BLACK HILLS CORP /SD/
Form 10-Q
May 10, 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 March 31, 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 as of | April 29, 2011 |
|---|---|---|
| Common stock, $1.00 par value | 39,409,489 | shares |

TABLE OF CONTENTS

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) |
| Aquila | Aquila, Inc. |
| ASC | Accounting Standards Codification |
| ASC 820 | ASC 820, "Fair Value Measurements and Disclosures" |
| 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 that was formerly known as Black Hills Energy, Inc. |
| Black Hills Power | Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company |
| Black Hills Service Company | Black Hills Service Company, a direct wholly-owned subsidiary of the Company |
| Black Hills Utility Holdings | Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of the Company |
| Black Hills Wyoming | Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation |
| Btu | British thermal unit |
| CFTC | Commodities Futures and Trading Commission |
| Cheyenne Light | Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company |
| Colorado Electric | Black Hills Colorado Electric Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings |
| Colorado Gas | Black Hills Colorado Gas Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings |
| Colorado IPP | Black Hills Colorado IPP, a direct wholly-owned subsidiary of Black Hills Electric Generation |
| CPCN | Certificate of Public Convenience and Necessity |
| CPUC | Colorado Public Utilities Commission |
| De-designated interest rate swaps | The $250.0 million notional amount interest rate swaps that were originally designated as cash flow hedges under accounting for derivatives and hedges but subsequently de-designated in December 2008 |
| Dodd-Frank | Dodd-Frank Wall Street Reform and Consumer Protection Act |

3

| | |
|---|---|
| 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 4,000,000 million shares of Black Hills Corporation common stock |
| GAAP | Generally Accepted Accounting Principles |
| Global Settlement | Global 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 |
| 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 |
| MDU | MDU Resources Group, Inc. |
| MEAN | Municipal Energy Agency of Nebraska |
| MMBtu | One million British thermal units |
| MSHA | Mine Safety and Health Administration |
| MW | Megawatt |
| MWh | Megawatt-hour |
| Nebraska Gas | Black Hills Nebraska Gas Utility Company, LLC, (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings |
| NPSC | Nebraska Public Service Commission |
| NYMEX | New York Mercantile Exchange |
| OCA | Office of Consumer Advocate |
| PGA | Purchase Gas Adjustment |
| PPA | Power Purchase Agreement |
| PPACA | Patient Protection and Affordability Care Act |
| PSCo | Public Service Company of Colorado |
| Revolving Credit Facility | Our $500 million three-year revolving credit facility which commenced on April 15, 2010 and expires on April 14, 2013 |
| SDPUC | South Dakota Public Utilities Commission |
| SEC | United States Securities and Exchange Commission |
| WPSC | Wyoming Public Service Commission |
| WRDC | Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings |

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

| | Three Months Ended March 31, 2011 | 2010 |
|---|---|---|
| | (in thousands, except per share amounts) | |
| Operating revenues: | | |
| Utilities | $374,696 | $388,666 |
| Non-regulated energy | 28,604 | 37,834 |
| Total operating revenues | 403,300 | 426,500 |
| | | |
| Operating expenses: | | |
| Utilities - | | |
| Fuel, purchased power and cost of gas sold | 210,511 | 236,314 |
| Operations and maintenance | 67,409 | 65,034 |
| Gain on sale of operating assets | — | (2,683) |
| Non-regulated energy operations and maintenance | 29,211 | 22,960 |
| Depreciation, depletion and amortization | 31,987 | 28,395 |
| Taxes - property, production and severance | 8,218 | 6,477 |
| Other operating expenses | 251 | 301 |
| Total operating expenses | 347,587 | 356,798 |
| | | |
| Operating income | 55,713 | 69,702 |
| | | |
| Other income (expense): | | |
| Interest charges - | | |
| Interest expense (including amortization of debt issuance costs, premium and discount, realized settlements on interest rate swaps) | (29,735) | (25,120) |
| Allowance for funds used during construction - borrowed | 3,363 | 3,148 |
| Capitalized interest | 2,434 | 206 |
| Interest rate swaps - unrealized (loss) gain | 5,465 | (3,035) |
| Interest income | 560 | 246 |
| Allowance for funds used during construction - equity | 295 | 2,028 |
| Other income, net | 731 | 418 |
| Total other income (expense) | (16,887) | (22,109) |
| | | |
| Income (loss) from continuing operations before equity in earnings (loss) of unconsolidated subsidiaries and income taxes | 38,826 | 47,593 |
| Equity in earnings (loss) of unconsolidated subsidiaries | 993 | 317 |
| Income tax benefit (expense) | (12,909) | (16,476) |
| | | |
| Net income (loss) | $26,910 | $31,434 |
| | | |
| Weighted average common shares outstanding: | | |
| Basic | 39,059 | 38,848 |

| | | |
|---|---|---|
| Diluted | 39,761 | 39,009 |
| Total earnings (loss) per share - basic | $0.69 | $0.81 |
| Total earnings (loss) per share - diluted | $0.68 | $0.81 |
| Dividends paid per share of common stock | $0.365 | $0.360 |

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)

| | March 31, 2011 | December 31, 2010 | March 31, 2010 |
|---|---|---|---|
| | (in thousands) | | |
| ASSETS | | | |
| Current assets: | | | |
| Cash and cash equivalents | $44,016 | $32,438 | $136,023 |
| Restricted cash | 3,406 | 4,260 | 27,215 |
| Accounts receivable, net | 306,070 | 328,811 | 242,189 |
| Materials, supplies and fuel | 69,341 | 139,677 | 91,111 |
| Derivative assets, current | 49,295 | 56,572 | 54,773 |
| Income tax receivable, net | 23,665 | — | — |
| Deferred income tax assets, current | 18,362 | 17,113 | 5,610 |
| Regulatory assets, current | 36,834 | 66,429 | 42,876 |
| Other current assets | 60,804 | 25,571 | 26,189 |
| Total current assets | 611,793 | 670,871 | 625,986 |
| | | | |
| Investments | 17,088 | 17,780 | 18,466 |
| | | | |
| Property, plant and equipment | 3,461,559 | 3,359,762 | 3,045,126 |
| Less accumulated depreciation and depletion | (889,031) | (864,329) | (830,423) |
| Total property, plant and equipment, net | 2,572,528 | 2,495,433 | 2,214,703 |
| | | | |
| Other assets: | | | |
| Goodwill | 354,831 | 354,831 | 353,734 |
| Intangible assets, net | 4,011 | 4,069 | 4,248 |
| Derivative assets, non-current | 5,135 | 9,260 | 5,877 |
| Regulatory assets, non-current | 140,735 | 138,405 | 117,561 |
| Other assets, non-current | 20,907 | 20,860 | 18,064 |
| Total other assets | 525,619 | 527,425 | 499,484 |
| | | | |
| TOTAL ASSETS | $3,727,028 | $3,711,509 | $3,358,639 |

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)

| | March 31, 2011 | December 31, 2010 | March 31, 2010 |
|---|---|---|---|
| | (in thousands, except share amounts) | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | | |
| Current liabilities: | | | |
| Accounts payable | $217,559 | $279,069 | $194,342 |
| Accrued liabilities | 141,184 | 170,301 | 140,939 |
| Derivative liabilities, current | 91,139 | 79,167 | 68,834 |
| Accrued income taxes, net | — | 779 | 10,568 |
| Regulatory liabilities, current | 15,004 | 3,943 | 9,850 |
| Notes payable | 287,000 | 249,000 | 223,000 |
| Current maturities of long-term debt | 4,254 | 5,181 | 24,426 |
| Total current liabilities | 756,140 | 787,440 | 671,959 |
| | | | |
| Long-term debt, net of current maturities | 1,184,830 | 1,186,050 | 993,514 |
| | | | |
| Deferred credits and other liabilities: | | | |
| Deferred income tax liability, non-current | 303,647 | 277,136 | 270,079 |
| Derivative liabilities, non-current | 15,554 | 21,361 | 12,081 |
| Regulatory liabilities, non-current | 90,923 | 84,611 | 44,788 |
| Benefit plan liabilities | 128,170 | 124,709 | 144,199 |
| Other deferred credits and other liabilities | 134,617 | 129,932 | 114,021 |
| Total deferred credits and other liabilities | 672,911 | 637,749 | 585,168 |
| | | | |
| Stockholders' equity: | | | |
| Common stockholders' equity — | | | |
| Common stock $1 par value; 100,000,000 shares authorized; | | | |
| Issued 39,434,304; 39,280,048 and 39,178,067 shares, respectively | 39,434 | 39,280 | 39,178 |
| Additional paid-in capital | 601,021 | 598,805 | 593,589 |
| Retained earnings | 498,614 | 486,075 | 491,202 |
| Treasury stock at cost – 26,075; 10,962 and 4,284 shares, respectively | (762) | (309) | (112) |
| Accumulated other comprehensive loss | (25,160) | (23,581) | (15,859) |
| Total stockholders' equity | 1,113,147 | 1,100,270 | 1,107,998 |
| | | | |
| TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY | $3,727,028 | $3,711,509 | $3,358,639 |

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)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Operating activities: | (in thousands) | |
| Net income (loss) | $26,910 | $31,434 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 31,987 | 28,395 |
| Derivative fair value adjustments | 9,662 | (1,579) |
| Gain on sale of operating assets | — | (2,683) |
| Stock compensation | 2,370 | 989 |
| Unrealized mark-to-market loss (gain) on interest rate swaps | (5,465) | 3,035 |
| Deferred income taxes | 25,679 | 3,492 |
| Equity in (earnings) loss of unconsolidated subsidiaries | (993) | (317) |
| Allowance for funds used during construction - equity | (295) | (2,028) |
| Employee benefit plans | 3,642 | 3,940 |
| Other adjustments | (1,599) | 2,382 |
| Change in operating assets and liabilities: | | |
| Materials, supplies and fuel | 79,717 | 21,755 |
| Accounts receivable and other current assets | (35,605) | 24,044 |
| Accounts payable and other current liabilities | (73,302) | (24,716) |
| Regulatory assets | 33,966 | 3,277 |
| Regulatory liabilities | 9,984 | 2,834 |
| Other operating activities | 4,613 | (5,335) |
| Net cash provided by operating activities | 111,271 | 88,919 |
| Investing activities: | | |
| Property, plant and equipment additions | (122,544) | (81,290) |
| Proceeds from sale of ownership interest in operating assets | — | 6,105 |
| Other investing activities | 786 | (2,865) |
| Net cash used in investing activities | (121,758) | (78,050) |
| Financing activities: | | |
| Dividends paid | (14,371) | (14,089) |
| Common stock issued | 605 | 1,522 |
| Short-term borrowings - issuances | 210,000 | 108,500 |
| Short-term borrowings - repayments | (172,000) | (50,000) |
| Long-term debt - repayments | (2,155) | (33,217) |
| Other financing activities | (14) | (463) |
| Net cash provided by (used in) financing activities | 22,065 | 12,253 |
| Net change in cash and cash equivalents | 11,578 | 23,122 |
| Cash and cash equivalents beginning of period | 32,438 | 112,901 |
| Cash and cash equivalents end of period | $44,016 | $136,023 |

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 March 31, 2011, December 31, 2010 and March 31, 2010 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal and revenues from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market price. In particular, the normal peak usage season for gas utilities is November through March and significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three months ended March 31, 2011 and our financial condition as of March 31, 2011, December 31, 2010, and March 31, 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 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 revenues, (b) the categories of Fuel, purchased power and cost of gas sales and Operations and maintenance included in our Operating expenses have also been reclassified into utilities and non-regulated, and (c) the Taxes - property, production and severance line has been reclassified to show only those taxes. Any taxes other than income are now included in the respective utility or non-regulated operations and maintenance lines. 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 financial statements, the Company's management determined that certain intercompany transactions with our rate regulated operations had not been properly eliminated in consolidation, resulting in an overstatement of Utility and Non-regulated revenue and Fuel, purchased power and cost of gas sold of $15.8 million, in aggregate for the three months ended March 31, 2010, respectively. As such, the condensed consolidated financial statements have been restated for the correction of this error. The error did not have an impact on our gross margin, net income, total assets or cash flows.

9

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

Recently Adopted Accounting Standards

Fair Value Measurements, ASC 820

In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements, disclosure of inputs and techniques used in valuation and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements are required to be presented separately. These disclosures are required for interim and annual reporting periods and were effective for us on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which were effective on January 1, 2011. The guidance requires additional disclosures, but did not impact our financial position, results of operations or cash flows. The additional disclosures are included in Note 13.

Recently Issued Accounting Standards and Legislation

Patient Protection and Affordable Care Act

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

Dodd-Frank Wall Street Reform and Consumer Protection Act

In July 2010, the President of the United States signed into law comprehensive financial reform legislation under Dodd-Frank. Title VII of Dodd-Frank effectively regulates many derivative transactions in the United States that were previously unregulated, including swap transactions in the over-the-counter market. Among other things, Dodd-Frank (i) mandates the clearing of some swaps through regulated central clearing organizations and the trading of clearing swaps through regulated exchanges or swap execution facilities, in each case subject to certain key exemptions, and (ii) authorizes regulators to establish collateral and margin requirements for certain swap transactions that are not cleared. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users, potentially including utilities, and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. Significant rule-making by numerous governmental agencies, particularly the CFTC with respect to non-security commodities, will be required over the next several months to implement the restrictions, limitations, and requirements contemplated by Dodd-Frank, and we will continue to evaluate the impact as these rules become available.

(3) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Three Months Ended

| | March 31, 2011 | March 31, 2010 |
|---|---|---|
| | (in thousands) | |
| Non-cash investing activities— | | |
| Property, plant and equipment acquired with accrued liabilities | $32,419 | $23,473 |
| Cash (paid) refunded during the period for— | | |
| Interest (net of amounts capitalized) | $(11,817) | $(10,182) |
| Income taxes, net | $(24) | $44 |

10

(4) MATERIALS, SUPPLIES AND FUEL

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

| | March 31, 2011 | December 31, 2010 | March 31, 2010 |
|---|---|---|---|
| Materials and supplies | $34,341 | $31,749 | $32,200 |
| Fuel - Electric Utilities | 9,307 | 9,687 | 9,028 |
| Natural gas in storage — Gas Utilities | 2,199 | 21,691 | 4,868 |
| Gas and oil held by Energy Marketing* | 23,494 | 76,550 | 45,015 |
| Total materials, supplies and fuel | $69,341 | $139,677 | $91,111 |

* As of March 31, 2011, December 31, 2010 and March 31, 2010, market adjustments related to natural gas held by Energy Marketing and recorded in inventory as part of fair value hedge transactions were $0.3 million, $(9.1) million and $(11.0) million, respectively (see Note 12 for further discussion of Energy Marketing trading activities).

(5) ACCOUNTS RECEIVABLE

Trade Accounts Receivable

Our Accounts receivable represents primarily customer trade accounts at our Electric Utilities, Gas Utilities and counterparty trade accounts at our Energy Marketing segment. This balance fluctuates primarily due to the seasonality of our Gas Utilities and volumes and commodity prices at our Energy Marketing segment. We maintain an allowance for doubtful accounts which reflects our best estimate of potentially uncollectible trade accounts receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit-worthiness, the age of the accounts receivable balances and current economic conditions that may affect our ability to collect.

Following is a summary of receivables (in thousands):

| March 31, 2011 | Accounts Receivable, Trade | Unbilled Revenues | Total Accounts Receivable | Less Allowance for Doubtful Accounts | Accounts Receivable, net |
|---|---|---|---|---|---|
| Electric | $46,077 | $16,196 | $62,273 | $(728) | $61,545 |
| Gas | 58,665 | 21,620 | 80,285 | (1,763) | 78,522 |
| Oil and Gas | 7,503 | — | 7,503 | (161) | 7,342 |
| Coal Mining | 982 | — | 982 | — | 982 |
| Energy Marketing | 154,660 | — | 154,660 | (114) | 154,546 |
| Power Generation | 2,050 | — | 2,050 | — | 2,050 |
| Corporate | 1,083 | — | 1,083 | — | 1,083 |
| Total | $271,020 | $37,816 | $308,836 | $(2,766) | $306,070 |

| December 31, 2010 | Accounts Receivable, Trade | Unbilled Revenues | 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 |

| March 31, 2010 | Accounts Receivable, Trade | Unbilled Revenues | Total Accounts Receivable | Less Allowance for Doubtful Accounts | Accounts Receivable, net |
|---|---|---|---|---|---|
| Electric | $45,466 | $13,415 | $58,881 | $(1,346) | $57,535 |
| Gas | 60,076 | 19,977 | 80,053 | (2,877) | 77,176 |
| Oil and Gas | 6,144 | — | 6,144 | — | 6,144 |
| Coal Mining | 1,698 | — | 1,698 | — | 1,698 |
| Energy Marketing | 99,738 | — | 99,738 | (1,008) | 98,730 |
| Power Generation | 569 | — | 569 | — | 569 |
| Corporate | 337 | — | 337 | — | 337 |
| Total | $214,028 | $33,392 | $247,420 | $(5,231) | $242,189 |

Income Tax Receivable

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

(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 March 31, 2011, we were in compliance with these covenants. None of our facilities or debt securities contain default provisions pertaining to our credit ratings.

Revolving Credit Facility

In April 2010, we entered into a new $500.0 million Revolving Credit Facility expiring April 14, 2013. The facility contains an accordion feature which allows us to, with the consent of the administrative agent, increase the capacity of the facility to $600.0 million. This facility can be used for the issuance of letters of credit, to fund working capital needs and for other corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 1.75%, 2.75% and 2.75%, respectively at March 31, 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 of $4.7 million are being amortized over the term of the facility and the amortization expense is included in Interest expense on the accompanying Condensed Consolidated Statements of Income as follows (in thousands):

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Amortization Expense | $473 | $— |

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 March 31, 2011.

| | Actual | Covenant Requirement |
|---|---|---|
| Consolidated Net Worth | $1,113 | $873 |
| Recourse leverage ratio | 57.8 % | 65.0 % |

Enserco Credit Facility

In May 2010, Enserco entered into an agreement for a two-year $250.0 million committed credit facility. The facility contains an accordion feature which allows Enserco, with the consent of the administrative agent, to increase commitments under the facility to $350.0 million. Maximum borrowings under the facility are subject to a sub-limit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. Margins for base rate borrowings are 1.75% and for Eurodollar borrowings are 2.50%. The facility covenants include tangible net worth, net working capital and realized net working capital requirements. Enserco was in compliance with the covenants of this facility as of March 31, 2011.

At March 31, 2011, $147.1 million of letters of credit were issued and outstanding under this facility and there were no cash borrowings outstanding.

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

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Amortization expense | $268 | $533 |

Corporate Term Loan

In December 2010, we entered into a one-year $100.0 million term loan (the "Loan") with J.P. Morgan and Union Bank due in December 2011. The cost of borrowing under the Loan was based on a spread of 137.5 basis points over LIBOR (1.69% at March 31, 2011). The covenants are substantially the same as those which are included in the Revolving Credit Facility. We were in compliance with these covenants as of March 31, 2011.

(7) EARNINGS PER SHARE

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

| Period Ended March 31, 2011 | Three Months | |
|---|---|---|
| | Income | Average Shares |
| Net income | $ 26,910 | 39,059 |
| Dilutive effect of: | | |
| Restricted stock | — | 132 |
| Options | — | 17 |
| Forward Equity Issuance | — | 460 |
| Other | — | 93 |
| Diluted earnings | $ 26,910 | 39,761 |
| | | |
| Diluted earnings per share | $ 0.68 | |

13

| Period Ended March 31, 2010 | Three Months | |
|---|---|---|
| | Income | Average Shares |
| Net income | $31,434 | 38,848 |
| Dilutive effect of: | | |
| Restricted stock | — | 89 |
| Options | — | — |
| Other | — | 72 |
| Diluted earnings | $31,434 | 39,009 |
| | | |
| Diluted earnings per share | $0.81 | |

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 March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Options to purchase common stock | 83 | 264 |
| Restricted stock | 7 | — |
| | 90 | 264 |

(8) COMPREHENSIVE INCOME (LOSS)

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

| | Three Months Ended March 31, 2011 | |
|---|---|---|
| Net income | | $26,910 |
| Other comprehensive income (loss), net of tax: | | |
| Fair value adjustment on derivatives designated as cash flow hedges | $(3,785) | |
| Taxes | 1,637 | |
| Fair value adjustment on derivatives designated as cash flow hedges, net of tax | | (2,148) |
| | | |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss) | $861 | |
| Taxes | (292) | |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax | | 569 |
| | | |
| Comprehensive income | | $25,331 |

| | Three Months Ended March 31, 2010 | |
|---|---|---|
| Net income | | $31,434 |
| Other comprehensive income (loss), net of tax: | | |
| Minimum pension liability adjustments | $19 | |
| Taxes | (7) | |
| Minimum pension liability adjustments, net of tax | | 12 |
| Fair value adjustment on derivatives designated as cash flow hedges | $2,007 | |
| Taxes | (591) | |
| Fair value adjustment on derivatives designated as cash flow hedges, net of tax | | 1,416 |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss) | $2,938 | |
| Taxes | (1,061) | |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax | | 1,877 |
| Comprehensive income | | $34,739 |

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

| | March 31, 2011 | December 31, 2010 | March 31, 2010 |
|---|---|---|---|
| Derivatives designated as cash flow hedges | $(14,016) | $(12,437) | $(6,182) |
| Employee benefit plans | (11,142) | (11,142) | (9,624) |
| Amount from equity-method investees | (2) | (2) | (53) |
| Total | $(25,160) | $(23,581) | $(15,859) |

(9) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock during the first three months of 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. Actual shares are not issued until the end of the performance plan period (December 31, 2013). Performance shares are awarded based on our total stockholder return over the designated performance period as measured against a selected peer group and can range from 0% to 175% of target. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria. The performance awards are paid 50% in the form of cash and 50% in shares of common stock. The grant date fair value was $25.91 per share.

- We issued 14,111 shares of common stock under the 2010 short-term incentive compensation plan during the three months ended March 31, 2011. Pre-tax compensation cost related to the awards was approximately $0.4 million, which was accrued for in 2010.

- We granted 125,963 restricted common shares during the three months ended March 31, 2011. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $3.8 million will be recognized over the three-year vesting period.

- 2,500 stock options were exercised during the three months ended March 31, 2011 at a weighted-average exercise price of $30.81 per share which provided $0.1 million of proceeds.

Total compensation expense recognized for all equity compensation plans for the three months ended March 31, 2011 and 2010 was $2.4 million and $1.8 million, respectively.

As of March 31, 2011, total unrecognized compensation expense related to non-vested stock awards was $11.0 million and is expected to be recognized over a weighted-average period of 2.2 years.

Dividend Reinvestment and Stock Purchase Plan

We have a Dividend Reinvestment and Stock Purchase Plan ("DRIP") under which stockholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We issued 25,026 new shares at a weighted-average price of $31.07 during the three months ended March 31, 2011. At March 31, 2011, 164,667 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% of aggregate consolidated net income, if positive, since January 1, 2005. As of March 31, 2011, we were in compliance with the above covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed as of March 31, 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 March 31, 2011, the restricted net assets at our Utilities Group were approximately $193.7 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 March 31, 2011 were $86.2 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.

16

Forward Equity Issuance

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 $33.44 on March 31, 2011, and the forward price on the date for the initial equity forward of $27.95 and over-allotment shares of $27.95, the fair value net cash settlement of the 4,000,000 equity forward instrument and 413,519 over-allotment shares was approximately $24.2 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.

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 March 31, 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 $123.4 million. Assuming required notices were given and actions taken, the forward instruments could have also been net settled at March 31, 2011 with delivery of cash of approximately $23.5 million or approximately 706,000 shares of common stock to J.P. Morgan.

(10) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

We have three non-contributory defined benefit pension plans (the "Pension Plans"). One Pension Plan covers certain eligible employees of the following subsidiaries: Black Hills Service Company, Black Hills Power, WRDC and BHEP; one Pension Plan covers certain eligible employees of our subsidiary, 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 components of net periodic benefit cost for the three Plans were as follows (in thousands):

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Service cost | $1,355 | $1,533 |
| Interest cost | 3,732 | 3,773 |
| Expected return on plan assets | (4,239) | (3,623) |
| Prior service cost | 25 | 305 |
| Net loss | 1,135 | 500 |
| Net periodic benefit cost | $2,008 | $2,488 |

Non-pension Defined Benefit Postretirement Healthcare Plans

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



---

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

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Service cost | $375 | $377 |
| Interest cost | 542 | 611 |
| Expected return on plan assets | (41) | (52) |
| Prior service cost (benefit) | (120) | (77) |
| Net loss (gain) | 169 | 159 |
| Net periodic benefit cost | $925 | $1,018 |

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

Supplemental Non-qualified Defined Benefit Plans

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

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

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Service cost | $257 | $171 |
| Interest cost | 324 | 321 |
| Prior service cost | 1 | 1 |
| Net loss | 127 | 71 |
| Net periodic benefit cost | $709 | $564 |

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 March 31, 2011 | Anticipated Contributions Remaining for 2011 | Anticipated Contributions for 2012 |
|---|---|---|---|
| Defined Benefit Pension Plans | $— | $550 | $13,431 |
| Non-Pension Defined Benefit Postretirement Healthcare Plans | $882 | $2,647 | $3,765 |
| Supplemental Non-Qualified Defined Benefit Plans | $235 | $707 | $896 |

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

Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of March 31, 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 supply 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 supply 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 interest in the partnership 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 Balance Sheets was as follows (in thousands):

| Three Months Ended March 31, 2011 | External Operating Revenues | Intercompany Operating Revenues | Net Income (Loss) |
|---|---|---|---|
| Utilities: | | | |
| Electric | $144,430 | $3,839 | $10,249 |
| Gas | 230,266 | — | 19,263 |
| Non-regulated Energy: | | | |
| Oil and Gas | 17,906 | — | (715) |
| Power Generation | 687 | 6,933 | 1,186 |
| Coal Mining | 7,614 | 7,881 | (1,298) |
| Energy Marketing | 2,397 | 68 | (2,641) |
| Corporate [(a)] | — | — | 934 |
| Intercompany eliminations | — | (18,721) | (68) |
| Total | $403,300 | $— | $26,910 |

| Three Months Ended March 31, 2010 | External Operating Revenues | Intercompany Operating Revenues [b] | Net Income (Loss) |
|---|---|---|---|
| Utilities: | | | |
| Electric | $144,387 | $4,422 | $9,852 |
| Gas [c] | 243,170 | — | 19,498 |
| Non-regulated Energy: | | | |
| Oil and Gas | 19,743 | — | 2,348 |
| Power Generation | 1,334 | 6,734 | 1,080 |
| Coal Mining | 6,882 | 7,098 | 1,346 |
| Energy Marketing | 9,856 | (84) | 2,193 |
| Corporate [a] | — | — | (4,967) |
| Intercompany eliminations | — | (17,042) | 84 |
| Total | $425,372 | $1,128 | $31,434 |

(a) Net income (loss) includes a $3.6 million net after-tax mark-to-market gain on interest rate swaps for the three months ended March 31, 2011 and a $2.0 million net after-tax mark-to-market loss on these same interest rate swaps for the three months ended March 31, 2010.
(b) Total Revenues have been restated to reflect elimination of intercompany activities previously not eliminated. See Note 1 for further discussion.
(c) Net income (loss) includes a $1.7 million after-tax gain on the sale of operating assets as a result of annexation proceedings by the City of Omaha, Nebraska.

| Total assets | March 31, 2011 | December 31, 2010 | March 31, 2010 |
|---|---|---|---|
| Utilities: | | | |
| Electric | $1,868,600 | $1,834,019 | $1,701,329 |
| Gas | 683,927 | 722,287 | 644,734 |
| Non-regulated Energy: | | | |
| Oil and Gas | 355,357 | 349,991 | 348,156 |
| Power Generation | 336,827 | 293,334 | 185,856 |
| Coal Mining | 94,416 | 96,962 | 82,776 |
| Energy Marketing | 293,544 | 314,930 | 324,478 |
| Corporate | 94,357 | 99,986 | 71,310 |
| Total | $3,727,028 | $3,711,509 | $3,358,639 |

## (12) RISK MANAGEMENT ACTIVITIES

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

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

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

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

- Foreign currency exchange risk associated with marketing transactions 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 in this Note along with Note 13.

Trading Activities

Energy Marketing

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

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

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

We use a number of quantitative tools to measure, monitor and limit our exposure to market risk in our marketing portfolio. We limit and monitor our market risk through established limits on the nominal size of positions based on type of trade, location and duration. Such limits include those on fixed price, basis, index, storage, transportation and foreign exchange positions.

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

The contract or notional amounts and terms of our marketing activities and derivative commodity instruments were as follows:

| | Outstanding at March 31, 2011 | | Outstanding at December 31, 2010 | | Outstanding at March 31, 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 | 649,523 | 19 | 399,128 | 22 | 240,400 | 19 |
| Natural gas basis swaps sold | 671,468 | 19 | 426,903 | 22 | 245,790 | 19 |
| Natural gas fixed-for-float swaps purchased | 199,897 | 30 | 135,005 | 33 | 87,161 | 20 |
| Natural gas fixed-for-float swaps sold | 196,305 | 19 | 150,803 | 22 | 99,233 | 22 |
| Natural gas physical purchases | 147,699 | 33 | 144,948 | 36 | 125,570 | 24 |
| Natural gas physical sales | 134,202 | 33 | 143,021 | 36 | 123,620 | 24 |
| Natural gas futures purchased | 13,570 | 13 | — | — | — | — |
| Natural gas futures sold | 12,050 | 2 | — | — | — | — |

| | Outstanding at March 31, 2011 | | Outstanding at December 31, 2010 | | Outstanding at March 31, 2010 | |
|---|---|---|---|---|---|---|
| | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) |
| (in thousands of Bbls) | | | | | | |
| Crude oil physical purchases | 6,779 | 13 | 5,628 | 16 | 5,296 | 9 |
| Crude oil physical sales | 6,783 | 13 | 6,921 | 16 | 5,647 | 9 |
| Crude oil swaps purchased | 65 | 4 | 20 | 3 | — | — |
| Crude oil swaps sold | 275 | 4 | 240 | 4 | 94 | 2 |

| | Outstanding at March 31, 2011 | | Outstanding at December 31, 2010 | |
|---|---|---|---|---|
| | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) |
| (in thousands of tons) | | | | |
| Coal fixed-for-float swaps purchased | 5,330 | 33 | 4,060 | 36 |
| Coal fixed-for-float swaps sold | 6,140 | 33 | 3,720 | 36 |
| Coal physical purchases | 25,575 | 45 | 24,634 | 48 |
| Coal physical sales | 11,065 | 33 | 9,046 | 36 |
| Coal options purchased | 2,970 | 45 | 2,835 | 48 |
| Coal options sold | 552 | 9 | 270 | 12 |

| | Outstanding at March 31, 2011 | | Outstanding at December 31, 2010 | |
|---|---|---|---|---|
| | Notional Amounts | Latest expiration (months) | Notional Amounts | Latest expiration (months) |
| (in thousands of MWh): | | | | |
| Power fixed-for-float swaps purchased | 3,009 | 33 | 902 | 11 |
| Power fixed-for-float swaps sold | 3,008 | 33 | 902 | 11 |

21

Derivatives and certain other marketing activities were marked to fair value and the related gains and/or losses recognized in earnings. The amounts included in the accompanying Condensed Consolidated Balance Sheets and Condensed Statements of Income were as follows (in thousands):

| | March 31, 2011 | December 31, 2010 | March 31, 2010 |
|---|---|---|---|
| Derivative assets, current | $41,482 | $43,862 | $40,541 |
| Derivative assets, non-current | $3,951 | $6,635 | $2,409 |
| Derivative liabilities, current | $31,167 | $14,550 | $17,733 |
| Derivative liabilities, non-current | $(236) | $3,464 | $(588) |
| Cash collateral receivable (payable) included in derivative assets/liabilities | $2,984 | $3,958 | $171 |
| Unrealized gain | $11,518 | $28,525 | $25,634 |

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in fair value hedge transactions. These volumes include market adjustments based on published industry quotations. Market adjustments are recorded in Materials, supplies and fuel on the accompanying Condensed Consolidated Balance Sheets and the related unrealized gain/loss on the Condensed Consolidated Statements of Income, effectively offsetting the earnings impact of the unrealized gain/loss recognized on the associated derivative asset or liability described above. As of March 31, 2011, December 31, 2010 and March 31, 2010, the market adjustments recorded in Materials, supplies and fuel were $0.3 million, $(9.1) million and $(11.0) 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 is reported in earnings.

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

| | March 31, 2011 | | December 31, 2010 | | March 31, 2010 | |
|---|---|---|---|---|---|---|
| | Crude Oil Swaps/ Options | Natural Gas Swaps | Crude Oil Swaps/ Options | Natural Gas Swaps | Crude Oil Swaps/ Options | Natural Gas Swaps |
| Notional* | 487,500 | 5,974,800 | 424,500 | 6,821,800 | 565,500 | 10,142,050 |
| Maximum terms in years ** | 1 | 0.25 | 0.25 | 0.25 | 0.25 | 0.75 |
| Derivative assets, current | $108 | $6,649 | $248 | $7,675 | $2,816 | $9,151 |
| Derivative assets, non-current | $— | $975 | $19 | $2,606 | $220 | $3,248 |
| Derivative liabilities, current | $4,688 | $— | $3,814 | $— | $2,655 | $53 |
| Derivative liabilities, non-current | $2,678 | $157 | $1,301 | $— | $1,428 | $— |
| Pre-tax accumulated other comprehensive income (loss) included in balance sheets | $(7,613) | $7,467 | $(5,313) | $10,281 | $(1,908) | $12,346 |
| Earnings | $355 | $— | $465 | $— | $861 | $— |

* Crude oil in Bbls, gas in MMBtu.

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

Based on March 31, 2011 market prices, a $1.6 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 purchases and distributes natural gas in four states. During the winter heating season, our gas customers are exposed to the effect of volatile natural gas prices; therefore, as allowed or required by state utility commissions, we have entered into certain exchange traded natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives in accordance with accounting standards for derivatives and mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. Gains and losses, as well as option premiums upon settlement, on these transactions are recorded as Regulatory assets or Regulatory liabilities in accordance with accounting standards for regulated operations. Accordingly, the earnings impact is recognized in the Consolidated Income Statements as a component of PGA costs when the related costs are recovered through our rates as part of PGA costs in operating revenue.

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

| | Outstanding at March 31, 2011 | | Outstanding at December 31, 2010 | | Outstanding at March 31, 2010 | |
|---|---|---|---|---|---|---|
| | Notional Amounts (MMBtus) | Latest Expiration (months) | Notional Amounts (MMBtus) | Latest Expiration (months) | Notional Amounts (MMBtus) | Latest Expiration (months) |
| Natural gas futures purchased | 4,680,000 | 24 | 6,670,000 | 15 | 4,740,000 | 24 |
| Natural gas options purchased | — | — | 1,730,000 | 3 | — | — |

We had the following derivative balances related to the hedges in our Gas Utilities (in thousands):

| | March 31, 2011 | December 31, 2010 | March 31, 2010 |
|---|---|---|---|
| Derivative assets, current | $1,056 | $4,787 | $1,943 |
| Derivative assets, non-current | $209 | $— | $— |
| Derivative liabilities, non-current | $— | $1,620 | $324 |
| Net unrealized gain (loss) included in regulatory assets | $(2,455) | $(8,030) | $(6,475) |
| Cash collateral receivable (payable) included in derivative assets/liabilities | $3,720 | $10,355 | $8,094 |
| Option premium included in Derivative assets, current | $— | $842 | $— |

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):

| | March 31, 2011 | | December 31, 2010 | | March 31, 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 | 5.75 | 0.75 | 6.00 | 1.00 | 6.75 | 0.75 |
| Derivative liabilities, current | $6,769 | $48,515 | $6,823 | $53,980 | $6,571 | $41,822 |
| Derivative liabilities, non-current | $12,955 | $— | $14,976 | $— | $10,917 | $— |
| Pre-tax accumulated other comprehensive gain (loss) included in Condensed Consolidated Balance Sheets | $(19,724) | $— | $(21,799) | $— | $(17,488) | $— |
| Pre-tax (loss) gain included in Condensed Consolidated Income Statements | $— | $5,465 | $— | $(15,193) | $— | $(3,035) |

* Maximum terms in years reflect the amended mandatory early termination dates of the seven and 17 year de-designated swaps. If the mandatory early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date.

Based on March 31, 2011 market interest rates and balances related to our $150.0 million in designated interest rate swaps, a loss of approximately $6.8 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 $250 million notional swaps that are not designated as hedges for accounting purposes.

Foreign Exchange Contracts

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

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

| | As of March 31, 2011 | | As of December 31, 2010 | | As of March 31, 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 | $— | — |
| Canadian dollars sold | $8,000 | 1 | $— | — | $— | — |

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

| | As of March 31, 2011 | As of December 31, 2010 | As of March 31, 2010 |
|---|---|---|---|
| Fair Value | $(106) | $(143) | $— |

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

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Unrealized foreign exchange gain (loss) | $(252) | $132 |
| Realized foreign exchange gain (loss) | $338 | $(141) |

(13) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

Financial assets and liabilities carried at fair value are classified and disclosed in one of the following three categories:

Level 1 — Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities or listed derivatives.

Level 2 — Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Recurring Fair Value Measures

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis (in thousands):

| | As of March 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Counterparty Netting and Cash Collateral[(a)] | Total |
| Assets: | | | | | |
| Commodity derivatives — Energy Marketing | $— | $181,201 | $9,702 | $(145,470) | $45,433 |
| Commodity derivatives — Oil and Gas | — | 7,626 | 106 | — | 7,732 |
| Commodity derivatives — Utilities Group | — | (2,455) | — | 3,720 | 1,265 |
| Money market funds | 9,050 | — | — | — | 9,050 |
| Total | $9,050 | $186,372 | $9,808 | $(141,750) | $63,480 |
| | | | | | |
| Liabilities: | | | | | |
| Commodity derivatives — Energy Marketing | $— | $173,886 | $5,396 | $(148,457) | $30,825 |
| Commodity derivatives — Oil and Gas | — | 7,523 | — | — | 7,523 |
| Foreign currency derivative | — | 106 | — | — | 106 |
| Interest rate swaps | — | 68,239 | — | — | 68,239 |
| Total | $— | $249,754 | $5,396 | $(148,457) | $106,693 |

| | As of December 31, 2010 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Counterparty Netting and Cash Collateral[(a)] | 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 — Utilities Group | — | (5,568) | — | 10,355 | 4,787 |
| Money market funds | 8,050 | — | — | — | 8,050 |
| Foreign currency derivative | — | 166 | — | — | 166 |
| Total | $8,050 | $171,284 | $8,242 | $(113,694) | $73,882 |
| | | | | | |
| Liabilities: | | | | | |
| Commodity derivatives — Energy Marketing | $— | $143,537 | $2,463 | $(128,007) | $17,993 |
| Commodity derivatives — Oil and Gas | — | 5,115 | — | — | 5,115 |
| Commodity derivatives — Utilities Group | — | 1,620 | — | — | 1,620 |
| Foreign currency derivative | — | 21 | — | — | 21 |
| Interest rate swaps | — | 75,779 | — | — | 75,779 |

| | | | | | |
|---|---|---|---|---|---|
| Total | $— | $226,072 | $2,463 | $(128,007 ) | $100,528 |

| | As of March 31, 2010 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Counterparty Netting and Cash Collateral[a] | Total |
| Assets: | | | | | |
| Commodity derivatives — Energy Marketing | $— | $214,788 | $1,183 | $(172,968 ) | $43,003 |
| Commodity derivatives — Oil and Gas | — | 14,127 | 1,255 | — | 15,382 |
| Commodity derivatives — Utilities Group | — | (5,829 ) | — | 8,094 | 2,265 |
| Money market funds | 9,000 | — | — | — | 9,000 |
| Total | $9,000 | $223,086 | $2,438 | $(164,874 ) | $69,650 |
| | | | | | |
| Liabilities: | | | | | |
| Commodity derivatives — Energy Marketing | $— | $189,194 | $1,143 | $(173,139 ) | $17,198 |
| Commodity derivatives — Oil and Gas | — | 4,082 | — | — | 4,082 |
| Commodity derivatives — Utilities Group | — | 324 | — | — | 324 |
| Interest rate swaps | — | 59,311 | — | — | 59,311 |
| Total | $— | $252,911 | $1,143 | $(173,139 ) | $80,915 |

(a) Cash Collateral on deposit in margin accounts under master netting agreements at March 31, 2011, December 31, 2010 and March 31, 2010 totaled a net $6.7 million, $14.3 million and $8.3 million, respectively.

The following tables present the changes in level 3 recurring fair value for the three months ended March 31, 2011 and 2010, respectively (in thousands):

| | Three Months Ended March 31, 2011 Commodity Derivatives |
|---|---|
| Balance as of beginning of period | $5,779 |
| Unrealized losses | (6,199 ) |
| Unrealized gains | 6,201 |
| Purchases | — |
| Issuances | — |
| Settlements | (2,219 ) |
| Transfers into level 3 [a] | 820 |
| Transfers out of level 3[b] | 31 |
| Balances at end of period | $4,413 |
| | |
| Changes in unrealized gains (losses) relating to instruments still held as of quarter-end | $(1,027 ) |

| | Three Months Ended March 31, 2010 Commodity Derivatives | |
|---|---|---|
| Balance as of beginning of period | $(556 | ) |
| Unrealized losses | (1,215 | ) |
| Unrealized gains | 1,381 | |
| Purchases, issuance and settlements | (307 | ) |
| Transfers into level 3 [(a)] | — | |
| Transfers out of level 3[(b)] | 1,992 | |
| Balances at end of period | $1,295 | |
| | | |
| Changes in unrealized gains (losses) relating to instruments still held as of quarter-end | $1,745 | |

____________

(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 less than $(0.1) million and $0.3 million for the three months ended March 31, 2011 and 2010, respectively, are included in Operating revenues on the accompanying Condensed Consolidated Statements of Income while less than $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 months ended March 31, 2011 and 2010, respectively. Commodity derivatives classified as level 3, may be economically hedged as part of a total portfolio of instruments that may be classified in level 1 or 2, or with instruments that may not be accounted for at fair value. Accordingly, gains and losses associated with level 3 balances may not necessarily reflect trends occurring in the underlying business. Further, unrealized gains and losses for the period from level 3 items may be offset by unrealized gains and losses in positions classified in level 1 or 2, as well as positions that have been realized during the quarter.

Fair Value Measures

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis and do not reflect the netting of asset and liability positions. Further, the amounts do not include net cash collateral of $6.7 million, $14.3 million and $8.3 million on deposit in margin accounts at March 31, 2011, December 31, 2010, and March 31, 2010, respectively, to collateralize certain financial instruments, which is included in Derivative assets - current, Derivative assets - non-current and/or Derivative liabilities - current. Therefore, the gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Condensed Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 12.

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

As of March 31, 2011

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|---|---|---|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $39 | $131 |
| Commodity derivatives | Derivative assets — non-current | — | — |
| Commodity derivatives | Derivative liabilities — current | 97 | 289 |
| Commodity derivatives | Derivative liabilities — non-current | — | — |
| Interest rate swaps | Derivative liabilities — current | — | 6,769 |
| Interest rate swaps | Derivative liabilities — non-current | — | 12,955 |
| Total derivatives designated as hedges | | $136 | $20,144 |
| | | | |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $58,930 | $10,346 |
| Commodity derivatives | Derivative assets — non-current | 26,674 | 21,539 |
| Commodity derivatives | Derivative liabilities — current | 156,557 | 198,015 |
| Commodity derivatives | Derivative liabilities — non-current | 1,453 | 4,052 |
| Foreign currency derivatives | Derivative liabilities — current | — | 106 |
| Interest rate swap | Derivative liabilities — current | — | 48,515 |
| Total derivatives not designated as hedges | | $243,614 | $282,573 |

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 |
| 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 | 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 March 31, 2010

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|---|---|---|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $12,551 | $732 |
| Commodity derivatives | Derivative assets — non-current | 19 | — |
| Commodity derivatives | Derivative liabilities — current | — | 193 |
| Commodity derivatives | Derivative liabilities — non-current | — | 20 |
| Interest rate swaps | Derivative liabilities — current | — | 6,571 |
| Interest rate swaps | Derivative liabilities — non-current | — | 10,918 |
| Total derivatives designated as hedges | | $12,570 | $18,434 |
| | | | |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $196,378 | $161,518 |
| Commodity derivatives | Derivative assets — non-current | 19,881 | 14,023 |
| Commodity derivatives | Derivative liabilities — current | 8,884 | 29,234 |
| Commodity derivatives | Derivative liabilities — non-current | 519 | 1,731 |
| Interest rate swaps | Derivative liabilities — current | — | 41,822 |
| Total derivatives not designated as hedges | | $225,662 | $248,328 |

Our derivative activities are discussed in Note 12. The following tables present the impact that derivatives had on our Condensed Consolidated Statements of Income:

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 March 31, 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 | |
| Commodity derivatives | Operating revenue | $(9,717 | ) |
| Fair value adjustment for natural gas inventory designated as the hedged item | Operating revenue | 9,382 | |
| | | $(335 | ) |

| | | Three Months Ended March 31, 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 | |
| Commodity derivatives | Operating revenue | $11,208 | |
| Fair value adjustment for natural gas inventory designated as the hedged item | Operating revenue | (10,747 | ) |
| | | $461 | |

28

Cash Flow Hedges

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

Three Months Ended March 31, 2011

| Derivatives in Cash Flow Hedging Relationships | Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion) | Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) | Amount of 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 | $298 | Interest expense | $(1,892) | | $— |
| Commodity derivatives | (4,083) | Operating revenue | 1,031 | Operating revenue | — |
| Total | $(3,785) | | $(861) | | $— |

Three Months Ended March 31, 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 | $(2,074) | Interest expense | $(305) | | $— |
| Commodity derivatives | 6,581 | Operating revenue | 3,243 | Operating revenue | (163) |
| Total | $4,507 | | $2,938 | | $(163) |

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

| Derivatives Not Designated as Hedging Instruments | Location of Gain/(Loss) on Derivatives Recognized in Income | Three Months Ended March 31, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income |
|---|---|---|
| Commodity derivatives | Operating revenue | $(4,230) |
| Interest rate swaps - unrealized | Interest rate swaps — unrealized (loss) gain | 5,465 |
| Interest rate swaps - realized | Interest expense | (3,352) |
| Foreign currency contracts | Operating revenue | (249) |
| | | $(2,366) |

Derivatives Not Designated as Hedging Instruments

Three Months Ended

| Derivatives Not Designated as Hedging Instruments | Location of Gain/(Loss) on Derivatives Recognized in Income | March 31, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income |
|---|---|---|
| Commodity derivatives | Operating revenue | $(2,659) |
| Interest rate swaps - unrealized | Interest rate swaps — unrealized (loss) gain | (3,035) |
| Interest rate swaps - realized | Interest expense | (3,317) |
| Foreign currency contracts | Operating revenue | — |
| | | $(9,011) |

(14) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair value of our financial instruments at March 31, 2011, December 31, 2010 and March 31, 2010 was as follows (in thousands):

| | March 31, 2011 | | December 31, 2010 | | March 31, 2010 | |
|---|---|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash, cash equivalents | $44,016 | $44,016 | $32,438 | $32,438 | $136,023 | $136,023 |
| Restricted cash | $3,406 | $3,406 | $4,260 | $4,260 | $27,215 | $27,215 |
| Derivative financial instruments - assets | $54,430 | $54,430 | $65,832 | $65,832 | $60,650 | $60,650 |
| Derivative financial instruments - liabilities | $106,693 | $106,693 | $100,528 | $100,528 | $80,915 | $80,915 |
| Notes payable | $287,000 | $287,000 | $249,000 | $249,000 | $223,000 | $223,000 |
| Long-term debt, including current maturities | $1,189,084 | $1,260,539 | $1,191,231 | $1,290,519 | $1,017,940 | $1,102,574 |

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 as required by Black Hills Wyoming project financing agreements.

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 three 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 March 31, 2011, cannot be reasonably determined and could have a material adverse effect on our results of operations or financial position.

Guarantees

As of December 31, 2010, the Company 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.

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<br>Gas Utilities |
| Non-regulated Energy | Oil and Gas<br>Power Generation<br>Coal Mining<br>Energy Marketing |

Our Utilities Group consists of our Electric and Gas Utility 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 reported within the Electric Utilities segment, also 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 energy 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 revenues from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as 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 months ended March 31, 2011 and 2010, and our financial condition as of March 31, 2011, December 31, 2010, and March 31, 2010.
are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 58.

Results of Operations

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.

Executive Summary, Significant Events and Overview

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net income for the three months ended March 31, 2011 was $26.9 million, or $0.68 per share, compared to Net income of $31.4 million, or $0.81 per share, reported for the same period in 2010. The 2011 Net income includes a $3.6 million non-cash after-tax unrealized mark-to-market gain on certain interest rate swaps. The 2010 Net income included a $2.0 million non-cash after-tax unrealized mark-to-market loss on these same interest rate swaps and a $1.7 million after-tax gain on sale of operating assets at Nebraska Gas.

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Operating Revenues * | | |
| Utilities | $378,535 | $391,979 |
| Non-regulated Energy | 43,486 | 51,563 |
| Intercompany eliminations | (18,721) | (17,042) |
| | $403,300 | $426,500 |
| | | |
| Net income (loss) | | |
| Utilities | $29,512 | $29,350 |
| Non-regulated Energy | (3,536) | 7,051 |
| Corporate | 934 | (4,967) |
| | $26,910 | $31,434 |

* 2010 Operating Revenues have been restated to eliminate inter-company revenues previously not eliminated. This change did not have an impact on our gross margin or net income.

Net income decreased $4.5 million for the three months ended March 31, 2011 reflecting the following:

Utilities

- A $0.4 million increase in Electric Utilities earnings;
- A $0.2 million decrease in the Gas Utilities earnings;

Non-regulated Energy

- A $3.1 million decrease in Oil and Gas earnings;
- A $2.6 million decrease in Coal Mining earnings;
- A $5.0 million decrease in Energy Marketing earnings;
- Power Generation earnings comparable to first quarter of 2010; and

Corporate

- A $5.9 million decrease in unallocated Corporate expenses.

Business Group highlights are as follows:

Utilities Group

- New and interim rates were implemented in five utility jurisdictions during 2010. Consequently, revenues have been positively impacted for rates that were not in effect in the prior period.

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

- Effective February 10, 2011 the IUB approved a settlement agreement for an increase in annual utility revenue of $3.4 million at Iowa Gas. Interim rates equal to a $2.6 million increase went into effect in June 2010;
- Construction of gas-fired generation to serve Colorado Electric customers is moving forward to start providing energy by the end of 2011. The 180 MW generation project is expected to cost approximately $227 million, of which $212.9 million has been expended through March 31, 2011;
- On April 28, 2011, Colorado Electric filed a request with the CPUC for a revenue increase of $40.2 million to recover costs 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;

- On April 28, 2011, Black Hills Power filed a request for declaratory ruling from the SDPUC asking to confirm that a proposed 20 MW wind farm site near Belle Fourche, SD is reasonable and cost effective. This $38.0 million project would be owned by Black Hills Power and advance our progress toward the State of South Dakota's objective that 10% of all electricity sold be obtained from renewable, recycled and conserved energy resources by 2015;

- 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 $27.0 million and is expected to begin serving Colorado Electric customers no later than December 31, 2012;

- On March 14, 2011, Colorado Electric filed a request for a CPCN to construct a third utility-owned 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; and

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

Non-regulated Energy Group

- Construction of gas-fired generation at Colorado IPP to serve a 20-year PPA with Colorado Electric is moving forward to start providing energy by the end of 2011. The 200 MW project is expected to cost approximately $260 million, of which $203.1 million has been expended through March 31, 2011.

Corporate

- We recognized a non-cash unrealized mark-to-market gain related to certain interest rate swaps of $5.5 million for the first three months of 2011 compared to a $3.0 million non-cash unrealized mark-to-market loss on these swaps for the same period in 2010.

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

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 and 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 March 31, | |
|---|---|---|
| | 2011 | 2010 |
| | (in thousands) | |
| Revenue — electric | $134,870 | $132,768 |
| Revenue — gas | 13,399 | 16,041 |
| Total revenue | 148,269 | 148,809 |
| | | |
| Fuel and purchased power — electric | 65,678 | 73,511 |
| Purchased gas | 8,396 | 11,191 |
| Total fuel, purchased power and purchased gas | 74,074 | 84,702 |
| | | |
| Gross margin — electric | 69,192 | 59,257 |
| Gross margin — gas | 5,003 | 4,850 |
| Total gross margin | 74,195 | 64,107 |
| | | |
| Operations and maintenance | 37,114 | 32,768 |
| Depreciation and amortization | 12,824 | 11,189 |
| Total operating expenses | 49,938 | 43,957 |
| | | |
| Operating income | 24,257 | 20,150 |
| | | |
| Interest expense, net | (9,944) | (8,254) |
| Other income | 409 | 2,125 |
| Income tax expense | (4,473) | (4,169) |
| | | |
| Net income | $10,249 | $9,852 |

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

| | Three Months Ended March 31, | |
|---|---|---|
| Revenue - electric (in thousands) | 2011 | 2010 |
| Residential: | | |
| Black Hills Power | $17,170 | $14,479 |
| Cheyenne Light | 8,071 | 7,925 |
| Colorado Electric | 20,436 | 19,416 |
| Total Residential | 45,677 | 41,820 |
| | | |
| Commercial: | | |
| Black Hills Power | 17,314 | 14,539 |
| Cheyenne Light | 12,543 | 12,456 |
| Colorado Electric | 16,585 | 15,690 |
| Total Commercial | 46,442 | 42,685 |
| | | |
| Industrial: | | |
| Black Hills Power | 5,764 | 4,637 |
| Cheyenne Light | 2,612 | 2,530 |
| Colorado Electric | 7,867 | 6,944 |
| Total Industrial | 16,243 | 14,111 |
| | | |
| Municipal: | | |
| Black Hills Power | 734 | 653 |
| Cheyenne Light | 391 | 231 |
| Colorado Electric | 2,936 | 1,687 |
| Total Municipal | 4,061 | 2,571 |
| | | |
| Contract Wholesale: | | |
| Black Hills Power | 4,620 | 6,718 |
| | | |
| Off-system Wholesale: | | |
| Black Hills Power | 6,953 | 8,716 |
| Cheyenne Light | 2,887 | 2,591 |
| Colorado Electric [(a)] | — | 7,333 |
| Total Off-system Wholesale | 9,840 | 18,640 |
| | | |
| Other: | | |
| Black Hills Power | 6,639 | 4,747 |
| Cheyenne Light | 689 | 912 |
| Colorado Electric | 659 | 564 |
| Total Other | 7,987 | 6,223 |
| | | |
| Total Revenue - electric | $134,870 | $132,768 |

(a) Colorado Electric has an agreement with the CPUC which requires the deferral of off-system margins until a sharing mechanism is settled upon; due to the agreement Colorado Electric deferred $2.9 million in off-system revenue during the first quarter of 2011.

35

| | Three Months Ended March 31, | |
|---|---|---|
| Quantities Generated and Purchased (in MWh) | 2011 | 2010 |
| Generated — | | |
| Coal-fired: | | |
| Black Hills Power | 437,838 | 430,573 |
| Cheyenne Light | 171,371 | 176,424 |
| Colorado Electric | 56,675 | 70,251 |
| Total Coal-fired | 665,884 | 677,248 |
| | | |
| Gas and Oil-fired: | | |
| Black Hills Power | 1,024 | 2,838 |
| Cheyenne Light | — | — |
| Colorado Electric | — | — |
| Total Gas and Oil-fired | 1,024 | 2,838 |
| | | |
| Total Generated: | | |
| Black Hills Power | 438,862 | 433,411 |
| Cheyenne Light | 171,371 | 176,424 |
| Colorado Electric | 56,675 | 70,251 |
| Total Generated | 666,908 | 680,086 |
| | | |
| Purchased — | | |
| Black Hills Power | 375,612 | 429,682 |
| Cheyenne Light | 197,169 | 192,857 |
| Colorado Electric | 482,785 | 541,202 |
| Total Purchased | 1,055,566 | 1,163,741 |
| | | |
| Total Generated and Purchased: | | |
| Black Hills Power | 814,474 | 863,093 |
| Cheyenne Light | 368,540 | 369,281 |
| Colorado Electric | 539,460 | 611,453 |
| Total Generated and Purchased | 1,722,474 | 1,843,827 |

| Quantity Sold (in MWh) | Three Months Ended March 31, 2011 | 2010 |
|---|---|---|
| Residential: | | |
| Black Hills Power | 174,400 | 174,535 |
| Cheyenne Light | 72,878 | 74,820 |
| Colorado Electric | 157,355 | 167,029 |
| Total Residential | 404,633 | 416,384 |
| | | |
| Commercial: | | |
| Black Hills Power | 178,237 | 184,438 |
| Cheyenne Light | 145,599 | 145,209 |
| Colorado Electric | 165,734 | 170,954 |
| Total Commercial | 489,570 | 500,601 |
| | | |
| Industrial: | | |
| Black Hills Power | 88,749 | 86,663 |
| Cheyenne Light | 40,828 | 40,759 |
| Colorado Electric | 83,909 | 84,510 |
| Total Industrial | 213,486 | 211,932 |
| | | |
| Municipal: | | |
| Black Hills Power | 8,302 | 8,226 |
| Cheyenne Light | 2,444 | 934 |
| Colorado Electric | 27,747 | 15,778 |
| Total Municipal | 38,493 | 24,938 |
| | | |
| Contract Wholesale: | | |
| Black Hills Power [(a)] | 89,959 | 168,465 |
| | | |
| Off-system Wholesale: | | |
| Black Hills Power | 242,156 | 231,047 |
| Cheyenne Light | 84,185 | 84,267 |
| Colorado Electric [(b)] | 78,503 | 159,775 |
| Total Off-system Wholesale | 404,844 | 475,089 |
| | | |
| Total Quantity Sold: | | |
| Black Hills Power | 781,803 | 853,374 |
| Cheyenne Light | 345,934 | 345,989 |
| Colorado Electric | 513,248 | 598,046 |
| Total Quantity Sold | 1,640,985 | 1,797,409 |
| | | |
| Losses and Company Use: | | |
| Black Hills Power | 32,671 | 9,719 |
| Cheyenne Light | 22,606 | 23,292 |
| Colorado Electric | 26,212 | 13,407 |
| Total Losses and Company Use | 81,489 | 46,418 |
| | | |
| Total Energy | 1,722,474 | 1,843,827 |

(a) Decrease in 2011 MWh due to the termination of wholesale contracts with two previous wholesale power customers who acquired ownership interest in the Wygen III facility
(b) Includes 75,803 MWh at Colorado Electric for which $0.3 million gross margin was deferred in accordance with an agreement with the CPUC

| Degree Days | Three Months Ended March 31, 2011 | | 2010 | |
|---|---|---|---|---|
| Heating Degree Days: | Actual | Variance from Normal | Actual | Variance from Normal |
| Black Hills Power | 3,707 | 12 % | 3,392 | 3 % |
| Cheyenne Light | 3,123 | — % | 3,110 | (1 )% |
| Colorado Electric | 2,781 | 5 % | 2,777 | 5 % |

| | Electric Utilities Power Plant Availability Three Months Ended March 31, 2011 | 2010 |
|---|---|---|
| Coal-fired plants | 91.3 %(a) | 94.0 %(b) |
| Other plants | 98.6 % | 99.7 % |
| Total availability | 93.9 % | 96.2 % |

____________

(a) Reflects a planned major outage at the PacifiCorp-operated Wyodak plant.
(b) Reflects an unplanned 12 day outage at the PacifiCorp-operated Wyodak plant due to a collapsed scrubber vessel.

Cheyenne Light Natural Gas Distribution

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

| | Three Months Ended March 31, 2011 | 2010 |
|---|---|---|
| Revenue - gas (in thousands): | | |
| Residential | $7,978 | $9,513 |
| Commercial | 3,807 | 4,833 |
| Industrial | 1,276 | 1,458 |
| Other | 338 | 237 |
| Total Revenue - gas | $13,399 | $16,041 |
| | | |
| Gross Margin (in thousands): | | |
| Residential | $3,388 | $3,252 |
| Commercial | 1,212 | 1,217 |
| Industrial | 177 | 167 |
| Other | 226 | 214 |
| Total Gross Margin | $5,003 | $4,850 |
| | | |
| Volumes Sold (Dth): | | |
| Residential | 1,068,461 | 1,139,543 |
| Commercial | 623,723 | 661,118 |
| Industrial | 256,521 | 242,175 |
| Total Volumes Sold | 1,948,705 | 2,042,836 |

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net income was $10.2 million for the three months ended March 31, 2011 compared to $9.9 million for the three months ended March 31, 2010 as a result of:

Gross margin: Gross margin increased $10.1 million primarily due to an increase of $12.0 million resulting from Black Hills Power and Colorado Electric rate cases implemented during 2010 and additional margins of $1.1 million related to recent transmission investments. These increases were partially offset by a decrease in off-system sales margin, lower retail quantities at Colorado Electric, and a decrease in revenue resulting from two previous wholesale power customers acquiring an ownership interest in Wygen III. Colorado Electric has an agreement with the CPUC which requires the deferral of off-system operating income until a sharing mechanism is settled upon. Due to the agreement Colorado Electric deferred $0.3 million in off-system operating income during the quarter.

Operations and maintenance: Operations and maintenance increased $4.3 million primarily due to additional costs associated with Wygen III which began commercial operation on April 1, 2010, an increase in employee compensation and benefit costs and increased corporate allocations.

Depreciation and amortization: Depreciation and amortization increased $1.6 million primarily due to commencement of depreciation on the Wygen III plant.

Interest expense, net: Interest expense, net increased $1.7 million primarily due to higher debt balances related to recent capital projects and higher interest rates.

Other income: Other income decreased $1.7 million primarily due to lower AFUDC-equity due to the placement of Wygen III into commercial operation.

Income tax expense: The effective tax rate for the Electric Utilities for the three months ended March 31, 2011 was comparable to the same period in the prior year.

Gas Utilities

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| | (in thousands) | |
| Sales revenue: | | |
| Natural gas — regulated | $223,032 | $235,455 |
| Other — non-regulated services | 7,234 | 7,715 |
| Total sales revenue | 230,266 | 243,170 |
| | | |
| Cost of sales: | | |
| Natural gas — regulated | 149,503 | 163,427 |
| Other — non-regulated services | 3,626 | 4,018 |
| Total cost of sales | 153,129 | 167,445 |
| | | |
| Gross margin | 77,137 | 75,725 |
| | | |
| Operations and maintenance | 34,560 | 34,358 |
| Gain on sale of operating assets | — | (2,683) |
| Depreciation and amortization | 6,021 | 7,045 |
| Total operating expenses | 40,581 | 38,720 |
| | | |
| Operating income (loss) | 36,556 | 37,005 |
| | | |
| Interest expense, net | (6,972) | (6,185) |
| Other income (expense) | 25 | (211) |
| Income tax benefit (expense) | (10,346) | (11,111) |
| | | |
| Net income (loss) | $19,263 | $19,498 |

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

| | Three Months Ended March 31, | |
|---|---|---|
| Sales Revenue (in thousands) | 2011 | 2010 |
| Residential: | | |
| Colorado | $22,986 | $22,852 |
| Nebraska | 58,399 | 57,094 |
| Iowa | 47,431 | 48,679 |
| Kansas | 27,953 | 33,344 |
| Total Residential | 156,769 | 161,969 |
| | | |
| Commercial: | | |
| Colorado | 4,633 | 4,989 |
| Nebraska | 19,918 | 21,410 |
| Iowa | 20,883 | 22,789 |
| Kansas | 9,296 | 11,250 |
| Total Commercial | 54,730 | 60,438 |
| | | |
| Industrial: | | |
| Colorado | 115 | 44 |
| Nebraska | 173 | 1,505 |
| Iowa | 737 | 911 |
| Kansas | 1,120 | 787 |
| Total Industrial | 2,145 | 3,247 |
| | | |
| Transportation: | | |
| Colorado | 328 | 281 |
| Nebraska | 4,359 | 4,649 |
| Iowa | 1,325 | 1,200 |
| Kansas | 2,067 | 1,938 |
| Total Transportation | 8,079 | 8,068 |
| | | |
| Other: | | |
| Colorado | 31 | 27 |
| Nebraska | 608 | 612 |
| Iowa | 126 | 444 |
| Kansas | 544 | 650 |
| Total Other | 1,309 | 1,733 |
| | | |
| Total Regulated | 223,032 | 235,455 |
| | | |
| Non-regulated Services | 7,234 | 7,715 |
| | | |
| Total Sales Revenue | $230,266 | $243,170 |

| | Three Months Ended March 31, | |
|---|---|---|
| Gross Margin (in thousands) | 2011 | 2010 |
| Residential: | | |
| Colorado | $6,120 | $6,590 |
| Nebraska | 18,917 | 16,336 |
| Iowa | 16,281 | 15,455 |
| Kansas | 10,078 | 10,217 |
| Total Residential | 51,396 | 48,598 |
| | | |
| Commercial: | | |
| Colorado | 1,032 | 1,217 |
| Nebraska | 4,840 | 5,139 |
| Iowa | 4,163 | 4,613 |
| Kansas | 2,536 | 2,580 |
| Total Commercial | 12,571 | 13,549 |
| | | |
| Industrial: | | |
| Colorado | 36 | 23 |
| Nebraska | 50 | 163 |
| Iowa | 90 | 85 |
| Kansas | 231 | 183 |
| Total Industrial | 407 | 454 |
| | | |
| Transportation: | | |
| Colorado | 328 | 281 |
| Nebraska | 4,359 | 4,649 |
| Iowa | 1,325 | 1,200 |
| Kansas | 2,067 | 1,951 |
| Total Transportation | 8,079 | 8,081 |
| | | |
| Other: | | |
| Colorado | 31 | 27 |
| Nebraska | 608 | 612 |
| Iowa | 126 | 444 |
| Kansas | 311 | 263 |
| Total Other | 1,076 | 1,346 |
| | | |
| Total Regulated | 73,529 | 72,028 |
| | | |
| Non-regulated Services | 3,608 | 3,697 |
| | | |
| Total Gross Margin | $77,137 | $75,725 |

| | Three Months Ended March 31, | |
|---|---|---|
| Volumes Sold (in Dth) | 2011 | 2010 |
| Residential: | | |
| Colorado | 2,720,005 | 2,820,847 |
| Nebraska | 6,070,237 | 6,336,387 |
| Iowa | 5,313,290 | 5,393,894 |
| Kansas | 3,430,879 | 3,568,617 |
| Total Residential | 17,534,411 | 18,119,745 |
| | | |
| Commercial: | | |
| Colorado | 581,696 | 655,373 |
| Nebraska | 2,343,110 | 2,545,124 |
| Iowa | 2,845,746 | 2,908,104 |
| Kansas | 1,302,931 | 1,345,148 |
| Total Commercial | 7,073,483 | 7,453,749 |
| | | |
| Industrial: | | |
| Colorado | 15,614 | 3,754 |
| Nebraska | 13,248 | 219,970 |
| Iowa | 109,801 | 131,266 |
| Kansas | 196,328 | 110,624 |
| Total Industrial | 334,991 | 465,614 |
| | | |
| Transportation: | | |
| Colorado | 345,171 | 298,543 |
| Nebraska | 5,948,046 | 7,990,628 |
| Iowa | 5,553,065 | 5,312,748 |
| Kansas | 4,440,270 | 4,209,828 |
| Total Transportation | 16,286,552 | 17,811,747 |
| | | |
| Other: | | |
| Colorado | — | — |
| Nebraska | — | 976 |
| Iowa | — | 42,297 |
| Kansas | 44,985 | 59,009 |
| Total Other | 44,985 | 102,282 |
| | | |
| Total Volumes Sold | 41,274,422 | 43,953,137 |

| Degree Days | Three Months Ended March 31, 2011 | |
|---|---|---|
| Heating Degree Days: | Actual | Variance From Normal |
| Colorado | 2,761 | (4)% |
| Nebraska | 3,281 | 2% |
| Iowa | 3,694 | —% |
| Kansas* | 2,625 | 2% |
| Combined Gas Utilities Heating Degree Days | 3,212 | 1% |

| Degree Days | Three Months Ended March 31, 2010 | |
|---|---|---|
| Heating Degree Days: | Actual | Variance From Normal |
| Colorado | 2,837 | —% |
| Nebraska | 3,372 | 6% |
| Iowa | 3,525 | (4)% |
| Kansas* | 2,691 | 6% |
| Combined Gas Utilities Heating Degree Days | 3,203 | 2% |

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

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

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net income was $19.3 million in the three months ended March 31, 2011 compared to Net income of $19.5 million for the three months ended March 31, 2010 as a result of:

Gross margin: Gross margin increased $1.4 million primarily due to approved rate cases, partially offset by 4% lower volumes.

Operations and maintenance: Operations and maintenance was comparable to the same period in the prior year.

Depreciation and amortization: Depreciation and amortization decreased $1.0 million primarily due to assets that became fully depreciated during 2010.

Interest expense, net: Interest expense, net increased $0.8 million primarily due to higher interest rates, partially offset by increased intercompany interest income.

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

Income tax benefit (expense): The effective tax rate for the three months ended March 31, 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):

| | Type of Service | Date Requested | Date Effective | Amount Requested | Amount Approved | Return on Equity | Approved Capital Structure Equity | Approved Capital Structure Debt |
|---|---|---|---|---|---|---|---|---|
| Nebraska Gas (1) | Gas | 12/2009 | 3/2010 | $12.1 | $8.3 | 10.1 % | 52.0 % | 48.0 % |
| Iowa Gas (2) | Gas | 6/2010 | 2/2011 | $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 % |
| Colorado Electric (4) | Electric | 1/2010 | 8/2010 | $22.9 | $17.9 | 10.5 % | 52.0 % | 48.0 % |
| Colorado Electric (5) | 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. On August 18, 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 Public Advocate has filed several appeals which the NPSC has denied. The Public Advocate has filed a notice of appeal with the Court of Appeals.

(2) On June 8, 2010, Iowa Gas filed a request with the IUB for a $4.7 million, or 2.9%, revenue increase to recover the cost of capital investments 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 on February 10, 2011.

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

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

Included in the rate case order was a provision that off-system operating income be shared with customers commencing August 6, 2010. The percentage of operating income 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. Colorado Electric filed a proposal for a sharing mechanism with the CPUC on April 27, 2011. Since August 2010, $1.0 million in off-system operating income has been deferred.

(5) 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 associated with the 180 MW generating facility 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.

Non-regulated Energy Group

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

Oil and Gas

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Revenue | $17,906 | $19,743 |
| Operations and maintenance | 10,567 | 9,734 |
| Depreciation, depletion and amortization | 7,321 | 6,111 |
| Total operating expenses | 17,888 | 15,845 |
| Operating income (loss) | 18 | 3,898 |
| Interest expense, net | (1,383) | (782) |
| Other income (expense) | (185) | 303 |
| Income tax (expense) benefit | 835 | (1,071) |
| Net income (loss) | $(715) | $2,348 |

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

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Fuel production: | | |
| Bbls of oil sold | 103,550 | 84,391 |
| Mcfe of natural gas sold | 2,134,658 | 2,152,176 |
| Mcf equivalent sales | 2,755,958 | 2,658,522 |

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Average price received: (a) | | |
| Gas/Mcf (b) | $4.65 | $5.91 |
| Oil/Bbl | $66.83 | $74.39 |
| Depletion expense/Mcfe | $2.36 | $2.00 |

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

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

| | Three Months Ended March 31, 2011 | | | |
|---|---|---|---|---|
| | LOE | Gathering, Compression and Processing | Production Taxes | Total |
| San Juan | $1.25 | $0.46 | $0.55 | $2.26 |
| Piceance | 0.68 | 0.80 | 0.25 | 1.73 |
| Powder River [(a)] | 1.31 | — | 1.29 | 2.60 |
| Williston [(a)] | 0.26 | — | 1.50 | 1.76 |
| All other properties | 1.66 | — | 0.40 | 2.06 |
| Total average | $1.18 | $0.28 | $0.74 | $2.20 |

(a) Powder River and Williston are primarily oil producing properties with relatively higher operating expenses on a per Mcfe basis.

| | Three Months Ended March 31, 2010 | | | |
|---|---|---|---|---|
| | LOE | Gathering, Compression and Processing | Production Taxes | Total |
| San Juan | $1.40 | $0.37 | $0.72 | $2.49 |
| Piceance | 0.53 | 0.81 | 0.38 | 1.72 |
| Powder River [(a)] | 1.37 | — | 1.13 | 2.50 |
| Williston [(a)] | 0.89 | — | 1.00 | 1.89 |
| All other properties | 1.22 | — | 0.13 | 1.35 |
| Total average | $1.25 | $0.25 | $0.67 | $2.17 |

(a) Powder River and Williston are primarily oil producing properties with relatively higher operating expenses on a per Mcfe basis.

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net loss was $0.7 million for the three months ended March 31, 2011 compared to Net income of $2.3 million for the same period in 2010 as a result of:

Revenue: Revenue decreased $1.8 million primarily due to a 21% decrease in the average hedged price of natural gas and a 10% decrease in the average hedged price of crude oil, partially offset by a 23% increase in crude oil volumes primarily from new wells in our ongoing Bakken drilling program in North Dakota. The decrease in crude oil price was influenced by fixed price swaps previously entered into at prices significantly below current crude oil market prices. These swaps represent approximately 58% of our crude oil volume for the current quarter. Gas volumes, exclusive of gas liquids, decreased 1%.

Operations and maintenance: Operations and maintenance costs increased $0.8 million primarily due to increased compensation costs and ad valorem taxes.

Depreciation, depletion and amortization: Depreciation, depletion and amortization increased $1.2 million primarily due to a higher depletion rate and increased production. The increase in the depletion rate reflects the addition of higher cost crude oil reserves, primarily attributable to our Bakken drilling activities.

Interest expense, net: Interest expense, net increased $0.6 million primarily due to higher interest rates.

Other income (expense): Other income (expense) decreased $0.5 million primarily due to lower earnings from equity investments.

Income tax (expense) benefit: Income tax (expense) benefit for the first quarter of 2011 was impacted primarily by a $0.3 million credit for research and development projects.

Coal Mining

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| | (in thousands) | |
| Revenue | $15,495 | $13,980 |
| | | |
| Operations and maintenance | 14,572 | 10,241 |
| Depreciation, depletion and amortization | 4,618 | 2,890 |
| Total operating expenses | 19,190 | 13,131 |
| | | |
| Operating income (loss) | (3,695) | 849 |
| | | |
| Interest income, net | 960 | 318 |
| Other income | 569 | 556 |
| Income tax benefit (expense) | 868 | (377) |
| | | |
| Net income (loss) | $(1,298) | $1,346 |

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

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Tons of coal sold | 1,370 | 1,392 |
| Cubic yards of overburden moved | 3,455 | 3,571 |

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net loss was $1.3 million for the three months ended March 31, 2011 compared to Net income of $1.3 million in the same period in 2010, as a result of:

Revenue: Revenue increased $1.5 million primarily due to a 10% increase in average price received per ton. The higher average sales price reflects the impact of price escalators in certain of our coal sales contracts. Approximately 35% of our coal production is sold under contracts where the sales price escalates based on actual mining cost increases. In addition, approximately 60% of our 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 a 2% decrease in tons sold. Sales volumes decreased in 2011 as new quantities sold to the Wygen III plant beginning in April 2010 were more than offset by the negative impact from plant outages and the suspension of operations at the Osage power plant.

Operations and maintenance: Operations and maintenance costs increased $4.3 million. Cost increases are reflective of 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, approximately 60% of our production is sold under contracts which 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 included 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: Depreciation, depletion and amortization expense increased $1.7 million related to reclamation costs and increased depreciation on equipment.

Interest income, net: Interest income, net increased $0.6 million primarily due to increased lending to affiliates at higher interest rates.

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

Income tax benefit (expense): The tax benefit for the period ending March 31, 2011 was favorably impacted by research and development credits recorded. Tax expense recorded for the period ended March 31, 2010 was favorably impacted by the benefit generated by percentage depletion.

Energy Marketing

| | Three Months Ended March 31, 2011 | 2010 |
|---|---|---|
| | (in thousands) | |
| Gross margin — | | |
| Realized gross margin | $5,257 | $12,053 |
| Unrealized gross margin | (2,792) | (2,281) |
| Total gross margin | 2,465 | 9,772 |
| | | |
| Operating expenses | 5,757 | 5,426 |
| Depreciation and amortization | 139 | 132 |
| Total operating expenses | 5,896 | 5,558 |
| | | |
| Operating income (loss) | (3,431) | 4,214 |
| | | |
| Interest expense, net | (452) | (762) |
| Other income (expense) | (1) | (31) |
| Income tax (expense) benefit | 1,243 | (1,228) |
| | | |
| Net income (loss) | $(2,641) | $2,193 |

Gross margins by commodity:
Three Months Ended March 31,

| | Gas | Oil | Coal[(a)] | Power[(b)] | Environmental[(b)] |
|---|---|---|---|---|---|
| 2011 | | | | | |
| Realized | $5,288 | $258 | $1,076 | $(1,365) | $— |
| Unrealized | (3,477) | (1,981) | 1,649 | 1,017 | — |
| Total | $1,811 | $(1,723) | $2,725 | $(348) | $— |
| | | | | | |
| 2010 | | | | | |
| Realized | $10,521 | $1,532 | $— | $— | $— |
| Unrealized | (1,004) | (1,277) | — | — | — |
| Total | $9,517 | $255 | $— | $— | $— |

(a) Coal marketing activity began June 1, 2010, the acquisition date of the coal marketing portfolio.
(b) Power and environmental marketing commenced operations late in third quarter of 2010.

Following is a summary of average daily quantities marketed:

| | Three Months Ended March 31, 2011 | 2010 |
|---|---|---|
| Natural gas physical sales — MMBtus | 1,730,183 | 1,753,200 |
| Crude oil physical sales — Bbls | 21,243 | 13,430 |
| Coal physical sales — Tons | 36,532 | — |

Gas, 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 March 31, 2011 | As of December 31, 2010 | As of March 31, 2010 |
|---|---|---|---|
| Natural gas (MMBtus) | 1,567,070 | 14,922,353 | 10,328,896 |
| Crude oil (Bbls) | 143,647 | 198,052 | 74,140 |
| Coal (Tons) | 40,095 | 1,529 | — |

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net loss was $2.6 million for the three months ended March 31, 2011 compared to Net income of $2.2 million in the same period in 2010 as a result of:

Gross margin: Gross margin decreased $7.3 million primarily driven by lower gross margin from both natural gas and crude oil marketing compared to the 2010 period. Power marketing activities, which began during the third quarter of 2010, produced a slight gross margin loss for the three months ended March 31, 2011. These decreases to gross margin were partially offset by approximately $2.7 million in gross margin provided by the coal marketing operations that began in the second quarter of 2010.

Operating expenses: Operating expenses increased $0.3 million primarily due to higher compensation expense related to staff marketing new commodities in new geographic regions, and an increase in fees primarily related to usage of letters of credit.

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

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

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

Income tax (expense) benefit: The effective income tax rate for the three months ended March 31, 2011 was comparable to the same period in the prior year.

Power Generation

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| | (in thousands) | |
| Revenue | $7,620 | $8,068 |
| | | |
| Operations and maintenance | 4,188 | 3,374 |
| Depreciation and amortization | | |