Black Hills Power	6,507	6,219	13,146	10,966
Cheyenne Light	567	789	1,256	1,701
Colorado Electric	532	515	1,191	1,079
Total Other	7,606	7,523	15,593	13,746
Total Revenue - electric	$132,978	$128,408	$267,848	$261,176

(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 $3.5 million and $6.4 million in off-system revenue during the three and six months ended June 30, 2011, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
Quantities Generated and Purchased (in MWh)	2011	2010	2011	2010
Generated —				
Coal-fired:				
Black Hills Power	386,006	559,258	823,844	989,831
Cheyenne Light	169,195	181,475	340,566	357,899
Colorado Electric	71,236	55,993	127,911	126,244
Total Coal	626,437	796,726	1,292,321	1,473,974
Gas and Oil-fired:				
Black Hills Power	1,147	1,106	2,171	3,944
Cheyenne Light	—	—	—	—
Colorado Electric	30	93	30	93
Total Gas and Oil-fired	1,177	1,199	2,201	4,037
Total Generated:				
Black Hills Power	387,153	560,364	826,015	993,775
Cheyenne Light	169,195	181,475	340,566	357,899
Colorado Electric	71,266	56,086	127,941	126,337
Total Generated	627,614	797,925	1,294,522	1,478,011
Purchased —				
Black Hills Power	401,218	290,518	776,830	720,200
Cheyenne Light	179,079	151,570	376,248	344,427
Colorado Electric	486,052	487,956	968,837	1,029,158
Total Purchased	1,066,349	930,044	2,121,915	2,093,785
Total Generated and Purchased:				
Black Hills Power	788,371	850,882	1,602,845	1,713,975
Cheyenne Light	348,274	333,045	716,814	702,326
Colorado Electric	557,318	544,042	1,096,778	1,155,495
Total Generated and Purchased	1,693,963	1,727,969	3,416,437	3,571,796

	Three Months Ended June 30,		Six Months Ended June 30,	
Quantity Sold (in MWh)	2011	2010	2011	2010
Residential:				
Black Hills Power	107,683	113,903	282,083	288,438
Cheyenne Light	58,532	59,152	131,410	133,972
Colorado Electric	138,644	137,581	295,999	304,610
Total Residential	304,859	310,636	709,492	727,020
Commercial:				
Black Hills Power	167,649	164,863	345,886	349,301
Cheyenne Light	143,645	143,915	289,244	289,124
Colorado Electric	180,168	181,641	345,902	352,595
Total Commercial	491,462	490,419	981,032	991,020
Industrial:				
Black Hills Power	105,861	101,425	194,610	188,088
Cheyenne Light	42,642	43,671	83,470	84,430
Colorado Electric	91,188	85,484	175,097	169,994
Total Industrial	239,691	230,580	453,177	442,512
Municipal:				
Black Hills Power	7,739	7,577	16,041	15,803
Cheyenne Light	2,150	679	4,594	1,613
Colorado Electric	32,079	33,638	59,826	49,416
Total Municipal	41,968	41,894	80,461	66,832
Contract Wholesale:				
Black Hills Power (a)	82,253	120,258	172,212	288,723
Off-system Wholesale:				
Black Hills Power	278,086	299,064	520,242	530,111
Cheyenne Light	79,741	63,995	163,926	148,262
Colorado Electric (b)	94,945	73,513	173,448	233,288
Total Off-system Wholesale	452,772	436,572	857,616	911,661
Total Quantity Sold:				
Black Hills Power	749,271	807,090	1,531,074	1,660,464
Cheyenne Light	326,710	311,412	672,644	657,401
Colorado Electric	537,024	511,857	1,050,272	1,109,903
Total Quantity Sold	1,613,005	1,630,359	3,253,990	3,427,768
Losses and Company Use:				
Black Hills Power	39,100	43,792	71,771	53,511
Cheyenne Light	21,564	21,633	44,170	44,925
Colorado Electric	20,294	32,185	46,506	45,592
Total Losses and Company Use	80,958	97,610	162,447	144,028
Total Energy	1,693,963	1,727,969	3,416,437	3,571,796

(a) Decrease in 2011 MWh is due to the termination of a wholesale contract with a previous wholesale power customer who 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 determined. In accordance with this agreement, operating income for off-system MWh sold at Colorado Electric totaling $0.1 million and $0.2 million have been deferred in accordance with an agreement with the CPUC for the three and six months ended June 30, 2011. Operating income of $1.1 million has been deferred since the rate case was approved in August 2010.

	Three Months Ended June 30,			
Degree Days	2011		2010	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Actual —				
Black Hills Power	1,190	19 %	904	9 %
Cheyenne Light	1,354	10 %	1,308	6 %
Colorado Electric	638	(1)%	647	1 %
Cooling Degree Days:				
Actual —				
Black Hills Power	56	(45)%	65	(37)%
Cheyenne Light	30	(29)%	35	(17)%
Colorado Electric	294	36 %	280	30 %

	Six Months Ended June 30,			
Degree Days	2011		2010	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Actual —				
Black Hills Power	4,897	14 %	4,296	4 %
Cheyenne Light	4,477	2 %	4,418	1 %
Colorado Electric	3,419	4 %	3,424	4 %
Cooling Degree Days:				
Actual —				
Black Hills Power	56	(45)%	65	(37)%
Cheyenne Light	30	(29)%	35	(17)%
Colorado Electric	294	36 %	280	30 %

Electric Utilities Power Plant Availability	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Coal-fired plants	88.6 % (a)	90.0 % (b)	89.9 % (a)	91.3 % (b)
Other plants	89.9 % (c)	97.4 %	94.3 %	98.6 %
Total availability	89.0 %	92.6 %	91.5 %	93.9 %

(a) Reflects a planned major outage at the PacifiCorp-operated Wyodak plant.

(b) Reflects an unplanned outage at the PacifiCorp-operated Wyodak plant.

(c) Reflects a planned major overhaul at Neil Simpson CT.

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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Revenue (in thousands):				
Residential	$4,053	$4,770	$12,031	$14,283
Commercial	1,739	2,222	5,546	7,055
Industrial	580	663	1,856	2,121
Other	191	202	529	439
Total Revenue	$6,563	$7,857	$19,962	$23,898
Gross Margin (in thousands):				
Residential	$2,332	$2,298	$5,720	$5,550
Commercial	694	752	1,906	1,969
Industrial	98	60	275	227
Other	(45)	166	181	380
Total Gross Margin	$3,079	$3,276	$8,082	$8,126
Volumes Sold (Dth):				
Residential	497,250	555,636	1,565,711	1,695,179
Commercial	302,543	331,723	926,266	992,841
Industrial	140,135	135,370	396,656	377,545
Total Volumes Sold	939,928	1,022,729	2,888,633	3,065,565

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010. Net income for the Electric Utilities segment was $8.6 million for the three months ended June 30, 2011 compared to $7.2 million for the three months ended June 30, 2010 as a result of:

Gross margin increased $2.9 million primarily due to recently approved rate adjustments that include a return on significant capital investments, partially offset by lower margins resulting from the termination of power sales contracts upon a customer's purchase of an ownership interest in Wygen III in 2010.

Operations and maintenance decreased $1.8 million primarily due to unplanned maintenance expenditures at the PacifiCorp-operated Wyodak plant in 2010 partially offset by increased allocation of corporate costs.

Depreciation and amortization increased $1.1 million primarily due to higher asset base.

Interest expense, net increased $1.7 million due to higher debt balances associated with recent capital investments.

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

Income tax expense: The effective tax rate was comparable to the same period in the prior year.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010. Net income for the Electric Utilities segment was $18.9 million for the six months ended June 30, 2011 compared to $17.0 million for the six months ended June 30, 2010 as a result of:

Gross margin increased $13.0 million primarily due to recently approved rate adjustments that include a return on significant capital investments, partially offset by lower volumes resulting from the termination of power sales contracts upon a customer's purchase of an ownership interest in Wygen III in 2010.

Operations and maintenance increased $2.5 million primarily due to an increase in labor and employee benefit costs and increased allocation of corporate costs.

Depreciation and amortization increased $2.7 million primarily due to depreciation commencing on Wygen III and a higher asset base.

Interest expense, net increased $3.3 million due to due to higher debt balances associated with recent capital investments.

Other income decreased $2.1 million primarily due to decreased AFUDC-equity which ceased with the commencement of commercial operation of our Wygen III facility.

Income tax expense: The effective tax rate was comparable to the same period in the prior year.

Gas Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Revenue:				
Natural gas — regulated	$93,598	$79,727	$316,630	$315,182
Other — non-regulated services	6,324	7,388	13,558	15,103
Total revenue	99,922	87,115	330,188	330,285
Cost of sales:				
Natural gas — regulated	49,956	39,324	199,459	202,751
Other — non-regulated services	3,154	3,754	6,780	7,772
Total cost of sales	53,110	43,078	206,239	210,523
Gross margin	46,812	44,037	123,949	119,762
Operations and maintenance	28,249	32,091	62,809	66,449
Gain on sale of operating assets	—	—	—	(2,683)
Depreciation and amortization	5,947	6,774	11,968	13,819
Total operating expenses	34,196	38,865	74,777	77,585
Operating income (loss)	12,616	5,172	49,172	42,177
Interest expense, net	(6,339)	(6,824)	(13,311)	(13,009)
Other expense	124	260	149	49
Income tax benefit (expense)	(1,961)	506	(12,307)	(10,605)
Net income (loss)	$4,440	$(886)	$23,703	$18,612

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

Revenue (in thousands)	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Residential:				
Colorado	$10,749	$10,597	$33,735	$33,449
Nebraska	20,663	16,676	79,062	73,770
Iowa	18,593	14,896	66,024	63,575
Kansas	10,568	10,585	38,521	43,929
Total Residential	60,573	52,754	217,342	214,723
Commercial:				
Colorado	2,182	2,239	6,815	7,228
Nebraska	6,385	5,250	26,303	26,660
Iowa	7,802	6,224	28,685	29,013
Kansas	2,944	3,054	12,240	14,304
Total Commercial	19,313	16,767	74,043	77,205
Industrial:				
Colorado	583	249	698	293
Nebraska	163	636	336	2,141
Iowa	407	272	1,144	1,183
Kansas	6,849	3,548	7,969	4,335
Total Industrial	8,002	4,705	10,147	7,952
Transportation:				
Colorado	179	170	507	451
Nebraska	2,072	1,924	6,431	6,573
Iowa	827	758	2,152	1,958
Kansas	1,125	1,046	3,192	2,984
Total Transportation	4,203	3,898	12,282	11,966
Other:				
Colorado	25	29	56	56
Nebraska	511	484	1,119	1,096
Iowa	193	138	319	582
Kansas	778	952	1,322	1,602
Total Other	1,507	1,603	2,816	3,336
Total Regulated	93,598	79,727	316,630	315,182
Other - non-regulated Services	6,324	7,388	13,558	15,103
Total Revenue	$99,922	$87,115	$330,188	$330,285

Gross Margin (in thousands)	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Residential:				
Colorado	$3,760	$3,965	$9,880	$10,555
Nebraska	10,464	9,714	29,381	26,050
Iowa	10,313	8,620	26,594	24,075
Kansas	6,120	6,075	16,198	16,292
Total Residential	30,657	28,374	82,053	76,972
Commercial:				
Colorado	613	693	1,645	1,910
Nebraska	2,136	2,039	6,976	7,178
Iowa	2,433	2,016	6,596	6,629
Kansas	1,189	1,200	3,725	3,780
Total Commercial	6,371	5,948	18,942	19,497
Industrial:				
Colorado	127	68	163	91
Nebraska	41	71	91	234
Iowa	48	33	138	118
Kansas	761	480	992	663
Total Industrial	977	652	1,384	1,106
Transportation:				
Colorado	178	170	506	451
Nebraska	2,072	1,924	6,431	6,573
Iowa	827	758	2,152	1,958
Kansas	1,125	1,046	3,192	2,997
Total Transportation	4,202	3,898	12,281	11,979
Other:				
Colorado	25	29	56	56
Nebraska	511	483	1,119	1,095
Iowa	193	139	319	583
Kansas	706	880	1,017	1,143
Total Other	1,435	1,531	2,511	2,877
Total Regulated	43,642	40,403	117,171	112,431
Other - non-regulated Services	3,170	3,634	6,778	7,331
Total Gross Margin	$46,812	$44,037	$123,949	$119,762

Volumes Sold (in Dth)	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Residential:				
Colorado	1,127,379	1,150,169	3,847,384	3,971,016
Nebraska	1,772,388	1,384,365	7,842,625	7,720,752
Iowa	1,607,488	1,200,114	6,920,778	6,594,008
Kansas	818,677	836,716	4,249,556	4,405,333
Total Residential	5,325,932	4,571,364	22,860,343	22,691,109
Commercial:				
Colorado	253,822	269,435	835,518	924,808
Nebraska	748,867	652,800	3,091,977	3,197,924
Iowa	1,042,988	799,463	3,888,734	3,707,567
Kansas	324,680	343,704	1,627,611	1,688,852
Total Commercial	2,370,357	2,065,402	9,443,840	9,519,151
Industrial:				
Colorado	99,708	45,902	115,322	49,656
Nebraska	22,946	117,670	36,194	337,640
Iowa	68,662	46,235	178,463	177,501
Kansas	1,312,270	706,933	1,508,598	817,557
Total Industrial	1,503,586	916,740	1,838,577	1,382,354
Transportation:				
Colorado	183,494	176,676	528,665	475,219
Nebraska	6,688,435	5,558,285	12,636,481	13,548,913
Iowa	4,026,034	3,944,164	9,579,099	9,256,912
Kansas	2,940,539	3,092,475	7,380,809	7,302,303
Total Transportation	13,838,502	12,771,600	30,125,054	30,583,347
Other:				
Colorado	—	—	—	—
Nebraska	—	173	—	1,149
Iowa	—	10,232	—	52,529
Kansas	17,081	11,844	62,066	70,853
Total Other	17,081	22,249	62,066	124,531
Total Volumes Sold	23,055,458	20,347,355	64,329,880	64,300,492

	Three Months Ended June 30, 2011			Six Months Ended June 30, 2011		
Heating Degree Days:	Actual	Variance From Normal		Actual	Variance From Normal	
Colorado	840	(11	)%	3,601	(6	)%
Nebraska	585	2	%	3,866	2	%
Iowa	851	7	%	4,545	1	%
Kansas*	406	(10	)%	3,031	1	%
Combined Gas Utilities Heating Degree Days	660	—	%	3,872	—	%

	Three Months Ended June 30, 2010			Six Months Ended June 30, 2010		
Heating Degree Days:	Actual	Variance From Normal		Actual	Variance From Normal	
Colorado	856	(9.7	)%	3,693	(3.0	)%
Nebraska	495	(13.3	)%	3,867	3.0	%
Iowa	556	(29.9	)%	4,081	(8.0	)%
Kansas*	427	(4.9	)%	3,118	4.0	%
Combined Gas Utilities Heating Degree Days	544	(17.0	)%	3,747	(1.0	)%

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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, the winter heating season begins around November 1 and ends around March 31.

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010. Net income for the Gas Utilities segment was $4.4 million for the three months ended June 30, 2011 compared to Net loss of $0.9 million for the three months ended June 30, 2010 as a result of:

Gross margin increased $2.8 million primarily due to recently approved rate adjustments and cooler weather than in the same period in the prior year.

Operations and maintenance decreased $3.8 million primarily due to lower property tax expense including an $0.8 million credit from a recent settlement on assessments from prior tax years, overall efficiencies and lower allocation of corporate costs.

Depreciation and amortization decreased $0.8 million primarily due to a shift in corporate allocations as a result of higher asset deployment at the Electric Utilities.

Interest expense, net decreased $0.5 million primarily due to increased interest income on intercompany lending.

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

Income tax benefit (expense): The effective tax rate decreased for the three months ended June 30, 2011 was impacted by a favorable adjustment related to a state net operating loss true-up.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010. Net income for the Gas Utilities segment was $23.7 million for the six months ended June 30, 2011 compared to Net income of $18.6 million for the six months ended June 30, 2010 as a result of:

Gross margin increased $4.2 million primarily due to recently approved rate adjustments and cooler weather than in the same period in the prior year.

Operations and maintenance decreased $3.6 million primarily due to lower property tax expense including an $0.8 million credit from a recent settlement on assessment from prior tax years, and allocation of corporate costs.

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

Depreciation and amortization decreased $1.9 million primarily due to 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) was comparable to the same period in the prior year.

Income tax expense: The effective tax rate for the six months ended June 30, 2011 was comparable to the same period in the prior year.

Regulatory Matters — Utilities Group

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

							Approved Capital Structure	
	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved	Return on Equity	Equity	Debt
Nebraska Gas (1)	Gas	12/2009	9/2010	$12.1	$8.3	10.1 %	52.0 %	48.0 %
Iowa Gas (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	6/2010	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 has filed appeals

which have been denied. The Public Advocate currently has a filed 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 we made in our gas distribution system and other expense increases incurred since December 2008. Interim rates, subject to refund, equal to a $2.6 million increase, or 1.6%, in revenues went into effect on June 18, 2010. In August 2010, we reached a settlement with the OCA for a revenue increase of $3.4 million and hearings on the settlement were held in October 2010. Approval from the IUB 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 filed on Form 10-K.

(4) In January 2011, Black Hills Power filed a request with the SDPUC for approval of an Environmental Improvement Adjustment tariff pursuant to state legislation for tariff mechanisms to recover eligible investments and expenses related to new environmental measures. 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 Hill 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, $1.1 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. A hearing on the rate case with the CPUC has been scheduled for late October 2011.

Non-regulated Energy Group

We report four segments within our Non-regulated 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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Revenue	$18,838	$18,658	$36,744	$38,401
Operations and maintenance	10,187	10,499	20,754	20,233
Depreciation, depletion and amortization	7,602	6,842	14,923	12,953
Total operating expenses	17,789	17,341	35,677	33,186
Operating income (loss)	1,049	1,317	1,067	5,215
Interest expense	(1,389)	(1,391)	(2,772)	(2,173)

Other income	88	239	(97)	542
Income tax (expense) benefit	173	56	1,008	(1,015)
Net income (loss)	$(79)	$221	$(794)	$2,569

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Fuel production:				
Bbls of oil sold	100,901	84,427	204,451	168,818
Mcf of natural gas sold	2,247,381	2,356,674	4,382,039	4,508,850
Mcf equivalent sales	2,852,787	2,863,236	5,608,745	5,521,758

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Average price received: (a)				
Gas/Mcf (b)	$4.29	$4.85	$4.47	$5.36
Oil/Bbl	$79.53	$89.98	$73.10	$82.19
Depletion expense/Mcfe	$2.40	$2.15	$2.38	$2.08

(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 June 30, 2011				Three Months Ended June 30, 2010			
	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.21	$0.35	$0.55	$2.11	$1.32	$0.31	$0.54	$2.17
Piceance	0.83	0.76	(0.36	) 1.23	0.38	0.62	0.27	1.27
Powder River	1.42	—	1.38	2.80	1.00	—	1.02	2.02
Williston	0.50	—	1.48	1.98	2.42	—	1.70	4.12
All other properties	1.23	—	0.04	1.27	0.95	—	0.34	1.29
Total weighted average	$1.15	$0.23	$0.63	$2.01	$1.09	$0.20	$0.60	$1.89

	Six Months Ended June 30, 2011				Six Months Ended June 30, 2010			
	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.23	$0.41	$0.55	$2.19	$1.36	$0.34	$0.63	$2.33
Piceance	0.76	0.78	(0.06	) 1.48	0.45	0.72	0.32	1.49
Powder River	1.36	—	1.33	2.69	1.17	—	1.07	2.24
Williston	0.38	—	1.49	1.87	1.51	—	1.28	2.79
All other properties	1.43	—	0.21	1.64	1.07	—	0.25	1.32
Total weighted average	$1.17	$0.25	$0.68	$2.10	$1.17	$0.22	$0.63	$2.02

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010. Net loss for the Oil and Gas segment was $0.1 million for the three months ended June 30, 2011 compared to Net income of $0.2 million for the same period in 2010 as a result of:

Revenue increased $0.2 million primarily due to a 20% increase in oil volumes largely related to production in our ongoing Bakken drilling program in North Dakota, partially offset by a 12% lower average hedged oil price received. The decrease in crude oil price was influenced by fixed price swaps previously entered into at prices significantly below current oil market prices. Natural gas volumes, exclusive of gas liquids, were 4% lower than the prior period and the natural gas average hedged price decreased 12%.

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

Depreciation, depletion and amortization increased $0.8 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, net was comparable to the same period in the prior year.

Other income decreased due to lower earnings from equity investments.

Income tax (expense) benefit: The effective tax rate in the second quarter of 2011 was impacted by the tax benefit generated by percentage depletion.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010. Net loss for the Oil and Gas segment was $0.8 million for the six months ended June 30, 2011 compared to a Net income of $2.6 million for the same period in 2010 as a result of:

Revenue decreased $1.7 million due to a 17% decrease in the average hedged price of natural gas and an 11% decrease in the average hedged price of oil, as well as a 3% decline in gas volumes, exclusive of gas liquids, partially offset by a 21% increase in oil volumes. The decrease in average crude oil prices 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 $2.0 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 $0.6 million primarily due to higher interest rates.

Other income decreased $0.6 million due to lower earnings from equity investments.

Income tax (expense) benefit: The effective tax rate for the six months ended June 30, 2011 was positively impacted by a $0.3 million credit for research and development credits.

Coal Mining

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Revenue	$15,540	$15,049	$31,035	$29,029
Operations and maintenance	13,011	9,050	27,583	19,291
Depreciation, depletion and amortization	4,595	3,321	9,213	6,211
Total operating expenses	17,606	12,371	36,796	25,502
Operating income	(2,066)	2,678	(5,761)	3,527
Interest income, net	936	787	1,896	1,105
Other income	549	527	1,118	1,083
Income tax benefit (expense)	200	(918)	1,068	(1,295)
Net income (loss)	$(381)	$3,074	$(1,679)	$4,420

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Tons of coal sold	1,235	1,459	2,605	2,851
Cubic yards of overburden moved	2,933	3,752	6,388	7,323

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010. Net loss for the Coal Mining segment was $0.4 million for the three months ended June 30, 2011 compared to Net income of $3.1 million for the same period in 2010, as a result of:

Revenue increased $0.5 million primarily due to a 22% increase in average sales price per ton. The higher average sales price reflects the impact of price escalators and adjustments in certain of our sales contracts where we are able to pass a portion of higher mining costs to our customers. Approximately 40% of our coal production is sold under these regulated sales contracts where the sales price escalates based on actual mining cost increases. Most of our remaining production is sold under contracts where the sales price may escalate with published indices, which may not necessarily represent changes in actual mining costs. Revenue was also impacted during the current quarter by 15% lower volumes, primarily due to customer plant outages, plant closures and weather conditions which restricted our ability to mine coal.

Operations and maintenance increased $4.0 million which reflects the current phase of our mine where we have longer haul distances and higher stripping costs. Additionally, we experienced higher costs associated with drilling and blasting, equipment maintenance, fuel, staffing levels for our train load-out facility and weather conditions. 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 $1.3 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 June 30, 2010 was impacted by a tax benefit generated by percentage depletion.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010. Net loss for the Coal Mining segment was $1.7 million for the six months ended June 30, 2011 compared to Net income of $4.4 million for the same period in 2010 as a result of:

Revenue increased $2.0 million primarily due to a 17% increase in average sales price received per ton. The higher average sales price reflects the impact of price escalators and adjustments in certain of our sales contracts where we are able to pass a portion of higher mining costs to our customers. Approximately 40% of our coal production is sold under these regulated sales contracts where the sales price escalates based on actual mining cost increases. Most of our remaining production is sold under contracts where the sales price may escalate with published indices, which may not necessarily represent changes in actual mining costs. The increase in price received per ton during the quarter was partially offset by 9% lower volumes primarily due to customer plant outages, plant closures, and weather conditions which restricted our ability to mine coal.

Operations and maintenance costs increased $8.3 million which reflects the current phase of our mine where we have longer haul distances and higher overburden stripping costs. Additionally, we experienced higher costs associated with drilling and blasting, equipment maintenance, 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, which is 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 $3.0 million primarily related to reclamation costs and increased depreciation on equipment.

Interest income, net increased $0.8 million primarily due to increased lending to affiliates and higher interest rates earned.

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

Income tax benefit (expense): Income tax benefit (expense) reflects lower pre-tax earnings and a higher effective income tax rate, which for the period ended June 30, 2010 was favorably impacted by a tax benefit generated by percentage depletion.

Energy Marketing

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Gross margin —				
Realized gross margin	$1,193	$2,645	$6,450	$14,698
Unrealized gross margin	11,283	6,250	8,491	3,969
Total gross margin	12,476	8,895	14,941	18,667
Operating expenses	6,574	6,032	12,331	11,458

Depreciation and amortization	144	127	283	259
Total operating expenses	6,718	6,159	12,614	11,717
Operating income	5,758	2,736	2,327	6,950
Interest expense, net	(205)	(800)	(657)	(1,562)
Other income (expense)	3	184	2	153
Income tax (expense) benefit	(1,861)	(793)	(618)	(2,021)
Net income (loss)	$3,695	$1,327	$1,054	$3,520

Gross margin by commodity (in thousands):

	Three Months Ended Natural Gas	Crude Oil	Coal (a)	Power (a)	Environmental (a)	Total
June 30, 2011						
Realized	$(1,378)	$2,277	$530	$(236)	$—	$1,193
Unrealized	4,739	1,857	1,714	2,854	119	11,283
Total	$3,361	$4,134	$2,244	$2,618	$119	$12,476
June 30, 2010						
Realized	$2,046	$1,042	$(443)	$—	$—	$2,645
Unrealized	44	2041	4,165	—	—	6,250
Total	$2,090	$3,083	$3,722	$—	$—	$8,895

	Six Months Ended Natural Gas	Crude Oil	Coal (a)	Power (a)	Environmental (a)	Total
June 30, 2011						
Realized	$3,910	$2,535	$1,606	$(1,601)	$—	$6,450
Unrealized	1,262	(124)	3,363	3,871	119	8,491
Total	$5,172	$2,411	$4,969	$2,270	$119	$14,941
June 30, 2010						
Realized	$12,567	$2,574	$(443)	$—	$—	$14,698
Unrealized	(960)	764	4,165	—	—	3,969
Total	$11,607	$3,338	$3,722	$—	$—	$18,667

(a) Coal marketing activity began June 1, 2010, Power marketing began late in the third quarter of 2010, and Environmental marketing which 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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Natural gas physical sales — MMBtus	1,524,897	1,348,887	1,626,973	1,549,913
Crude oil physical sales — Bbls	23,257	20,935	22,255	17,203
Coal physical sales — Tons (a)	33,693	27,972	35,105	27,972
Power - MWh (a)	104	—	52	—

(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. Such gas is being held in inventory to capture the price differential between the time at which it was purchased and a subsequent sales date. Quantities held were as follows:

	As of June 30, 2011	As of December 31, 2010	As of June 30, 2010
Natural gas (MMBtu)	6,257,284	14,922,353	16,289,903
Crude oil (Bbl)	154,998	198,052	118,000
Coal (Ton)	46,700	1,529	—

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010. Net income for the Energy Marketing segment was $3.7 million for the three months ended June 30, 2011 compared to a Net income of $1.3 million for the same period in 2010 as a result of:

Gross margin increased $3.6 million primarily due to higher unrealized marketing margins of $5.0 million. This increase was driven by timing of natural gas settlements of $4.7 million and increased margins of $2.9 million from the Company’s portfolio of power marketing contracts partially offset by decreased unrealized margins from the coal portfolio of $2.5 million. The unrealized marketing gains were partially offset by lower realized marketing margins of $1.5 million. A less favorable natural gas market contributed to this variance. Natural gas volumes marketed increased 13%, crude oil volumes marketed increased 11% and coal marketing volumes increased 20%.

Operating expenses increased $0.5 million primarily due to higher compensation and benefit expenses relating to additional staff marketing new commodities and new geographic regions and a higher provision for compensation related to increased margins.

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

Interest expense, net decreased $0.6 million primarily due to changes in affiliate borrowings and decreased costs related to the committed Enserco Credit Facility.

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 June 30, 2011 was comparable to the same period in the prior year.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010. Net income for the Energy Marketing segment was $1.1 million for the six months ended June 30, 2011 compared to a Net income of $3.5 million for the same period in 2010 as a result of:

Gross margin decreased $3.7 million primarily driven by lower realized marketing margins of $8.2 million partially offset by an increase of $4.5 million in unrealized marketing margins. The decrease in realized marketing margins primarily reflected lower natural gas margins. Unrealized marketing gains include margins from power marketing activities of $3.9 million, which began in September, 2010 and unrealized gains of $2.2 million from natural gas partially offset by lower margins from crude oil and coal.

Operating expenses increased $0.9 million primarily due to 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 decreased $0.9 million primarily due to changes in affiliate borrowings and decreased costs related to the committed Enserco Credit Facility.

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

Income tax (expense) benefit: The effective tax rate for the six months ended June 30, 2011 was comparable to the six months ended June 30, 2010.

Power Generation

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Revenue	$7,780	$6,679	$15,400	$14,747
Operating, general and administrative costs	4,091	5,191	8,279	8,565
Depreciation and amortization	1,040	1,298	2,104	2,326
Gain on sale of operating asset	—	—	—	—
Total operating expense (income)	5,131	6,489	10,383	10,891
Operating income	2,649	190	5,017	3,856
Interest expense, net	(1,835)	(1,986)	(3,626)	(3,983)
Other (expense) income	21	1,171	1,225	1,160
Income tax (expense) benefit	(287)	209	(882)	(369)
Net income (loss)	$548	$(416)	$1,734	$664

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Contracted power plant fleet availability:				
Coal-fired plant	99.5%	98.9%	99.8%	99.5%
Natural gas-fired plants	100.0%	100.0%	100.0%	100.0%
Total availability	99.7%	99.3%	99.8%	99.7%

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

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010. Net income for the Power Generation segment was $0.5 million for the three months ended June 30, 2011 compared to Net loss of $0.4 million for the same period in 2010 as a result of:

Revenue increased $1.1 million primarily due to increased sales from Wygen I, which incurred a forced outages and a major overhaul in the same period in the prior year.

Operations and maintenance decreased $1.1 million primarily as costs were incurred in the same period in the prior year related to the forced outage and major overhaul of Wygen I.

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 $1.2 million due to lower earnings from our partnership investments.

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

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010. Net income for the Power Generation segment was $1.7 million for the six months ended June 30, 2011 compared to $0.7 million for the same period in 2010 as a result of:

Revenue increased $0.7 million primarily due to increased sales from Wygen I, which incurred a forced outages and a major overhaul in the same period in the prior year.

Operations and maintenance decreased $0.3 million primarily as higher costs were incurred in the same period in the prior year related to the forced outage and major overhaul of Wygen I.

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 was comparable to the same period in the prior year.

Income tax expense: The effective tax rate for the six months ended June 30, 2011 was comparable to the same period in the prior year.

Corporate

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010. Net loss for Corporate was $9.1 million for the three months ended June 30, 2011 compared to Net loss of $19.2 million for the three months ended June 30, 2010 as a result of an unrealized net, non-cash mark-to-market loss for the quarter ended June 30, 2011 of approximately $7.8 million on certain interest rate swaps compared to a $24.9 million unrealized mark-to-market non-cash loss on these interest rate swaps in the prior year.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010. Net loss for Corporate was $8.2 million compared to Net loss of $24.1 million as a result of an unrealized net, mark-to-market losses for the six months ended June 30, 2011 of approximately $2.4 million on certain interest rate swaps compared to a $28.0 million unrealized mark-to-market non-cash loss on these interest rate swaps in the prior year.

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 six months ended June 30, 2011 and 2010 (in thousands):

Cash provided by (used in):	2011	2010
Operating activities	$182,017	$143,990
Investing activities	$(225,064)	$(163,021)

Financing activities	$98,682	$(29,837)

2011 Compared to 2010

Operating Activities

Net cash provided by operating activities was $38.0 million higher for the six months ended June 30, 2011than in the same period in 2010 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $28.1 million higher for the six months ended June 30, 2011 than for the same period the prior year.

- Net inflows from operating assets and liabilities were $52.9 million for the six months ended June 30, 2011, which is an increase of $18.3 million from the same period in the prior year as a result of:

- Net inflows from working capital accounts were $9.3 million for the six months ended June 30, 2011, which is a decrease of $14.7 million from the prior year net inflows from working capital accounts. In addition to normal working capital changes and seasonality of our gas utility operations, 2011 reflects increased cash inflows from higher withdrawals of gas storage inventories by Energy Marketing. Energy Marketing also experienced higher outflows in the current period related to higher margin posted on marketing transactions; and

- Inflows from changes in regulatory assets and regulatory liabilities, primarily related to collection of gas costs by our Gas Utilities.

Investing Activities

Net cash used in investing activities was $62.0 million more for the six months ended June 30, 2011 than in the same period in 2010 reflecting higher capital additions. During 2011, cash outflows for property, plant and equipment additions totaled $225.9 million, including the partial 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 oil and gas property maintenance capital and development drilling.

Financing Activities

Net cash provided by financing activities was $128.5 million more for the six months ended June 30, 2011 than in the same period in 2010 primarily due to increased borrowings to finance our construction program. During the six months ended June 30, 2011, we borrowed an additional $150 million on a new corporate term loan which was used to pay down a portion of our Revolving Credit Facility, paid $4.1 million of long-term debt primarily related to required payments on the Black Hills Wyoming Project Financing, and paid $29.5 million of cash dividends on common stock.

Dividends

Dividends paid on our common stock totaled $29.5 million for the six months ended June 30, 2011, or $0.73 per share. On July 27, 2011, our Board of Directors declared an additional quarterly dividend of $0.365 per share payable September 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 June 30, 2011, we had approximately $88 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 June 30, 2011, we had borrowings of $130 million and letters of credit outstanding of $43 million on our Revolving Credit Facility. Available capacity remaining on our Revolving Credit Facility was approximately $327.0 million at June 30, 2011.

Our consolidated net worth was $1,108.1 million at June 30, 2011, which was approximately $231.5 million in excess of the net worth we were required to maintain under the Revolving Credit Facility. At June 30, 2011, our long-term debt ratio was 51.6%, our total debt leverage ratio (long-term debt and short-term debt) was 58.6%, and our recourse leverage ratio was approximately 59.3%.

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.

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 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 June 30, 2011

At June 30, 2011, $118.7 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 (1.44% at June 30, 2011). The covenants are substantially the same as those included in the Revolving Credit Facility and we were in compliance with these covenants as of June 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. The cost of borrowing under this Term Loan was based on a spread of 137.5 basis points over LIBOR (1.56% at June 30, 2011). The covenants are substantially the same as those included in the Revolving Credit Facility and we were in compliance with these covenants as of June 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 shareholders is derived from these cash flows. As a result of certain statutory limitations or regulatory or financing agreements, we could have restrictions on the amount of distributions allowed to be made by our subsidiaries.

- Our utility subsidiaries are generally limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of June 30, 2011, the restricted net assets at our Electric and Gas Utilities were approximately $207.3 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 June 30, 2011 were $153.1 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 and long-term financings. We intend to settle the equity forward in the fourth quarter of 2011. We may complete an additional long-term senior unsecured debt financing at the holding company level in late 2011 or 2012. We intend to maintain a consolidated debt-to-capitalization level in the range of 50% to 55%; however, during the construction period of our new generation facilities in Colorado, we may exceed this level on a temporary basis.

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").

Based on the closing Black Hills Corporation common stock price of $30.09 on June 30, 2011, and the forward price on that date for the equity forward of $27.92 and over-allotment shares of $27.92, the fair value net cash settlement of the 4,000,000 equity forward instrument and 413,519 over-allotment shares was approximately $10 million. The Forward Agreements require a 60 day notice prior to settlement for cash or net share settlements. Forward prices and volume-weighted average market prices for the period between when notice is provided and settlement are used to calculate cash and net share settlement amounts.

At June 30, 2011, the equity forward instrument could have been settled with physical delivery of 4,413,519 shares to J.P. Morgan in exchange for cash of $123.2 million. Assuming required notices were given and actions taken, the forward instruments could have also been net settled at June 30, 2011 with delivery of cash of approximately $9.6

million or approximately 331,000 shares of common stock to J.P. Morgan. We may settle the equity forward instrument at any time up to the maturity date of November 10, 2011. We may also unilaterally elect to cash or net share settle at any date up to maturity, for all or a portion of the equity forward shares. It is our intent to settle the equity forward with the physical delivery of shares in the fourth quarter of 2011.

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 six months ended June 30, 2011, respectively, we recorded a $7.8 million and $2.4 million pre-tax unrealized mark-to-market non-cash loss on the swaps. The mark-to-market value on these swaps was a liability of $56.3 million at June 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 $0.3 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 have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly as they relate to our planned capital requirements to build gas-fired power generation facilities to serve our Colorado Electric customers, and because of our upcoming holding company debt maturities, which are $225 million and $250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at their fair value prior to their mandatory early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair values on the termination dates.

In addition, we have $150 million notional amount floating-to-fixed interest rate swaps, having a maximum remaining term of 5.5 years. These swaps have been designated as cash flow hedges and accordingly, their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the accompanying Condensed Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $22.7 million at June 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 stand-alone Enserco Credit Facility and advances of cash from the parent company.

In our Energy Marketing segment, our largest counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize credit risk through an evaluation of 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 marketing business in the near term.

Credit Ratings

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing, and vendor payment terms, including collateral requirements. As of June 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 June 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

* In May 2011, Fitch downgraded our corporate credit rating from BBB to BBB-. The Black Hills Power credit rating remained unchanged.

Capital Requirements

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

	Expenditures for the Six Months Ended June 30, 2011	Total 2011 Planned Expenditures	Total 2012 Planned Expenditures	Total 2013 Planned Expenditures
Utilities:				
Electric Utilities (1) (2) (3)	$99,795	$201,500	$284,300	$280,600
Gas Utilities	16,291	58,600	55,800	47,600
Non-regulated Energy:				
Oil and Gas (4)	22,313	67,500	61,500	93,300
Power Generation (5)	63,706	91,700	4,200	4,400
Coal Mining	5,237	12,500	16,000	16,700
Energy Marketing	2,651	2,400	3,400	3,400
Corporate	1,347	6,950	11,630	6,650
	$211,340	$441,150	$436,830	$452,650

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(1) The 2011 total planned expenditures include capital requirements associated with the on-going construction of 180 MW gas-fired power generation facility to serve our Colorado Electric customers. We spent $39.6 million during the first six months of 2011. The total construction cost of the facility is expected to be approximately $227 million and construction is expected to be completed by the end of 2011.

(2) Planned 2011 expenditures include expected spending of $5.4 million for a planned wind project for Colorado Electric, subject to CPUC approval. Planned 2011 expenditures reflect the cancellation of the wind project at Black Hills Power.

(3) Planned expenditures for 2012 and 2013 have been updated from our 2010 Annual Report filed on Form 10-K to include (a) $34.4 million for 2012 and $87.4 million for 2013 for new generation and transmission at Cheyenne Light for which a CPCN was filed on August 1, 2011 that is subject to acceptance of the CPCN and air permits, (b) approximately $21.1 million for 2012 for our 50% share of the Colorado Electric wind project, subject to CPUC approval, (c) $43.0 million and $54.3 million, respectively, for 2012 and 2013 for the 88 MW utility owned gas-fired generation at Colorado Electric, also subject to CPUC approval, and (d) $14.6 million additional transmission for Colorado Electric

(4) Oil and Gas planned expenditures have increased $18.6 million from our planned expenditures disclosed in our 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 $63.5 million during the first six 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 $3.4 million from $83.5 million at December 31, 2010 to $80.1 million at June 30, 2011. Approximately $46.9 million of the firm transportation and storage fee obligations relate to the 2011-2013 period with the remaining occurring thereafter.

Construction of a 180 MW power generation facility by our Colorado Electric utility and 200 MW power generation facility by our Power Generation segment is progressing. Cost of construction is expected to be approximately $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 June 30, 2011, committed contracts for equipment purchases and for construction were 100% and 95% complete, respectively, for the Colorado Electric utility and 100% and 94% complete, respectively, for the Power Generation segment.

As part of its plan to meet Colorado's Renewable Energy Standard, Colorado Electric filed a proposal in March 2011 with the CPUC to rate base 50% ownership in a 29 MW wind turbine project. On July 15, 2011, Colorado Electric signed a wind turbine supply agreement with Vestas-American Wind Technologies, Inc. for $33.3 million. Our 50% share of the project is expected to cost approximately $27.0 million and is expected to begin serving Colorado Electric customers no later than December 31, 2012. The proposal is pending with the CPUC.

Guarantees

Except as noted below, there have been no new guarantees provided from those previously disclosed in Note 20 of our Notes to the Consolidated Financial Statements in our 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 counterpart.

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

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

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

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

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

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

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

- We expect contributions to our defined benefit pension plans to be approximately $10.0 million and $13.4 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' ability to generate sufficient stable cash flow over an extended period of time.

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

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

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

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

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

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

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

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

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

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

	June 30, 2011	December 31, 2010	June 30, 2010
Net derivative (liabilities) assets	$(3,441)	$(7,188)	$(6,045)
Cash collateral	6,254	10,355	9,551
	$2,813	$3,167	$3,506

Non-Regulated Trading Activities

The following table provides a reconciliation of Energy Marketing 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 six months ended June 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	918	
Unrealized gain (loss) on new positions entered during the period and still existing at June 30, 2011	26,288	
Realized (gain) loss on positions that existed at December 31, 2010 and were settled during the period	(9,422	)
Change in cash collateral	(2,708	)
Unrealized gain (loss) on positions that existed at December 31, 2010 and still exist at June 30, 2011	(10,414	)
Total fair value of energy marketing positions at June 30, 2011	$28,080	(a)

(a) The fair value of energy 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):

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

To value the assets and liabilities for our outstanding derivative contracts, we use the fair value methodology outlined in accounting standards for fair value measurements and disclosures. 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	$1,184		$66	$1,250	
Level 1	—		—	—	
Level 2	13,142		7,958	21,100	
Level 3	2,475		3,840	6,315	
Market value adjustment for inventory (see footnote (a) above)	(585	)	—	(585	)
Total fair value of our energy marketing positions	$16,216		$11,864	$28,080	

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

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

Fair value of our energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$28,080	
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	(13,281	)
Fair value of all forward positions (non-GAAP)	14,799	
Cash collateral included in GAAP marked-to-market fair value	(1,250	)
Fair value of all forward positions excluding cash collateral (non-GAAP) *	$13,549	

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

Except as discussed above, there have been no material changes in market risk from those reported in our 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 June 30, 2011 were as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)	Price
CIG	9/2/2009	Swap	07/11 - 09/11	500	$5.32
NWR	9/2/2009	Swap	07/11 - 09/11	500	$5.32
San Juan El Paso	9/2/2009	Swap	07/11 - 09/11	2,500	$5.54
CIG	9/25/2009	Swap	07/11 - 09/11	500	$5.59
NWR	9/25/2009	Swap	07/11 - 09/11	1,000	$5.59
AECO	9/25/2009	Swap	07/11 - 09/11	500	$5.76
San Juan El Paso	9/25/2009	Swap	07/11 - 09/11	5,000	$5.91
San Juan El Paso	10/23/2009	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	07/11 - 09/11	500	$5.19
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	9/2/2009	Swap	07/11 - 09/11	5,000	$75.10
NYMEX	9/2/2009	Put	07/11 - 09/11	5,000	$63.00
NYMEX	9/29/2009	Swap	07/11 - 09/11	5,000	$74.00
NYMEX	10/6/2009	Put	07/11 - 09/11	5,000	$65.00
NYMEX	10/9/2009	Swap	10/11 - 12/11	5,000	$79.35
NYMEX	10/23/2009	Put	10/11 - 12/11	5,000	$75.00
NYMEX	11/19/2009	Swap	07/11 - 09/11	1,500	$85.95
NYMEX	11/19/2009	Swap	10/11 - 12/11	5,000	$87.50
NYMEX	1/8/2010	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

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 June 30, 2011 we had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 5.5 years. These swaps have been designated as hedges in accordance with accounting standards for derivatives and hedges and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the 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 income statement. For the three months and six months ended June 30, 2011 we recorded pre-tax unrealized mark-to-market losses of $7.8 million and $2.4 million, respectively, For the three months and six months ended June 30, 2010 we recorded pre-tax unrealized mark-to-market losses of $24.9 million and $28.0 million, respectively. These swaps are 7.5 and 17.5 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.

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

June 30, 2011	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years *	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax Income (Loss)
Designated Interest rate swaps	$150,000	5.04%	5.50	$—	$—	$6,900	$15,788	$(22,688)	$—
De-designated Interest rate swaps	250,000	5.67%	0.50	—	—	56,342	—	—	(2,362)
	$400,000			$—	$—	$$63,242	$$15,788	$(22,688)	$(2,362)
December 31, 2010									
Designated Interest rate swaps	$150,000	5.04%	6.0	$—	$—	$ 6,823	$ 14,976	$ (21,799)	$—
De-designated Interest rate swaps	250,000	5.67%	1.0	—	—	53,980	—	—	(15,193)
	$400,000			$—	$—	$ 60,803	$ 14,976	$ (21,799)	$(15,193)
June 30, 2010									
Designated Interest rate swaps	$150,000	5.04%	6.50	$—	$—	$ 6,393	$ 17,551	$ (23,944)	$—
De-designated Interest rate swaps	250,000	5.67%	0.50	—	—	66,740	—	—	(27,953)
	$400,000			$—	$—	$ 73,133	$ 17,551	$ (23,944)	$(27,953)

* 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 7.5 years and de-designated swaps totaling $150 million terminate in 17.5 years.

Based on June 30, 2011 market interest rates and balances for our $150 million notional interest rate swaps, a loss of approximately $6.9 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 June 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 June 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

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.

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
April 1, 2011 - April 30, 2011	—	$—	—	—
May 1, 2011 - May 31, 2011	969	$34.61	—	—
June 1, 2011 - June 30, 2011	—	$—	—	—
Total	969	$34.61	—	—

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(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 our Wyodak Coal Mine, 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 June 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 June 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 June 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 June 30, 2011 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for each of our mining complexes. All citations were abated within 24 hours of issue.

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

ITEM 6. Exhibits

Exhibit 10.1	Credit Agreement dated June 24, 2011, among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, The Bank of Nova Scotia, as Administrative Agent, Co-Lead Arranger and Joint Book Runner, and U.S. Bank N.A. and CoBank, ACB as Co-Lead Arranger and Joint Book Runners (filed as exhibit to the Form 8-K filed on June 27, 2011 and incorporated by reference herein).
Exhibit 10.2	First Amendment to the Restoration Plan of Black Hills Corporation dated July 24, 2011.
Exhibit 10.3	First Amendment to the Independent Contractor Agreement between Black Hills Corporation and Lone Mountain Investments, Inc. dated July 27, 2011.
Exhibit 10.4	Seventh Amendment to Third Amendment and Restated Credit Agreement effective May 12, 2011, among Enserco Energy, Inc., as borrower, BNP Paribas, as administrative agent, collateral agent and the document agent, as an issuing bank, and a bank, Societe Generale, as an issuing bank, a bank and the syndication agent, and each of the other financial institutions which are parties thereto.
Exhibit 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.
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Exhibit 101	Financials for XBRL Format

BLACK HILLS CORPORATION

Signatures

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

BLACK HILLS CORPORATION

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

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

Dated: August 5, 2011

EXHIBIT INDEX

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