

BLACK HILLS CORP /SD/
Form 10-Q
August 06, 2014

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

Form 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES
EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2014

OR

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
625 Ninth Street
Rapid City, South Dakota 57701

IRS Identification Number 46-0458824

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 No

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 No

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 Accelerated filer
Non-accelerated filer Smaller reporting company

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes No

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

| Class | Outstanding at July 31, 2014 | shares |
|--------------------------------|------------------------------|--------|
| Common stock, \$1.00 par value | 44,641,421 | |

TABLE OF CONTENTS

| | Page |
|---|------------------|
| Glossary of Terms and Abbreviations | <u>3</u> |
| PART I. FINANCIAL INFORMATION | <u>5</u> |
| Item 1. Financial Statements | <u>5</u> |
| Condensed Consolidated Statements of Income (Loss) - unaudited Three and Six Months Ended June 30, 2014 and 2013 | <u>5</u> |
| Condensed Consolidated Statements of Comprehensive Income (Loss) - unaudited Three and Six Months Ended June 30, 2014 and 2013 | <u>6</u> |
| Condensed Consolidated Balance Sheets - unaudited June 30, 2014, December 31, 2013 and June 30, 2013 | <u>7</u> |
| Condensed Consolidated Statements of Cash Flows - unaudited Six Months Ended June 30, 2014 and 2013 | <u>9</u> |
| Notes to Condensed Consolidated Financial Statements - unaudited | <u>10</u> |
| Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations | <u>30</u> |
| Item 3. Quantitative and Qualitative Disclosures about Market Risk | <u>60</u> |
| Item 4. Controls and Procedures | <u>61</u> |
| PART II. OTHER INFORMATION | <u>62</u> |
| Item 1. Legal Proceedings | <u>62</u> |
| Item 1A. Risk Factors | <u>62</u> |
| Item 2. Unregistered Sales of Equity Securities and Use of Proceeds | <u>63</u> |
| Item 4. Mine Safety Disclosures | <u>63</u> |
| Item 5. Other Information | <u>63</u> |
| Item 6. Exhibits | <u>63</u> |
| Signatures | <u>65</u> |
| Index to Exhibits | <u>66</u> |

GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations 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) |
| ASU | Accounting Standards Update issued by the FASB |
| Bbl | Barrel |
| BHC | Black Hills Corporation; the Company |
| Black Hills Electric Generation | Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings |
| Black Hills Energy | The name used to conduct the business of Black Hills Utility Holdings, Inc., and its subsidiaries |
| Black Hills Non-regulated Holdings | Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation |
| Black Hills Power | Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation |
| Black Hills Utility Holdings | Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation |
| Black Hills Wyoming | Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation |
| Btu | British thermal unit |
| Cheyenne Light | Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation |
| Cheyenne Prairie | Cheyenne Prairie Generating Station currently being constructed in Cheyenne, Wyoming by Cheyenne Light and Black Hills Power. Construction is expected to be completed for this 132 megawatt facility in 2014. |
| 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 IPP | Black Hills Colorado IPP, LLC a direct wholly-owned subsidiary of Black Hills Electric Generation |
| Cooling degree day | A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average. |
| Conflict Minerals | As defined by Dodd-Frank, conflict minerals are cassiterite, columbite-tantalite, gold and wolframite that are mined in the Democratic Republic of the Congo or surrounding countries |
| CPCN | Certificate of Public Convenience and Necessity |
| CPUC | Colorado Public Utilities Commission |
| CT | Combustion turbine |
| CVA | Credit Valuation Adjustment |
| De-designated interest rate swaps | The \$250 million notional amount interest rate swaps that were originally designated as cash flow hedges under accounting for derivatives and hedges but subsequently de-designated in December 2008. These swaps were settled in November 2013. |
| Dth | |

| | |
|-------|--|
| EPA | Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu) |
| FASB | United States Environmental Protection Agency |
| FERC | Financial Accounting Standards Board |
| Fitch | United States Federal Energy Regulatory Commission |
| GAAP | Fitch Ratings |
| GCA | Accounting principles generally accepted in the United States of America |
| | Gas Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of gas and certain services through to customers. |

| | |
|---------------------------|---|
| Heating Degree Day | A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average. |
| IPP | Independent power producer |
| IRS | United States 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 |
| KCC | Kansas Corporation Commission |
| kV | Kilovolt |
| LIBOR | London Interbank Offered Rate |
| LOE | Lease Operating Expense |
| Mcf | Thousand cubic feet |
| Mcfe | Thousand cubic feet equivalent. |
| MMBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MW | Megawatts |
| MWh | Megawatt-hours |
| NGL | Natural Gas Liquids (7 Gallons equals 1 Mcfe) |
| NOAA | National Oceanic and Atmospheric Administration |
| NOAA Climate Normals | This dataset is produced once every 10 years. This dataset contains daily and monthly normals of temperature, precipitation, snowfall, heating and cooling degree days, frost/freeze dates, and growing degree days calculated from observations at approximately 9,800 stations operated by NOAA's National Weather Service. |
| NOL | Net Operating Loss |
| OTC | Over-the-counter |
| PPA | Power Purchase Agreement |
| Revolving Credit Facility | Our \$500 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2019. |
| SDPUC | South Dakota Public Utilities Commission |
| SEC | U. S. Securities and Exchange Commission |
| S&P | Standard and Poor's, a division of The McGraw-Hill Companies, Inc. |
| 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 (LOSS)

| (unaudited) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|--|-----------|------------------------------|-----------|
| | 2014 | 2013 | 2014 | 2013 |
| | (in thousands, except per share amounts) | | | |
| Revenue | \$283,237 | \$279,826 | \$743,406 | \$660,497 |
| Operating expenses: | | | | |
| Utilities - | | | | |
| Fuel, purchased power and cost of natural gas sold | 101,331 | 99,172 | 331,799 | 267,345 |
| Operations and maintenance | 66,074 | 64,977 | 137,301 | 130,667 |
| Non-regulated energy operations and maintenance | 21,350 | 20,890 | 43,682 | 42,219 |
| Depreciation, depletion and amortization | 36,712 | 35,152 | 72,795 | 69,933 |
| Taxes - property, production and severance | 11,044 | 10,069 | 21,380 | 20,449 |
| Other operating expenses | 149 | 529 | 274 | 1,001 |
| Total operating expenses | 236,660 | 230,789 | 607,231 | 531,614 |
| Operating income | 46,577 | 49,037 | 136,175 | 128,883 |
| Other income (expense): | | | | |
| Interest charges - | | | | |
| Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps) | (17,886 |)(23,369 |)(35,746 |)(47,041 |
| Allowance for funds used during construction - borrowed | 256 | 411 | 526 | 484 |
| Capitalized interest | 246 | 272 | 503 | 538 |
| Unrealized gain (loss) on interest rate swaps, net | — | 18,793 | — | 26,249 |
| Interest income | 576 | 475 | 966 | 760 |
| Allowance for funds used during construction - equity | 293 | 42 | 531 | 242 |
| Other income (expense), net | 409 | 473 | 1,000 | 879 |
| Total other income (expense), net | (16,106 |)(2,903 |)(32,220 |)(17,889 |
| Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes | 30,471 | 46,134 | 103,955 | 110,994 |
| Equity in earnings (loss) of unconsolidated subsidiaries | — | — | — | (86 |
| Income tax benefit (expense) | (10,651 |)(15,616 |)(36,017 |)(37,193 |
| Net income (loss) available for common stock | \$19,820 | \$30,518 | \$67,938 | \$73,715 |
| Earnings (loss) per share of common stock: | | | | |
| Earnings (loss) per share, Basic - | | | | |
| Total income (loss) per share, Basic | \$0.45 | \$0.69 | \$1.53 | \$1.67 |
| Earnings (loss) per share, Diluted - | | | | |
| Total income (loss) per share, Diluted | \$0.44 | \$0.69 | \$1.52 | \$1.66 |
| Weighted average common shares outstanding: | | | | |
| Basic | 44,399 | 44,172 | 44,365 | 44,113 |

Edgar Filing: BLACK HILLS CORP /SD/ - Form 10-Q

| | | | | |
|--|--------|--------|--------|--------|
| Diluted | 44,588 | 44,412 | 44,571 | 44,363 |
| Dividends paid per share of common stock | \$0.39 | \$0.38 | \$0.78 | \$0.76 |

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

5

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

| (unaudited) | Three Months Ended June 30, 2014 | | Six Months Ended June 30, 2014 | |
|---|--|----------|--------------------------------------|----------|
| | 2013 | 2013 | 2013 | 2013 |
| | (in thousands) | | | |
| Net income (loss) available for common stock | \$19,820 | \$30,518 | \$67,938 | \$73,715 |
| Other comprehensive income (loss), net of tax: | | | | |
| Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of \$1,115 and \$(2,174) for the three months ended 2014 and 2013 and \$2,422 and \$(1,057) for the six months ended 2014 and 2013, respectively) | (1,959) |)3,878 | (4,216) |)2,217 |
| Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of \$(774) and \$(647) for the three months ended 2014 and 2013 and \$(1,199) and \$(883) for the six months ended 2014 and 2013, respectively) | 1,403 | 1,201 | 2,183 | 1,669 |
| Benefit plan liability adjustments - net gain (loss) (net of tax of \$0 and \$0 for the three months ended 2014 and 2013 and \$2 and \$0 for the six months ended 2014 and 2013, respectively) | — | — | (2) |)— |
| Benefit plan liability tax adjustments - net gain (loss) | (394) |)— | (394) |)— |
| Benefit plan liability adjustments - prior service cost (net of tax of \$0 and \$0 for the three months ended 2014 and 2013 and \$(90) and \$0 for the six months ended 2014 and 2013, respectively) | — | — | 164 | — |
| Reclassification adjustments of benefit plan liability - prior service cost (net of tax of \$39 and \$(268) for the three months ended 2014 and 2013 and \$43 and \$(251) for the six months ended 2014 and 2013, respectively) | (70) |)364 | (79) |)318 |
| Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax of \$(91) and \$0 for the three months ended 2014 and 2013 and \$(176) and \$(192) for the six months ended 2014 and 2013, respectively) | 168 | — | 325 | 503 |
| Other comprehensive income (loss), net of tax | (852) |)5,443 | (2,019) |)4,707 |
| Comprehensive income (loss) available for common stock | \$18,968 | \$35,961 | \$65,919 | \$78,422 |

See Note 11 for additional disclosures.

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) | As of June 30, 2014 (in thousands) | December 31, 2013 | June 30, 2013 |
|--|---|----------------------|---------------------|
| ASSETS | | | |
| Current assets: | | | |
| Cash and cash equivalents | \$ 14,697 | \$ 7,841 | \$ 30,633 |
| Restricted cash and equivalents | 2 | 2 | 7,279 |
| Accounts receivable, net | 135,145 | 177,573 | 132,726 |
| Materials, supplies and fuel | 81,164 | 88,478 | 73,768 |
| Derivative assets, current | 1,737 | 717 | 903 |
| Income tax receivable, net | 1,043 | 1,460 | 146 |
| Deferred income tax assets, net, current | 23,872 | 18,889 | 38,764 |
| Regulatory assets, current | 64,735 | 24,451 | 26,258 |
| Other current assets | 21,660 | 25,877 | 27,595 |
| Total current assets | 344,055 | 345,288 | 338,072 |
| Investments | 17,096 | 16,697 | 16,566 |
| Property, plant and equipment | 4,408,291 | 4,259,445 | 4,066,502 |
| Less: accumulated depreciation and depletion | (1,325,660) | (1,269,148) | (1,234,578) |
| Total property, plant and equipment, net | 3,082,631 | 2,990,297 | 2,831,924 |
| Other assets: | | | |
| Goodwill | 353,396 | 353,396 | 353,396 |
| Intangible assets, net | 3,286 | 3,397 | 3,508 |
| Regulatory assets, non-current | 138,226 | 138,197 | 180,646 |
| Other assets, non-current | 31,808 | 27,906 | 22,402 |
| Total other assets, non-current | 526,716 | 522,896 | 559,952 |
| TOTAL ASSETS | \$ 3,970,498 | \$ 3,875,178 | \$ 3,746,514 |

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)

| | As of June 30, 2014 | December 31, 2013 | June 30, 2013 |
|---|--------------------------------------|----------------------|---------------------|
| | (in thousands, except share amounts) | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | | |
| Current liabilities: | | | |
| Accounts payable | \$ 100,098 | \$ 130,416 | \$ 88,071 |
| Accrued liabilities | 141,177 | 151,277 | 135,819 |
| Derivative liabilities, current | 3,480 | 3,474 | 69,270 |
| Regulatory liabilities, current | 828 | 10,727 | 20,550 |
| Notes payable | 132,700 | 82,500 | 100,000 |
| Current maturities of long-term debt | 275,000 | — | 255,507 |
| Total current liabilities | 653,283 | 378,394 | 669,217 |
| Long-term debt, net of current maturities | 1,121,950 | 1,396,948 | 958,559 |
| Deferred credits and other liabilities: | | | |
| Deferred income tax liabilities, net, non-current | 476,059 | 432,287 | 387,674 |
| Derivative liabilities, non-current | 4,251 | 5,614 | 12,384 |
| Regulatory liabilities, non-current | 119,462 | 109,429 | 129,013 |
| Benefit plan liabilities | 116,403 | 111,479 | 177,216 |
| Other deferred credits and other liabilities | 137,765 | 133,279 | 129,763 |
| Total deferred credits and other liabilities | 853,940 | 792,088 | 836,050 |
| Commitments and contingencies (See Notes 7, 8, 13, 14 and 15) | | | |
| Stockholders' equity: | | | |
| Common stock equity — | | | |
| Common stock \$1 par value; 100,000,000 shares authorized; issued 44,682,885; 44,550,239; and 44,516,472 shares, respectively | 44,683 | 44,550 | 44,517 |
| Additional paid-in capital | 744,505 | 742,344 | 737,729 |
| Retained earnings | 573,379 | 540,244 | 532,810 |
| Treasury stock, at cost – 40,951; 50,877; and 42,480 shares, respectively | (1,801 |) (1,968 |) (1,587 |
| Accumulated other comprehensive income (loss) | (19,441 |) (17,422 |) (30,781 |
| Total stockholders' equity | 1,341,325 | 1,307,748 | 1,282,688 |
| TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY | \$ 3,970,498 | \$ 3,875,178 | \$ 3,746,514 |

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

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

| | Six Months Ended June 30, | |
|--|---------------------------|-------------|
| | 2014 | 2013 |
| | (in thousands) | |
| Operating activities: | | |
| Net income (loss) available for common stock | \$67,938 | \$73,715 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 72,795 | 69,933 |
| Deferred financing cost amortization | 1,107 | 2,188 |
| Derivative fair value adjustments | (1,660) |)4,248 |
| Stock compensation | 6,908 | 6,896 |
| Unrealized (gain) loss on interest rate swaps, net | — | (26,249) |
| Deferred income taxes | 35,514 | 36,607 |
| Employee benefit plans | 7,409 | 11,096 |
| Other adjustments, net | 1,481 | 8,967 |
| Changes in certain operating assets and liabilities: | | |
| Materials, supplies and fuel | 7,314 | 8,940 |
| Accounts receivable, unbilled revenues and other operating assets | (5,851 |)28,377 |
| Accounts payable and other operating liabilities | (24,978 |)(26,739) |
| Other operating activities, net | 5,858 | (594) |
| Net cash provided by (used in) operating activities | 173,835 | 197,385 |
| Investing activities: | | |
| Property, plant and equipment additions | (177,302 |)(147,230) |
| Other investing activities | (2,994 |)2,006 |
| Net cash provided by (used in) investing activities | (180,296 |)(145,224) |
| Financing activities: | | |
| Dividends paid on common stock | (34,803 |)(33,774) |
| Common stock issued | 1,693 | 2,570 |
| Short-term borrowings - issuances | 214,100 | 133,300 |
| Short-term borrowings - repayments | (163,900 |)(310,300) |
| Long-term debt - issuances | — | 275,000 |
| Long-term debt - repayments | — | (103,786) |
| Other financing activities | (3,773 |)— |
| Net cash provided by (used in) financing activities | 13,317 | (36,990) |
| Net change in cash and cash equivalents | 6,856 | 15,171 |
| Cash and cash equivalents, beginning of period | 7,841 | 15,462 |
| Cash and cash equivalents, end of period | \$14,697 | \$30,633 |

See Note 12 for supplemental disclosure of cash flow information.

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)

(Reference is made to Notes to Consolidated Financial Statements included in the Company's 2013 Annual Report on Form 10-K)

(1) MANAGEMENT'S STATEMENT

The unaudited Condensed Consolidated Financial Statements included herein have been prepared by Black Hills Corporation (together with our subsidiaries the "Company," "us," "we," or "our"), 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 Consolidated Financial Statements should be read in conjunction with the consolidated financial statements and the notes thereto included in our 2013 Annual Report on Form 10-K filed with the SEC.

We conduct our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation, Coal Mining and Oil and Gas. 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. All of our operations and assets are located within the United States.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying Condensed Consolidated Financial Statements reflects all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the June 30, 2014, December 31, 2013, and June 30, 2013 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market price. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2014 and June 30, 2013, and our financial condition as of June 30, 2014, December 31, 2013, and June 30, 2013, 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.

Recently Issued and Adopted Accounting Standards

We have implemented all new accounting pronouncements that are in effect and may impact our financial statements and do not believe that there are any other new accounting pronouncements that have been issued that might have a material impact on our financial position, results of operations, or cash flows.

Revenue from Contracts with Customers, ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The standard provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. ASU 2014-09 is effective for annual and interim reporting periods beginning after December 15, 2016 and early adoption is not

permitted. We are currently assessing the impact, if any, that ASU 2014-09 will have on our financial position, results of operations, or cash flows.

(2) BUSINESS SEGMENT INFORMATION

Segment information and Corporate activities included in the accompanying Condensed Consolidated Statements of Income (Loss) were as follows (in thousands):

| Three Months Ended June 30, 2014 | External Operating Revenue | Inter-company Operating Revenue | Net Income (Loss) |
|-------------------------------------|-----------------------------------|---------------------------------------|-------------------|
| Utilities: | | | |
| Electric | \$ 158,740 | \$ 3,144 | \$ 11,427 |
| Gas | 102,499 | — | 1,994 |
| Non-regulated Energy: | | | |
| Power Generation | 1,267 | 20,713 | 7,194 |
| Coal Mining | 5,583 | 9,068 | 2,016 |
| Oil and Gas | 15,148 | — | (1,660) |
| Corporate activities | — | — | (1,151) |
| Inter-company eliminations | — | (32,925) |) — |
| Total | \$ 283,237 | \$ — | \$ 19,820 |
| Three Months Ended June 30, 2013 | External Operating Revenue | Inter-company Operating Revenue | Net Income (Loss) |
| Utilities: | | | |
| Electric | \$ 154,338 | \$ 3,694 | \$ 10,610 |
| Gas | 105,836 | — | 3,192 |
| Non-regulated Energy: | | | |
| Power Generation | 1,031 | 19,094 | 5,031 |
| Coal Mining | 6,807 | 7,511 | 1,973 |
| Oil and Gas | 11,814 | — | (1,964) |
| Corporate activities ^(a) | — | — | 11,679 |
| Inter-company eliminations | — | (30,299) |) (3) |
| Total | \$ 279,826 | \$ — | \$ 30,518 |
| Six Months Ended June 30, 2014 | External Operating Revenues | Intercompany Operating Revenues | Net Income (Loss) |
| Utilities: | | | |
| Electric | \$ 336,835 | \$ 7,151 | \$ 26,002 |
| Gas | 361,836 | — | 26,692 |
| Non-regulated Energy: | | | |
| Power Generation | 2,536 | 41,792 | 15,267 |
| Coal Mining | 12,201 | 17,948 | 4,480 |
| Oil and Gas | 29,998 | — | (3,682) |
| Corporate activities | — | — | (821) |
| Inter-company eliminations | — | (66,891) |) — |
| Total | \$ 743,406 | \$ — | \$ 67,938 |

| Six Months Ended June 30, 2013 | External Operating Revenues | Intercompany Operating Revenues | Net Income (Loss) |
|-------------------------------------|-----------------------------------|---------------------------------------|-------------------|
| Utilities: | | | |
| Electric | \$312,821 | \$7,841 | \$22,966 |
| Gas | 305,648 | — | 21,675 |
| Non-regulated Energy: | | | |
| Power Generation | 2,053 | 38,432 | 10,675 |
| Coal Mining | 12,817 | 15,084 | 3,038 |
| Oil and Gas | 27,158 | — | (2,017) |
| Corporate activities ^(a) | — | — | 17,378 |
| Inter-company eliminations | — | (61,357) | — |
| Total | \$660,497 | \$— | \$73,715 |

(a) Corporate activities include a \$12 million and a \$17 million after-tax non-cash mark-to-market gain for the three and six months ended June 30, 2013, respectively on certain interest rate swaps.

Segment information and Corporate balances included in the accompanying Condensed Consolidated Balance Sheets were as follows (in thousands):

| Total Assets (net of inter-company eliminations) as of: | June 30, 2014 | December 31, 2013 | June 30, 2013 |
|---|---------------|-------------------|---------------|
| Utilities: | | | |
| Electric ^(a) | \$2,603,900 | \$2,525,947 | \$2,417,952 |
| Gas | 799,365 | 805,617 | 734,337 |
| Non-regulated Energy: | | | |
| Power Generation ^(a) | 85,269 | 95,692 | 108,515 |
| Coal Mining | 73,701 | 78,825 | 82,553 |
| Oil and Gas | 307,837 | 288,366 | 256,855 |
| Corporate activities | 100,426 | 80,731 | 146,302 |
| Total assets | \$3,970,498 | \$3,875,178 | \$3,746,514 |

The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from (a) the Pueblo Airport Generation Station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.

(3) ACCOUNTS RECEIVABLE

Following is a summary of Accounts receivable, net included in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

| | Accounts Receivable, Trade | Unbilled Revenue | Less Allowance for Accounts Doubtful Accounts Receivable, net | |
|--------------------|-------------------------------|---------------------|--|------------|
| June 30, 2014 | | | | |
| Electric Utilities | \$48,333 | \$21,716 | \$(622) |)\$69,427 |
| Gas Utilities | 43,104 | 9,265 | (1,027) |)51,342 |
| Power Generation | 1,388 | — | — | 1,388 |
| Coal Mining | 1,866 | — | — | 1,866 |
| Oil and Gas | 9,123 | — | (13) |)9,110 |
| Corporate | 2,012 | — | — | 2,012 |
| Total | \$105,826 | \$30,981 | \$(1,662) |)\$135,145 |

| | Accounts Receivable, Trade | Unbilled Revenue | Less Allowance for Accounts Doubtful Accounts Receivable, net | |
|--------------------|-------------------------------|---------------------|--|------------|
| December 31, 2013 | | | | |
| Electric Utilities | \$52,437 | \$23,823 | \$(666) |)\$75,594 |
| Gas Utilities | 49,162 | 41,195 | (558) |)89,799 |
| Power Generation | 1,722 | — | — | 1,722 |
| Coal Mining | 1,711 | — | — | 1,711 |
| Oil and Gas | 8,156 | — | (13) |)8,143 |
| Corporate | 604 | — | — | 604 |
| Total | \$113,792 | \$65,018 | \$(1,237) |)\$177,573 |

| | Accounts Receivable, Trade | Unbilled Revenue | Less Allowance for Accounts Doubtful Accounts Receivable, net | |
|--------------------|-------------------------------|---------------------|--|------------|
| June 30, 2013 | | | | |
| Electric Utilities | \$45,250 | \$24,290 | \$(630) |)\$68,910 |
| Gas Utilities | 38,749 | 13,192 | (1,074) |)50,867 |
| Power Generation | 157 | — | — | 157 |
| Coal Mining | 2,503 | — | — | 2,503 |
| Oil and Gas | 8,373 | — | (19) |)8,354 |
| Corporate | 1,935 | — | — | 1,935 |
| Total | \$96,967 | \$37,482 | \$(1,723) |)\$132,726 |

(4) REGULATORY ACCOUNTING

We had the following regulatory assets and liabilities (in thousands):

| | Maximum Amortization (in years) | As of June 30, 2014 | As of December 31, 2013 | As of June 30, 2013 |
|--|---------------------------------------|------------------------|----------------------------|------------------------|
| Regulatory assets | | | | |
| Deferred energy and fuel cost adjustments - current ^{(a)(d)} | 1 | \$29,605 | \$16,775 | \$15,951 |
| Deferred gas cost adjustments and natural gas price derivatives ^{(a)(d)} | 7 | 39,040 | 12,366 | 13,090 |
| AFUDC ^(b) | 45 | 12,468 | 12,315 | 12,456 |
| Employee benefit plans ^(c) | 13 | 65,874 | 67,059 | 115,379 |
| Environmental ^(a) | subject to approval | 1,314 | 1,800 | 1,798 |
| Asset retirement obligations ^(a) | 44 | 3,278 | 3,266 | 3,257 |
| Bond issue cost ^(a) | 24 | 3,347 | 3,419 | 3,489 |
| Renewable energy standard adjustment ^(a) | 5 | 14,501 | 14,186 | 14,694 |
| Flow through accounting ^(c) | 35 | 22,754 | 20,916 | 17,995 |
| Other regulatory assets ^(a) | 15 | 10,780 | 10,546 | 8,795 |
| | | \$202,961 | \$162,648 | \$206,904 |
| Regulatory liabilities | | | | |
| Deferred energy and gas costs ^(a) | 1 | \$6,490 | \$11,708 | \$22,340 |
| Employee benefit plans ^(c) | 13 | 34,356 | 34,431 | 60,214 |
| Cost of removal ^(a) | 44 | 70,841 | 64,970 | 59,461 |
| Other regulatory liabilities ^(c) | 25 | 8,603 | 9,047 | 7,548 |
| | | \$120,290 | \$120,156 | \$149,563 |

(a) Recovery of costs, but we are not allowed a rate of return.

(b) In addition to recovery of costs, we are allowed a rate of return.

(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base, respectively.

(d) Our deferred energy, fuel cost, and gas cost adjustments represent the cost of electricity and gas delivered to our electric and gas utility customers that is either higher or lower than current rates and will be recovered or refunded in future rates. Increases in the current year balances as of June 30, 2014 are primarily due to higher natural gas prices driven by demand and market conditions during our peak winter heating season. Our electric and gas utilities file periodic quarterly, semi-annual, and/or annual filings to recover these costs based on the respective cost mechanisms approved by their applicable state utility commissions.

(5) MATERIALS, SUPPLIES AND FUEL

The following amounts by major classification are included in Materials, supplies and fuel in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

| | June 30, 2014 | December 31, 2013 | June 30, 2013 |
|--|---------------|-------------------|---------------|
| Materials and supplies | \$51,925 | \$50,196 | \$51,334 |
| Fuel - Electric Utilities | 7,679 | 6,213 | 6,817 |
| Natural gas in storage held for distribution | 21,560 | 32,069 | 15,617 |

| | | | |
|------------------------------------|----------|----------|----------|
| Total materials, supplies and fuel | \$81,164 | \$88,478 | \$73,768 |
|------------------------------------|----------|----------|----------|

(6) EARNINGS PER SHARE

A reconciliation of share amounts used to compute Earnings (loss) per share in the accompanying Condensed Consolidated Statements of Income (loss) is as follows (in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|-----------------------------|-----------|---------------------------|-----------|
| | 2014 | 2013 | 2014 | 2013 |
| Net income (loss) available for common stock | \$ 19,820 | \$ 30,518 | \$ 67,938 | \$ 73,715 |
| Weighted average shares - basic | 44,399 | 44,172 | 44,365 | 44,113 |
| Dilutive effect of: | | | | |
| Equity compensation | 189 | 240 | 206 | 250 |
| Weighted average shares - diluted | 44,588 | 44,412 | 44,571 | 44,363 |

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive (in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|----------------------|-----------------------------|------|---------------------------|------|
| | 2014 | 2013 | 2014 | 2013 |
| Equity compensation | 81 | 28 | 63 | 34 |
| Anti-dilutive shares | 81 | 28 | 63 | 34 |

(7) NOTES PAYABLE AND CURRENT MATURITIES OF LONG-TERM DEBT

We had the following short-term debt outstanding in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

| | June 30, 2014 | | December 31, 2013 | | June 30, 2013 | |
|---------------------------|---------------|----------------------------------|-------------------|----------------------------------|---------------|----------------------------------|
| | Balance | Letters of Outstanding Credit | Balance | Letters of Outstanding Credit | Balance | Letters of Outstanding Credit |
| Revolving Credit Facility | \$ 132,700 | \$ 20,272 | \$ 82,500 | \$ 22,100 | \$ 100,000 | \$ 43,157 |

Revolving Credit Facility

On May 29, 2014, we amended our \$500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to \$750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from S&P and Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.125%, 1.125% and 1.125%, respectively, from May 29, 2014 through June 30, 2014; a reduction of 0.25% for each method of borrowing as compared to the previous arrangement. Borrowings under the facility are primarily Eurodollar based. A commitment fee is charged on the unused amount of the Revolving Credit Facility and was 0.175% based on our credit rating, a reduction of 0.025% compared to the prior arrangement.

Current Maturities Of Long-Term Debt

As of June 30, 2014, our Corporate term loan due June 19, 2015, for \$275 million has been re-classified to Current maturities of long-term debt from Long-term debt, net of current maturities.

Debt Covenants

Our Revolving Credit Facility and our Term Loan require compliance with the following financial covenant at the end of each quarter:

| | As of June 30, 2014 | Covenant Requirement |
|-------------------------|---------------------|----------------------|
| Recourse Leverage Ratio | 54% | Less than 65% |

As of June 30, 2014, we were in compliance with this covenant.

(8) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures as discussed in our 2013 Annual Report on Form 10-K.

Market Risk

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 including, but not limited to:

- Commodity price risk associated with our natural long position in crude oil and natural gas reserves and production; and our fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements, and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

As of June 30, 2014, our credit exposure included a \$0.5 million exposure to a non-investment grade energy marketing company. The remainder of our credit exposure was concentrated primarily among retail utility customers, investment grade rated companies, cooperative utilities and federal agencies. Our derivative and hedging activities recorded in the accompanying Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Income (Loss) and Condensed Consolidated Statements of Comprehensive Income (Loss) are detailed below and in Note 9.

Oil and Gas

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.

To mitigate commodity price risk and preserve cash flows, we primarily use OTC swaps, exchange traded futures and related options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on these instruments. These transactions were designated at inception as cash flow hedges, documented under accounting standards 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 were 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 for which we have elected cash flow hedge accounting is reported in AOCI in the accompanying Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Revenue in the accompanying Condensed Consolidated Statements of Income (Loss).

The contract or notional amounts, terms of our commodity derivatives, and the derivative balances for our Oil and Gas segment reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

| | June 30, 2014 | | December 31, 2013 | | June 30, 2013 | |
|--|---|-------------------------------------|---|-------------------------------------|---|-------------------------------------|
| | Crude Oil Futures, Swaps and Options | Natural Gas Futures and Swaps | Crude Oil Futures, Swaps and Options | Natural Gas Futures and Swaps | Crude Oil Futures, Swaps and Options | Natural Gas Futures and Swaps |
| Notional ^(a) | 424,500 | 9,265,000 | 412,500 | 7,082,500 | 520,500 | 10,712,500 |
| Maximum terms in months ^(b) | 1 | 1 | 3 | 1 | 6 | 1 |
| Derivative assets, current | \$— | \$— | \$55 | \$— | \$610 | \$293 |
| Derivative assets, non-current | \$— | \$— | \$— | \$— | \$— | \$— |
| Derivative liabilities, current | \$— | \$— | \$— | \$— | \$130 | \$276 |
| Derivative liabilities, non-current | \$— | \$— | \$— | \$— | \$— | \$— |

(a) Crude oil in Bbls, natural gas in MMBtus.

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

A \$3.4 million loss is included in AOCI at June 30, 2014, and would be realized over the next 12 months if market prices remained equal to June 30, 2014 prices. Future realized gains or losses fluctuate with market prices.

Utilities

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used for Electric Utility generation plants or those plants under PPAs where our Electric Utilities must provide the generation fuel (tolling agreements), expose our utility customers to volatility in natural gas prices. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP. Unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Condensed Consolidated Balance Sheets in accordance with state commission

guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Condensed Consolidated Statements of Income (Loss).

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

| | June 30, 2014 | | December 31, 2013 | | June 30, 2013 | |
|-----------------------------------|-------------------|-----------------------|-------------------|-----------------------|-------------------|-----------------------|
| | Notional (MMBtus) | Maximum Term (months) | Notional (MMBtus) | Maximum Term (months) | Notional (MMBtus) | Maximum Term (months) |
| Natural gas futures purchased | 16,240,000 | 78 | 17,930,000 | 84 | 13,330,000 | 77 |
| Natural gas options purchased | 3,980,000 | 9 | 3,890,000 | 8 | 2,850,000 | 5 |
| Natural gas basis swaps purchased | 13,415,000 | 66 | 14,785,000 | 60 | 10,650,000 | 66 |

We had the following derivative balances related to the hedges in our Utilities reflected in our Condensed Consolidated Balance Sheets as of (in thousands):

| | June 30, 2014 | December 31, 2013 | June 30, 2013 |
|--|---------------|-------------------|---------------|
| Derivative assets, current | \$1,737 | \$662 | \$— |
| Derivative assets, non-current | \$— | \$— | \$— |
| Derivative liabilities, non-current | \$— | \$— | \$— |
| Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities | \$3,561 | \$7,567 | \$8,450 |

Financing Activities

We entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

| | June 30, 2014 | December 31, 2013 | June 30, 2013 | De-designated Interest Rate Swaps ^(c) |
|--------------------------------------|------------------------------------|------------------------------------|------------------------------------|--|
| | Interest Rate Swaps ^(a) | Interest Rate Swaps ^(a) | Interest Rate Swaps ^(b) | Interest Rate Swaps ^(c) |
| Notional | \$75,000 | \$75,000 | \$150,000 | \$250,000 |
| Weighted average fixed interest rate | 4.97 | % 4.97 | % 5.04 | % 5.67 |
| Maximum terms in years | 2.5 | 3.0 | 3.5 | 0.5 |
| Derivative liabilities, current | \$3,480 | \$3,474 | \$6,965 | \$61,899 |
| Derivative liabilities, non-current | \$4,251 | \$5,614 | \$12,384 | \$— |

(a) These swaps are designated to borrowings on our Revolving Credit Facility, and are priced using three-month LIBOR, matching the floating portion of the related debt.

At June 30, 2013, \$75 million of these interest rate swaps were designated to borrowings on our Revolving Credit Facility and \$75 million were designated to borrowings on our project financing debt at Black Hills Wyoming.

(b) These swaps are priced using three-month LIBOR, matching the floating portion of the related debt. The portion of the swaps that were designated to Black Hills Wyoming were settled during the fourth quarter of 2013 upon repayment of the Black Hills Wyoming project financing.

(c) These swaps were settled during the fourth quarter of 2013.

Based on June 30, 2014, market interest rates and balances related to our interest rate swaps, a loss of approximately \$3.5 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months.

Estimated and actual realized gains or losses will change during future periods as market interest rates change.

Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income (Loss) were as follows (in thousands):

Three Months Ended June 30, 2014

| 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 | \$(337) |) Interest expense | \$(926) |) | \$— |
| Commodity derivatives | (2,737) |) Revenue | (1,251) |) | — |
| Total | \$(3,074) |) | \$(2,177) |) | \$— |

Three Months Ended June 30, 2013

| 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 | \$1,067 |) Interest expense | \$(1,820) |) | \$— |
| Commodity derivatives | 4,985 |) Revenue | (28) |) | — |
| Total | \$6,052 |) | \$(1,848) |) | \$— |

Six Months Ended June 30, 2014

| 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 | \$(429) |) Interest expense | \$(1,820) |) | \$— |
| Commodity derivatives | (6,209) |) Revenue | (1,562) |) | — |
| Total | \$(6,638) |) | \$(3,382) |) | \$— |

Six Months Ended June 30, 2013

| 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) |
|--|---|--|--|--|--|
| | | | | | |

Edgar Filing: BLACK HILLS CORP /SD/ - Form 10-Q

| | | | | | |
|-----------------------|---------|------------------|-----------|---|-----|
| Interest rate swaps | \$1,048 | Interest expense | \$(3,616) |) | \$— |
| Commodity derivatives | 2,226 | Revenue | 1,064 | | — |
| Total | \$3,274 | | \$(2,552) |) | \$— |

19

(9) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

The accounting guidance for fair value measurements requires certain disclosures about assets and liabilities measured at fair value. This guidance establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. 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. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments. For additional information see Notes 1, 8 and 10 to the Consolidated Financial Statements included in our 2013 Annual Report on Form 10-K filed with the SEC.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Valuation Methodologies for Derivatives

Oil and Gas Segment:

The commodity option contracts for our Oil and Gas segment are valued using the market approach and can include calls and puts. Fair value was derived using quoted prices from third-party brokers for similar instruments as to quantity and timing. The prices are then validated through third-party sources and therefore support Level 2 disclosure.

The commodity basis swaps for our Oil and Gas segment are valued using the market approach with the instrument's current forward price strip hedged for the same quantity and date and discounted based on the three-month LIBOR. We utilize observable inputs which support a Level 2 disclosure.

Utilities Segments:

The commodity contracts for our Utilities Segments, valued using the market approach, include exchange-traded futures, options and basis swaps (Level 2) and OTC basis swaps (Level 3) for natural gas contracts. For Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For Level 3 assets and liabilities, fair value was derived using average price quotes from the OTC contract broker and an independent third-party market participant because these instruments are not traded on an exchange.

Corporate Activities:

The interest rate swaps are valued using the market approach. We establish fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the

probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting a Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

The following tables set forth by level within the fair value hierarchy our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments. A discussion of fair value of financial instruments is included in Note 10:

| | As of June 30, 2014 | | | Cash Collateral and Counterparty Total Netting | |
|-------------------------------------|---------------------|----------|---------|--|-----------|
| | Level 1 | Level 2 | Level 3 | | |
| | (in thousands) | | | | |
| Assets: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | \$— | \$— | \$— | \$— | \$— |
| Basis Swaps -- Oil | — | — | — | — | — |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 600 | — | (600 |)— |
| Commodity derivatives — Utilities | — | 4,342 | — | (2,605 |) 1,737 |
| Total | \$— | \$4,942 | \$— | \$(3,205 |) \$1,737 |
| Liabilities: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | \$— | \$— | \$— | \$— | \$— |
| Basis Swaps -- Oil | — | 4,020 | — | (4,020 |)— |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 2,030 | — | (2,030 |)— |
| Commodity derivatives — Utilities | — | 5,989 | — | (5,989 |)— |
| Interest rate swaps | — | 7,731 | — | — | 7,731 |
| Total | \$— | \$19,770 | \$— | \$(12,039 |) \$7,731 |

| | As of December 31, 2013 | | | Cash Collateral and Counterparty Total Netting | |
|-------------------------------------|-------------------------|----------|---------|--|------------|
| | Level 1 | Level 2 | Level 3 | | |
| | (in thousands) | | | | |
| Assets: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | \$— | \$— | \$— | \$— | \$— |
| Basis Swaps -- Oil | — | 130 | — | (75) |) 55 |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 815 | — | (815) |)— |
| Commodity derivatives — Utilities | — | 3,030 | — | (2,368) |) 662 |
| Total | \$— | \$3,975 | \$— | \$(3,258) |) \$717 |
| Liabilities: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | \$— | \$— | \$— | \$— | \$— |
| Basis Swaps -- Oil | — | 1,229 | — | (1,229) |)— |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 531 | — | (531) |)— |
| Commodity derivatives — Utilities | — | 9,100 | — | (9,100) |)— |
| Interest rate swaps | — | 9,088 | — | — |) 9,088 |
| Total | \$— | \$19,948 | \$— | \$(10,860) |) \$9,088 |
| As of June 30, 2013 | | | | | |
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty Total Netting | |
| | (in thousands) | | | | |
| Assets: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | \$— | \$45 | \$— | \$(6) |) \$39 |
| Basis Swaps -- Oil | — | 1,109 | — | (538) |) 571 |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 1,882 | — | (1,589) |) 293 |
| Commodity derivatives — Utilities | — | 1,378 | — | (1,378) |)— |
| Total | \$— | \$4,414 | \$— | \$(3,511) |) \$903 |
| Liabilities: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | \$— | \$181 | \$— | \$(98) |) \$83 |
| Basis Swaps -- Oil | — | 350 | — | (303) |) 47 |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 445 | — | (169) |) 276 |
| Commodity derivatives — Utilities | — | 8,581 | — | (8,581) |)— |
| Interest rate swaps | — | 87,208 | — | (5,960) |) 81,248 |
| Total | \$— | \$96,765 | \$— | \$(15,111) |) \$81,654 |

Fair Value Measures by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis reflecting the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements and the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions; however, the amounts do not include net cash collateral on deposit in margin accounts at June 30, 2014, December 31, 2013, and June 30, 2013, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the 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 8.

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

As of June 30, 2014

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|--|--------------------------------------|---------------------------------------|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$262 | \$— |
| Commodity derivatives | Derivative assets — non-current | 338 | — |
| Commodity derivatives | Derivative liabilities — current | — | 3,702 |
| Commodity derivatives | Derivative liabilities — non-current | — | 2,348 |
| Interest rate swaps | Derivative liabilities — current | — | 3,480 |
| Interest rate swaps | Derivative liabilities — non-current | — | 4,251 |
| Total derivatives designated as hedges | | \$600 | \$13,781 |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$1,737 | \$— |
| Commodity derivatives | Derivative assets — non-current | — | — |
| Commodity derivatives | Derivative liabilities — current | — | — |
| Commodity derivatives | Derivative liabilities — non-current | — | 3,384 |
| Total derivatives not designated as hedges | | \$1,737 | \$3,384 |

As of December 31, 2013

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|--|--------------------------------------|---------------------------------------|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$248 | \$— |
| Commodity derivatives | Derivative assets — non-current | 698 | — |
| Commodity derivatives | Derivative liabilities — current | — | 1,541 |
| Commodity derivatives | Derivative liabilities — non-current | — | 219 |
| Interest rate swaps | Derivative liabilities — current | — | 3,474 |
| Interest rate swaps | Derivative liabilities — non-current | — | 5,614 |
| Total derivatives designated as hedges | | \$946 | \$10,848 |
| Derivatives not designated as hedges: | | | |

Edgar Filing: BLACK HILLS CORP /SD/ - Form 10-Q

| | | | |
|--|--------------------------------------|-------|---------|
| Commodity derivatives | Derivative assets — current | \$662 | \$— |
| Commodity derivatives | Derivative assets — non-current | — | — |
| Commodity derivatives | Derivative liabilities — current | — | — |
| Commodity derivatives | Derivative liabilities — non-current | — | 6,732 |
| Total derivatives not designated as hedges | | \$662 | \$6,732 |

23

As of June 30, 2013

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|--|--------------------------------------|---------------------------------------|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$ 1,225 | \$— |
| Commodity derivatives | Derivative assets — non-current | 1,651 | — |
| Commodity derivatives | Derivative liabilities — current | — | 889 |
| Commodity derivatives | Derivative liabilities — non-current | — | 41 |
| Interest rate swaps | Derivative liabilities — current | — | 6,965 |
| Interest rate swaps | Derivative liabilities — non-current | — | 12,384 |
| Total derivatives designated as hedges | | \$2,876 | \$20,279 |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$ 160 | \$— |
| Commodity derivatives | Derivative assets — non-current | — | — |
| Commodity derivatives | Derivative liabilities — current | — | 1,884 |
| Commodity derivatives | Derivative liabilities — non-current | — | 5,365 |
| Interest rate swaps | Derivative liabilities — current | — | 67,859 |
| Interest rate swaps | Derivative liabilities — non-current | — | — |
| Total derivatives not designated as hedges | | \$ 160 | \$75,108 |

(10) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 9, were as follows (in thousands) as of:

| | June 30, 2014 | | December 31, 2013 | | June 30, 2013 | |
|---|-----------------|-------------|-------------------|-------------|-----------------|-------------|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash and cash equivalents ^(a) | \$14,697 | \$14,697 | \$7,841 | \$7,841 | \$30,633 | \$30,633 |
| Restricted cash and equivalents ^(a) | \$2 | \$2 | \$2 | \$2 | \$7,279 | \$7,279 |
| Notes payable ^(a) | \$132,700 | \$132,700 | \$82,500 | \$82,500 | \$100,000 | \$100,000 |
| Long-term debt, including current maturities ^(b) | \$1,396,950 | \$1,578,756 | \$1,396,948 | \$1,491,422 | \$1,214,066 | \$1,323,543 |

^(a) Carrying value approximates fair value due to either the short-term length of maturity or variable interest rates that approximate prevailing market rates, and therefore is classified in Level 1 in the fair value hierarchy.

^(b) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

(11) OTHER COMPREHENSIVE INCOME (LOSS)

The components of the reclassification adjustments, net of tax, included in Other Comprehensive Income (Loss) for the periods were as follows (in thousands):

| | Location on the Condensed Consolidated Statements of Income (Loss) | Amount Reclassified from AOCI | | | |
|--|--|-------------------------------|---------------|------------------|---------------|
| | | Three Months Ended | | Six Months Ended | |
| | | June 30, 2014 | June 30, 2013 | June 30, 2014 | June 30, 2013 |
| Gains (losses) on cash flow hedges: | | | | | |
| Interest rate swaps | Interest expense | \$926 | \$1,820 | \$1,820 | \$3,616 |
| Commodity contracts | Revenue | 1,251 | 28 | 1,562 | (1,064) |
| | | 2,177 | 1,848 | 3,382 | 2,552 |
| Income tax | Income tax benefit (expense) | (774) | (647) | (1,199) | (883) |
| Reclassification adjustments related to cash flow hedges, net of tax | | \$1,403 | \$1,201 | \$2,183 | \$1,669 |
| Amortization of defined benefit plans: | | | | | |
| Prior service cost | Utilities - Operations and maintenance | \$(25) | \$(31) | \$(51) | \$(62) |
| | Non-regulated energy operations and maintenance | (84) | (32) | (71) | (64) |
| Actuarial gain (loss) | | 158 | 421 | 315 | 842 |

| | | | | | |
|---|---|------|-------|-------|---------|
| | Utilities - Operations and maintenance | | | | |
| | Non-regulated energy operations and maintenance | 101 | 274 | 186 | 548 |
| | | 150 | 632 | 379 | 1,264 |
| Income tax | Income tax benefit (expense) | (52 |)(268 |)(133 |)(443) |
| Reclassification adjustments related to defined benefit plans, net of tax | | \$98 | \$364 | \$246 | \$821 |

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

| | Derivatives as Cash Flow Hedges | Designated Employee Benefit Plans | Total | |
|---|------------------------------------|--------------------------------------|-------------|---|
| Balance as of December 31, 2012 | \$(15,713 |) \$(19,775 |) \$(35,488 |) |
| Other comprehensive income (loss), net of tax | (1,193 |) 457 | (736 |) |
| Balance as of March 31, 2013 | (16,906 |) (19,318 |) (36,224 |) |
| Other comprehensive income (loss), net of tax | 5,079 | 364 | 5,443 | |
| Balance as of June 30, 2013 | \$(11,827 |) \$(18,954 |) \$(30,781 |) |
| Balance as of December 31, 2013 | \$(7,133 |) \$(10,289 |) \$(17,422 |) |
| Other comprehensive income (loss), net of tax | (1,478 |) 311 | (1,167 |) |
| Balance as of March 31, 2014 | (8,611 |) (9,978 |) (18,589 |) |
| Other comprehensive income (loss), net of tax | (556 |) (296 |) (852 |) |
| Balance as of June 30, 2014 | \$(9,167 |) \$(10,274 |) \$(19,441 |) |

(12) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

| Six months ended | June 30, 2014 (in thousands) | June 30, 2013 | |
|--|---------------------------------|---------------|---|
| Non-cash investing and financing activities from continuing operations— | | | |
| Property, plant and equipment acquired with accrued liabilities | \$40,611 | \$45,000 | |
| Increase (decrease) in capitalized assets associated with asset retirement obligations | \$(2,785 |) \$— | |
| Cash (paid) refunded during the period for continuing operations— | | | |
| Interest (net of amounts capitalized) | \$(35,009 |) \$(44,191 |) |
| Income taxes, net | \$(396 |) \$(5,406 |) |

(13) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--------------------------------|-----------------------------|----------|---------------------------|----------|
| | 2014 | 2013 | 2014 | 2013 |
| Service cost | \$1,362 | \$1,608 | \$2,724 | \$3,216 |
| Interest cost | 3,963 | 3,825 | 7,926 | 7,650 |
| Expected return on plan assets | (4,516 |) (4,654 |) (9,032 |) (9,308 |
| Prior service cost | 16 | 16 | 32 | 32 |
| Net loss (gain) | 1,201 | 3,062 | 2,403 | 6,124 |
| Net periodic benefit cost | \$2,026 | \$3,857 | \$4,053 | \$7,714 |

Non-pension Defined Benefit Postretirement Healthcare Plans

The components of net periodic benefit cost for the Non-pension Defined Benefit Postretirement Healthcare Plans were as follows (in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--------------------------------|-----------------------------|-------|---------------------------|---------|
| | 2014 | 2013 | 2014 | 2013 |
| Service cost | \$425 | \$419 | \$850 | \$838 |
| Interest cost | 480 | 417 | 959 | 834 |
| Expected return on plan assets | (21 |)(20 |)(42 |)(40 |
| Prior service cost (benefit) | (107 |)(125 |)(214 |)(250 |
| Net loss (gain) | 40 | 121 | 80 | 242 |
| Net periodic benefit cost | \$817 | \$812 | \$1,633 | \$1,624 |

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

The components of net periodic benefit cost for the Supplemental Non-qualified Defined Benefit and Defined Contribution Plans were as follows (in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---------------------------|-----------------------------|-------|---------------------------|---------|
| | 2014 | 2013 | 2014 | 2013 |
| Service cost | \$374 | \$348 | \$749 | \$696 |
| Interest cost | 362 | 332 | 724 | 664 |
| Prior service cost | 1 | 1 | 1 | 2 |
| Net loss (gain) | 124 | 198 | 249 | 396 |
| Net periodic benefit cost | \$861 | \$879 | \$1,723 | \$1,758 |

Contributions

We anticipate that we will make contributions to the benefit plans during 2014 and 2015. Contributions to the Defined Benefit Pension Plans are cash contributions made directly to the Pension Plan Trust accounts. Contributions to the Healthcare and Supplemental Plan are made in the form of benefit payments. Contributions and anticipated contributions are as follows (in thousands):

| | Contributions Made Three Months Ended June 30, 2014 | Contributions Made Six Months Ended June 30, 2014 | Additional Contributions Anticipated for 2014 | Contributions Anticipated for 2015 |
|--|---|--|--|--|
| Defined Benefit Pension Plans | \$— | \$— | \$— | \$2,806 |
| Non-pension Defined Benefit Postretirement Healthcare Plans | \$956 | \$1,912 | \$1,912 | \$3,822 |
| Supplemental Non-qualified Defined Benefit and Defined Contribution Plans | \$373 | \$746 | \$746 | \$1,494 |

(14) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 18 of our Notes to the Consolidated Financial Statements in our 2013 Annual Report on Form 10-K except for those described below.

Bond Purchase Agreements

On June 30, 2014, Black Hills Power and Cheyenne Light entered into agreements to issue \$160 million of first mortgage bonds to finance Cheyenne Prairie. Black Hills Power will issue \$85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light will issue \$75 million of 4.53% coupon first mortgage bonds due October 20, 2044. The closing for the sale of the first mortgage bonds for both utilities is anticipated to be October 1, 2014, subject to satisfaction of customary closing conditions.

Natural Gas Delivery Agreement

In 2012, we entered into a ten-year gas gathering and processing contract for natural gas production from our properties in the Piceance Basin in Colorado, under which we pay a gathering fee per Mcf. The contract requires us to deliver a minimum of 20,000 Mcf per day. This agreement became effective in first quarter of 2014 upon completion of the processing infrastructure capable of handling the committed volumes. We believe that our reserves dedicated to the gathering system, and the projected volumes are adequate to materially satisfy our delivery commitments under this agreement.

Turbine Sale Agreement

On May 6, 2013, Black Hills Wyoming entered into an agreement to sell its 40 MW CTII natural-gas fired generating unit to the City of Gillette, Wyoming for approximately \$22 million, upon expiration of the PPA with Cheyenne Light in August 2014. As part of the sale, Black Hills Wyoming will provide services to the City of Gillette through an economy energy PPA. The sale received FERC approval on July 14, 2014, and is expected to close by August 31, 2014.

Reimbursement Agreement

We have a reimbursement agreement in place with Wells Fargo on behalf of Cheyenne Light for the 2009A bonds of \$10 million due in 2027 and the 2009B bonds of \$7.0 million due in 2021. In the case of default, we hold the assumption of liability for drawings on Cheyenne Light's Letter of Credit attached to these bonds.

Other Commitments

Construction of Cheyenne Prairie, a 132 MW natural gas-fired electric generating facility jointly owned by Cheyenne Light and Black Hills Power is expected to cost approximately \$222 million. Construction is expected to be completed by September 30, 2014. As of June 30, 2014, committed contracts for equipment purchases and for construction were 100% and 98% complete, respectively.

Oil Creek Fire

On June 29, 2012, a forest and grassland fire occurred in the western Black Hills of Wyoming. A state fire investigator concluded that the fire was caused by the failure of a transmission structure owned, operated and maintained by Black Hills Power. On April 16, 2013, a lawsuit was filed in the United States District Court for the District of Wyoming, which forty-seven plaintiffs and the State of Wyoming have now joined, asserting claims for damages against Black Hills Power. The claims include allegations of negligence, negligence per se, common law nuisance, and trespass. In addition to claims for these compensatory damages, the lawsuit seeks recovery of punitive damages. Our investigation of the cause and origin of the fire is ongoing. We have denied and will vigorously defend all claims arising out of the fire, pending the completion of our investigation. We cannot predict the outcome of our investigation, the viability of alleged claims or the outcome of the litigation.

Civil litigation of this kind, however, is likely to lead to settlement negotiations, including negotiations prompted by pre-trial civil court procedures. We believe such negotiations would effect a settlement of all claims. Regardless of whether the litigation is determined at trial or through settlement, we expect to incur significant investigation, legal and expert services expenses associated with the litigation. We maintain insurance coverage to limit our exposure to losses due to civil liability claims, and related litigation expense. The deductible applicable to some types of claims arising out of this fire is \$1.0 million. We expect this coverage to limit our exposure, and we will pursue recoveries to the maximum extent available under the policies. Based upon information currently available, we believe that a loss associated with settlement of pending claims is probable. Accordingly, as of June 30, 2014, we recorded a loss contingency liability related to these claims, and we recorded a receivable for costs we believe are reimbursable and probable of recovery under our insurance coverage. Both of these entries reflect our reasonable estimate of probable future litigation expense and settlement costs; we did not base these contingencies on any determination that it is probable we would be found liable for these claims were they to be litigated.

Given the uncertainty of litigation, however, a loss related to the fire, the litigation and related claims in excess of the loss we have determined to be probable is reasonably possible. However, we cannot reasonably estimate the amount of such possible loss because our investigation and review of damage claims documentation is ongoing, and there are significant factual and legal issues to be resolved. Further claims may be presented by these and other parties. While we have received claims seeking recovery for fire suppression, reclamation and rehabilitation costs, damage to fencing and other personal property, alleged injury to timber, grass or hay, livestock and related operations, and diminished value of real estate, currently totaling \$50 million, we are not yet able, for the reasons described above, to reasonably estimate the amount of any reasonable possible losses in excess of the amount we have accrued. Based upon information currently available, however, management does not expect the outcome of the claims to have a material adverse effect upon our consolidated financial condition, results of operations or cash flows.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of June 30, 2014, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at June 30, 2014:

Our utilities are generally limited to the amount of dividends allowed to be paid to us as a utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of June 30, 2014, the restricted net assets at our Utilities Group were approximately \$141 million.

(15) GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include indemnification for reclamation and surety bonds.

We had the following guarantees in place (in thousands):

| Nature of Guarantee | Maximum Exposure at | |
|--|---------------------|------------|
| | June 30, 2014 | Expiration |
| Indemnification for subsidiary reclamation/surety bonds ⁽¹⁾ | \$65,744 | Ongoing |

We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered (1) into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Condensed Consolidated Balance Sheets.

During the second quarter, guarantees of Black Hills Utility Holdings' payment obligations up to \$70 million arising from commodity transactions for natural gas supply were removed, primarily due to improvement of the corporate credit rating, as well as the conversion of certain guarantees to letters of credit.

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

We are a growth-oriented, vertically-integrated 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 financial segments:

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

Our Utilities Group consists of our Electric and Gas Utilities segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 203,500 customers in South Dakota, Wyoming, Colorado and Montana; and also distributes natural gas to approximately 35,500 Cheyenne Light customers in Wyoming. Our Gas Utilities serve approximately 538,000 natural gas customers in Colorado, Iowa, Kansas and Nebraska. Our Non-regulated Energy Group consists of our Power Generation, Coal Mining and Oil and Gas segments. Our Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy principally to our utilities under long-term contracts. Our Coal Mining segment produces coal at our coal mine near Gillette, Wyoming and sells the coal primarily to on-site, mine-mouth power generation facilities. Our Oil and Gas segment engages in exploration, development and production of crude oil and natural gas, primarily in the Rocky Mountain region.

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2014 and 2013, and our financial condition as of June 30, 2014, December 31, 2013 and June 30, 2013, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period or for the entire year.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 59.

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

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013. Net income (loss) for the three months ended June 30, 2014 was \$20 million, or \$0.44 per share, compared to Net income (loss) of \$31 million, or \$0.69 per share, reported for the same period in 2013.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. Net income (loss) for the six months ended June 30, 2014 was \$68 million, or \$1.52 per share, compared to Net income (loss) of \$74 million, or \$1.66 per share, reported for the same period in 2013.

The following table summarizes select financial results by operating segment and details significant items (in thousands):

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|--|-----------------------------|-----------|------------|---------------------------|-----------|-----------|
| | 2014 | 2013 | Variance | 2014 | 2013 | Variance |
| Revenue | | | | | | |
| Utilities | \$264,383 | \$263,868 | \$515 | \$705,822 | \$626,310 | \$79,512 |
| Non-regulated Energy | 51,779 | 46,257 | 5,522 | 104,475 | 95,544 | 8,931 |
| Inter-company eliminations | (32,925) |)(30,299) |)(2,626) |)(66,891) |)(61,357) |)(5,534) |
| | \$283,237 | \$279,826 | \$3,411 | \$743,406 | \$660,497 | \$82,909 |
| Net income (loss) | | | | | | |
| Electric Utilities | \$11,427 | \$10,610 | \$817 | \$26,002 | \$22,966 | \$3,036 |
| Gas Utilities | 1,994 | 3,192 | (1,198) |)26,692 | 21,675 | 5,017 |
| Utilities | 13,421 | 13,802 | (381) |)52,694 | 44,641 | 8,053 |
| Power Generation | 7,194 | 5,031 | 2,163 | 15,267 | 10,675 | 4,592 |
| Coal Mining | 2,016 | 1,973 | 43 | 4,480 | 3,038 | 1,442 |
| Oil and Gas | (1,660) |)(1,964) |)304 | (3,682) |)(2,017) |)(1,665) |
| Non-regulated Energy | 7,550 | 5,040 | 2,510 | 16,065 | 11,696 | 4,369 |
| Corporate activities and eliminations (a) | (1,151) |)(11,676) | (12,827) |)(821) |)17,378 | (18,199) |
| Net income (loss) | \$19,820 | \$30,518 | \$(10,698) |)\$67,938 | \$73,715 | \$(5,777) |

Corporate activities for the three and six months ended June 30, 2013 include a \$12 million and a \$17 million net (a) after-tax non-cash mark-to-market gain on certain interest rate swaps. These same interest rate swaps were settled in November 2013.

Overview of Business Segments and Corporate Activity

Utilities Group

Gas Utilities experienced milder weather during the three months ended June 30, 2014 resulting in a 16% decrease in heating degree days compared to the same period in 2013. Year-to-date results were favorably impacted by colder weather during the first quarter of 2014. Heating degree days were 2% higher for the six months ended June 30, 2014, compared to the same period in 2013. Heating degree days for the three and six months ended June 30, 2014 were 5% and 12% higher than normal, respectively, compared to 24% and 9% higher than normal for the same periods in 2013.

Construction continued on Cheyenne Prairie, a natural gas-fired electric generating facility to serve Cheyenne Light and Black Hills Power customers. The 132 MW generation project is expected to cost approximately \$222 million, exclusive of construction financing costs which are being recovered through construction financing riders. The Electric Utilities recorded additional gross margins of approximately \$3.7 million and \$7.8 million, respectively, for the three and six months ended June 30, 2014, related to these riders. To date, we have expended approximately \$196 million. The project is expected to be completed at or less than budget and is on schedule to be placed into service in October 2014.

On July 31, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Cheyenne Light of \$8.4 million and \$0.8 million for annual electric and natural gas revenue, respectively, effective October 1, 2014. The settlement also included a return on equity of 9.9%, and a capital structure of 54% equity and 46% debt.

- On July 22, 2014, Black Hills Power filed a CPCN with the WPSC to construct the Wyoming portion of a \$54 million, 230-kV, 144 mile-long transmission line that would connect the Teckla Substation in northeast Wyoming, to the Lange Substation near Rapid City, South Dakota. On June 30, 2014, Black Hills Power filed an application with the SDPUC, for a permit to construct the South Dakota portion of this line. Approval by the WPSC and SDPUC is anticipated in the fourth quarter of 2014.

On June 30, 2014, Black Hills Power and Cheyenne Light entered into agreements to issue \$160 million of first mortgage bonds to finance Cheyenne Prairie. Black Hills Power will issue \$85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light will issue \$75 million of 4.53% coupon first mortgage bonds due October 20, 2044. The closing for the sale of the first mortgage bonds for both utilities is anticipated to be October 1, 2014, subject to satisfaction of customary closing conditions.

- On May 5, 2014, Colorado Electric issued an all-source generation request for approximately 42 MW of summer seasonal firm capacity in 2017, 2018, and 2019, and up to 60 MW of eligible renewable energy resources to serve its customers in southern Colorado. Colorado IPP submitted solar and wind bids in response to this request. Proposed bids were due by July 31, 2014, and pending Colorado Electric's review of the bids and other regulatory proceedings, a CPUC decision on Colorado Electric's portfolio of generation resources is expected by the end of February 2015.

On April 30, 2014, Colorado Electric filed a rate request with the CPUC for an annual revenue increase of \$8.0 million to recover operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm. Colorado Electric seeks approval of a new rider pursuant to the Clean Air-Clean Jobs Act Adjustment, to recover a return on the expenditures associated with the construction of a \$65 million natural gas-fired combustion turbine unit, previously approved by the CPUC to replace the W.N. Clark retirement. The filing seeks a return on equity of 10.3% and a capital structure of approximately 50.5% equity and 49.5% debt. A subsequent filing on June 27, 2014 reduced our request to \$7.2 million to reflect updated cost information.

On April 29, 2014, Kansas Gas filed a rate request with the KCC to increase annual revenue by \$7.3 million primarily to recover infrastructure and increased operating costs. The filing seeks a return on equity of 10.6%, and a capital structure of approximately 50.3% equity and 49.7% debt.

On April 25, 2014 Cheyenne Light received FERC approval to establish rates for transmission services under their Open Access Transmission Tariff, effective May 3, 2014. The approval includes a return on equity of 10.6% and a capital structure of 54% equity and 46% debt.

On March 31, 2014, Black Hills Power filed a rate request with the SDPUC to increase annual revenue by \$14.6 million to recover operating expenses and infrastructure investments, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25%, and a capital structure of approximately 53.3% equity and 46.7% debt.

On March 21, 2014, Black Hills Power retired the Ben French, Neil Simpson I, and Osage coal-fired power plants. These three plants totaling 81 MW were closed because of federal environmental regulations. These plants will largely be replaced by Black Hills Power's share of Cheyenne Prairie.

On February 25, 2014, the CPUC issued a final order after rehearing, approving a CPCN for the retirement of Pueblo Unit #5 and #6, effective December 31, 2013.

On January 17, 2014, Black Hills Power filed a rate request with the WPSC for an annual revenue increase of \$2.8 million to recover investments made in electric infrastructure, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25% and a capital structure of approximately 53.3% equity and 46.7% debt.

Our Utilities Group continued its efforts to acquire small municipal gas distribution systems adjacent to our existing service territories. During the first quarter of 2014, we acquired an additional gas system, adding approximately 70 customers, and we announced the pending acquisition of assets serving approximately 400 customers.

Non-regulated Energy Group

Oil and Gas production volumes increased 15% and 5%, respectively, for the three and six months ended June 30, 2014. The average hedged price received increased for natural gas by 35% and 24% and decreased for oil by 18% and 8%, respectively for the three and six months ended June 30, 2014 compared to the same periods in 2013.

On July 14, 2014, Black Hills Wyoming received FERC approval for the sale of its 40 MW CTII natural gas-fired unit to the City of Gillette, Wyoming for approximately \$22 million. The sale is expected to close on August 31, 2014 upon expiration of the PPA with Cheyenne Light.

Drilling commenced in June 2014 in the southern Piceance Basin on two of the six horizontal Mancos Shale wells planned for 2014.

Production continued from the two horizontal Mancos Shale wells placed on production during the first quarter of 2014. On March 6, 2014, the Summit Midstream cryogenic gas processing plant with a capacity of 20,000 Mcf per day started serving the company's gas production in the southern Piceance Basin, including the two Mancos Shale wells placed on production during the first quarter.

Corporate Activities

On June 13, 2014, Fitch upgraded the BHC credit rating to BBB+ with a stable outlook.

On May 29, 2014, we amended our \$500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to \$750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options for which the borrowing rates were reduced under the amended agreement.

On January 30, 2014, Moody's upgraded our corporate credit rating to Baa1 from Baa2 with continued stable outlook.

Consolidated interest expense decreased by approximately \$5.5 million and \$11 million for the three and six months ended June 30, 2014, respectively, compared to the three and six months ended June 30, 2013, due primarily to the refinancing activities occurring during the fourth quarter of 2013.

Operating Results

A discussion of operating results from our segments and Corporate activities follows.

33

Utilities Group

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

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, gross margin, that is considered a “non-GAAP financial measure.” Generally, a non-GAAP financial measure is a numerical measure of a company’s financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of gross margin is intended to supplement investors’ understanding of our operating performance.

Gross margin for our Electric Utilities is calculated as operating revenue less cost of fuel, purchased power and cost of natural gas sold. Gross margin for our Gas Utilities is calculated as operating revenues less cost of natural gas sold. Our gross margin is impacted by the fluctuations in power purchases and natural gas and other fuel supply costs. However, while these fluctuating costs impact gross margin as a percentage of revenue, they only impact total gross margin if the costs cannot be passed through to our customers.

Our gross margin measure may not be comparable to other companies’ gross margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|--|-----------------------------|-----------|----------|---------------------------|-----------|----------|
| | 2014 | 2013 | Variance | 2014 | 2013 | Variance |
| | (in thousands) | | | | | |
| Revenue — electric | \$154,544 | \$151,775 | \$2,769 | \$322,909 | \$302,148 | \$20,761 |
| Revenue — gas | 7,340 | 6,257 | 1,083 | 21,077 | 18,514 | 2,563 |
| Total revenue | 161,884 | 158,032 | 3,852 | 343,986 | 320,662 | 23,324 |
| Fuel, purchased power and cost of gas — electric | 69,723 | 67,349 | 2,374 | 148,142 | 133,038 | 15,104 |
| Purchased gas — gas | 4,051 | 2,515 | 1,536 | 12,325 | 8,953 | 3,372 |
| Total fuel, purchased power and cost of gas | 73,774 | 69,864 | 3,910 | 160,467 | 141,991 | 18,476 |
| Gross margin — electric | 84,821 | 84,426 | 395 | 174,767 | 169,110 | 5,657 |
| Gross margin — gas | 3,289 | 3,742 | (453) |)8,752 | 9,561 | (809) |
| Total gross margin | 88,110 | 88,168 | (58) |)183,519 | 178,671 | 4,848 |
| Operations and maintenance | 40,272 | 39,383 | 889 | 82,872 | 78,218 | 4,654 |
| Depreciation and amortization | 19,274 | 19,665 | (391) |)38,361 | 38,826 | (465) |
| Total operating expenses | 59,546 | 59,048 | 498 | 121,233 | 117,044 | 4,189 |

Edgar Filing: BLACK HILLS CORP /SD/ - Form 10-Q

| | | | | | | |
|------------------------------|----------|----------|--------|----------|----------|---------|
| Operating income | 28,564 | 29,120 | (556 |)62,286 | 61,627 | 659 |
| Interest expense, net | (11,829 |)(13,810 |)1,981 | (23,841 |)(28,207 |)4,366 |
| Other income (expense), net | 352 | 173 | 179 | 608 | 458 | 150 |
| Income tax benefit (expense) | (5,660 |)(4,873 |)(787 |)(13,051 |)(10,912 |)(2,139 |
| Net income (loss) | \$11,427 | \$10,610 | \$817 | \$26,002 | \$22,966 | \$3,036 |

34

Edgar Filing: BLACK HILLS CORP /SD/ - Form 10-Q

| Revenue - Electric (in thousands) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|-----------------------------|------------|---------------------------|------------|
| | 2014 | 2013 | 2014 | 2013 |
| Residential: | | | | |
| Black Hills Power | \$ 14,332 | \$ 13,535 | \$ 34,392 | \$ 29,977 |
| Cheyenne Light | 8,167 | 8,307 | 17,840 | 17,637 |
| Colorado Electric | 21,316 | 21,829 | 45,995 | 45,950 |
| Total Residential | 43,815 | 43,671 | 98,227 | 93,564 |
| Commercial: | | | | |
| Black Hills Power | 21,200 | 18,913 | 42,728 | 36,397 |
| Cheyenne Light | 15,238 | 14,476 | 29,631 | 27,243 |
| Colorado Electric | 23,101 | 21,663 | 44,991 | 42,814 |
| Total Commercial | 59,539 | 55,052 | 117,350 | 106,454 |
| Industrial: | | | | |
| Black Hills Power | 7,534 | 7,210 | 14,869 | 13,220 |
| Cheyenne Light | 7,304 | 5,344 | 14,528 | 10,199 |
| Colorado Electric | 9,535 | 9,647 | 18,573 | 19,284 |
| Total Industrial | 24,373 | 22,201 | 47,970 | 42,703 |
| Municipal: | | | | |
| Black Hills Power | 846 | 847 | 1,638 | 1,561 |
| Cheyenne Light | 514 | 490 | 968 | 948 |
| Colorado Electric | 3,277 | 3,492 | 6,584 | 6,039 |
| Total Municipal | 4,637 | 4,829 | 9,190 | 8,548 |
| Total Retail Revenue - Electric | 132,364 | 125,753 | 272,737 | 251,269 |
| Contract Wholesale: | | | | |
| Total Contract Wholesale - Black Hills Power | 4,473 | 4,926 | 10,071 | 10,693 |
| Off-system Wholesale: | | | | |
| Black Hills Power | 5,411 | 7,849 | 14,486 | 14,099 |
| Cheyenne Light | 1,787 | 2,094 | 4,174 | 4,776 |
| Colorado Electric | 1,912 | 2,133 | 3,995 | 3,240 |
| Total Off-system Wholesale | 9,110 | 12,076 | 22,655 | 22,115 |
| Other Revenue: | | | | |
| Black Hills Power | 6,945 | 7,552 | 13,823 | 14,702 |
| Cheyenne Light | 534 | 482 | 1,287 | 1,048 |
| Colorado Electric | 1,118 | 986 | 2,336 | 2,321 |
| Total Other Revenue | 8,597 | 9,020 | 17,446 | 18,071 |
| Total Revenue - Electric | \$ 154,544 | \$ 151,775 | \$ 322,909 | \$ 302,148 |

| Quantities Generated and Purchased (in MWh) | Three Months Ended | | Six Months Ended | |
|---|--------------------|-----------|------------------|-----------|
| | June 30, 2014 | 2013 | June 30, 2014 | 2013 |
| Generated — | | | | |
| Coal-fired: | | | | |
| Black Hills Power ^(a) | 336,842 | 450,097 | 754,090 | 877,112 |
| Cheyenne Light | 162,847 | 155,384 | 332,636 | 327,696 |
| Colorado Electric | — | — | — | — |
| Total Coal-fired | 499,689 | 605,481 | 1,086,726 | 1,204,808 |
| Natural Gas and Oil: | | | | |
| Black Hills Power | 2,665 | 4,558 | 4,972 | 7,678 |
| Cheyenne Light | — | — | — | — |
| Colorado Electric ^(b) | 40,599 | 107,535 | 58,668 | 138,589 |
| Total Natural Gas and Oil | 43,264 | 112,093 | 63,640 | 146,267 |
| Wind: | | | | |
| Colorado Electric | 13,230 | 11,834 | 27,558 | 23,007 |
| Total Wind | 13,230 | 11,834 | 27,558 | 23,007 |
| Total Generated: | | | | |
| Black Hills Power | 339,507 | 454,655 | 759,062 | 884,790 |
| Cheyenne Light | 162,847 | 155,384 | 332,636 | 327,696 |
| Colorado Electric | 53,829 | 119,369 | 86,226 | 161,596 |
| Total Generated | 556,183 | 729,408 | 1,177,924 | 1,374,082 |
| Purchased — | | | | |
| Black Hills Power | 365,463 | 349,183 | 796,265 | 737,382 |
| Cheyenne Light | 197,225 | 205,027 | 404,543 | 406,872 |
| Colorado Electric ^(b) | 467,197 | 412,037 | 937,299 | 867,175 |
| Total Purchased | 1,029,885 | 966,247 | 2,138,107 | 2,011,429 |
| Total Generated and Purchased: | | | | |
| Black Hills Power | 704,970 | 803,838 | 1,555,327 | 1,622,172 |
| Cheyenne Light | 360,072 | 360,411 | 737,179 | 734,568 |
| Colorado Electric | 521,026 | 531,406 | 1,023,525 | 1,028,771 |
| Total Generated and Purchased | 1,586,068 | 1,695,655 | 3,316,031 | 3,385,511 |

(a) Decrease reflects the retirement of Neil Simpson I on March 21, 2014.

Decrease reflects a current year unplanned outage due to a turbine bearing replacement and combustor upgrade at (b) Pueblo Airport Generation Station, and utilization of Pueblo Airport Generating Station Units #1 and #2 in place of purchased power from Colorado IPP during the six months ended June 30 2013.

Edgar Filing: BLACK HILLS CORP /SD/ - Form 10-Q

| Quantity (in MWh) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|-----------------------------|------------------|---------------------------|------------------|
| | 2014 | 2013 | 2014 | 2013 |
| Residential: | | | | |
| Black Hills Power | 107,394 | 113,525 | 278,704 | 274,495 |
| Cheyenne Light | 57,328 | 60,669 | 127,983 | 136,125 |
| Colorado Electric | 132,256 | 140,755 | 285,887 | 296,191 |
| Total Residential | 296,978 | 314,949 | 692,574 | 706,811 |
| Commercial: | | | | |
| Black Hills Power | 176,541 | 174,763 | 360,989 | 350,380 |
| Cheyenne Light | 129,688 | 132,214 | 256,100 | 261,643 |
| Colorado Electric | 174,239 | 180,340 | 332,418 | 351,045 |
| Total Commercial | 480,468 | 487,317 | 949,507 | 963,068 |
| Industrial: | | | | |
| Black Hills Power | 104,914 | 105,856 | 205,765 | 197,488 |
| Cheyenne Light | 94,861 | 65,716 | 185,586 | 135,668 |
| Colorado Electric | 111,090 | 92,867 | 201,207 | 171,416 |
| Total Industrial | 310,865 | 264,439 | 592,558 | 504,572 |
| Municipal: | | | | |
| Black Hills Power | 7,709 | 8,147 | 15,394 | 15,930 |
| Cheyenne Light | 2,131 | 2,143 | 4,624 | 4,738 |
| Colorado Electric | 31,385 | 29,049 | 58,073 | 47,095 |
| Total Municipal | 41,225 | 39,339 | 78,091 | 67,763 |
| Total Retail Quantity Sold | 1,129,536 | 1,106,044 | 2,312,730 | 2,242,214 |
| Contract Wholesale: | | | | |
| Total Contract Wholesale - Black Hills Power | 71,999 | 77,653 | 167,227 | 181,437 |
| Off-system Wholesale: | | | | |
| Black Hills Power | 169,498 | 277,840 | 424,294 | 516,287 |
| Cheyenne Light | 42,250 | 61,514 | 94,606 | 131,822 |
| Colorado Electric | 50,178 | 38,238 | 80,924 | 70,015 |
| Total Off-system Wholesale | 261,926 | 377,592 | 599,824 | 718,124 |
| Total Quantity Sold: | | | | |
| Black Hills Power | 638,055 | 757,784 | 1,452,373 | 1,536,017 |
| Cheyenne Light | 326,258 | 322,256 | 668,899 | 669,996 |
| Colorado Electric | 499,148 | 481,249 | 958,509 | 935,762 |
| Total Quantity Sold | 1,463,461 | 1,561,289 | 3,079,781 | 3,141,775 |
| Other Uses, Losses or Generation, net ^(a): | | | | |
| Black Hills Power | 66,915 | 46,054 | 102,954 | 86,155 |
| Cheyenne Light | 33,814 | 38,155 | 68,280 | 64,572 |
| Colorado Electric | 21,878 | 50,157 | 65,016 | 93,009 |
| Total Other Uses, Losses and Generation, net | 122,607 | 134,366 | 236,250 | 243,736 |

| | | | | |
|--------------|-----------|-----------|-----------|-----------|
| Total Energy | 1,586,068 | 1,695,655 | 3,316,031 | 3,385,511 |
|--------------|-----------|-----------|-----------|-----------|

(a) Includes company uses, line losses, and excess exchange production.

37

| Degree Days | Three Months Ended June 30, | | 2013 | | Variance from | |
|--|-----------------------------|-----------------|---------|---------------------------|-----------------|----|
| | 2014 | Variance from | Actual | Variance from | 30-Year Average | |
| | Actual | 30-Year Average | | Actual | 30-Year Average | |
| Heating Degree Days: | | | | | | |
| Black Hills Power | 1,025 | 2 | % 1,227 | 43 | | % |
| Cheyenne Light | 1,191 | — | % 1,321 | 11 | | % |
| Colorado Electric | 633 | 4 | % 752 | (1) | |)% |
| Combined | 877 | 2 | % 1,026 | 19 | | % |
| Cooling Degree Days: | | | | | | |
| Black Hills Power | 99 | (7 |)% 78 | (27 | |)% |
| Cheyenne Light | 50 | (2 |)% 123 | 141 | | % |
| Colorado Electric | 209 | (8 |)% 376 | 66 | | % |
| Combined | 140 | (7 |)% 225 | 48 | | % |
| Six Months Ended June 30, | | | | | | |
| Degree Days | 2014 | | 2013 | | Variance from | |
| | Actual | Variance from | Actual | Variance from | 30-Year Average | |
| | Actual | 30-Year Average | | Actual | 30-Year Average | |
| Heating Degree Days: | | | | | | |
| Black Hills Power | 4,435 | 5 | % 4,437 | 9 | | % |
| Cheyenne Light | 4,397 | 4 | % 4,483 | 6 | | % |
| Colorado Electric | 3,303 | 3 | % 3,502 | 4 | | % |
| Combined | 3,905 | 4 | % 4,012 | 6 | | % |
| Cooling Degree Days: | | | | | | |
| Black Hills Power | 99 | (7 |)% 78 | (27 | |)% |
| Cheyenne Light | 50 | (2 |)% 123 | 141 | | % |
| Colorado Electric | 209 | (9 |)% 376 | 66 | | % |
| Combined | 140 | (7 |)% 225 | 49 | | % |
| Electric Utilities Power Plant Availability | | | | | | |
| Availability | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
| | 2014 | 2013 | | 2014 | 2013 | |
| Coal-fired plants ^(a) | 84.8 | % 96.0 | % | 90.1 | % 96.4 | % |
| Other plants ^{(b)(c)} | 89.9 | % 95.5 | % | 84.0 | % 97.1 | % |
| Total availability | 87.7 | % 95.7 | % | 86.6 | % 96.7 | % |

(a) The three months and six months ended June 30, 2014 reflect a planned annual outage at Neil Simpson II and an unplanned outage for a catalyst repair at Wygen III.

(b) The three months and six months ended June 30, 2014 include a planned outage at Ben French CT's #1 and #2 for a controls upgrade.

(c) The six months ended June 30, 2014, reflects an unplanned outage due to a turbine bearing replacement and combustor upgrade at Pueblo Airport Generation Station.

Cheyenne Light Natural Gas Distribution

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---------------------------------------|-----------------------------|---------|---------------------------|-----------|
| | 2014 | 2013 | 2014 | 2013 |
| Revenue - Natural Gas (in thousands): | | | | |
| Residential | \$4,519 | \$4,033 | \$12,743 | \$11,565 |
| Commercial | 1,975 | 1,522 | 5,951 | 5,130 |
| Industrial | 616 | 505 | 1,903 | 1,403 |
| Other Sales Revenue | 230 | 197 | 480 | 416 |
| Total Revenue - Natural Gas | \$7,340 | \$6,257 | \$21,077 | \$18,514 |
| Gross Margin (in thousands): | | | | |
| Residential | \$2,383 | \$2,674 | \$5,987 | \$6,634 |
| Commercial | 631 | 748 | 1,962 | 2,240 |
| Industrial | 47 | 123 | 323 | 271 |
| Other Gross Margin | 228 | 197 | 480 | 416 |
| Total Gross Margin | \$3,289 | \$3,742 | \$8,752 | \$9,561 |
| Volumes Sold (Dth): | | | | |
| Residential | 450,715 | 492,261 | 1,485,892 | 1,585,261 |
| Commercial | 284,493 | 278,914 | 848,887 | 904,851 |
| Industrial | 120,558 | 137,212 | 376,485 | 364,159 |
| Total Volumes Sold | 855,766 | 908,387 | 2,711,264 | 2,854,271 |

Results of Operations for the Electric Utilities for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net income for the Electric Utilities was \$11 million for the three months ended June 30, 2014, compared to \$11 million for the three months ended June 30, 2013, as a result of:

Gross margin was comparable to the prior year, reflecting increased rider margins of \$2.2 million due to a return on additional investment in our generating facilities. Industrial megawatt hours sold increased 18% compared to the same period in the prior year, primarily driven by load growth at Cheyenne Light. These increases were offset by a 38% decrease in cooling degree days compared to the same period in the prior year resulting in a \$1.6 million decrease on lower residential and commercial megawatt hours sold, and a \$0.6 million decrease in wholesale power volumes as a result of plant outages. Our Cheyenne Light gas utility experienced an 11% decrease in heating degree days, primarily from April, resulting in a \$0.5 million decrease in retail natural gas sales.

Operations and maintenance increased primarily due to increases in employee costs, regulatory support, and property taxes.

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

Interest expense, net decreased primarily due to lower interest rates from refinancing higher cost debt in the fourth quarter of 2013.

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

Income tax benefit (expense): The effective tax rate is higher in 2014 primarily due to the research and development tax credit not being extended to 2014.

Results of Operations for the Electric Utilities for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net income for the Electric Utilities was \$26 million for the six months ended June 30, 2014, compared to \$23 million for the six months ended June 30, 2013, as a result of:

Gross margin increased primarily due to a return on additional investments which increased base electric margins by \$4.0 million and increased rider margins by \$5.8 million. Industrial megawatt hours sold increased by approximately 18 percent, primarily due to load growth at Cheyenne Light. These increases are partially offset by a \$1.8 million decrease from lower residential and commercial megawatt hours sold driven by a 38% decrease in cooling degree days compared to the same period in the prior year, a \$1.0 million decrease in wholesale volumes sold, a \$0.9 million decrease from the TCA, and a \$0.5 million decrease from a construction savings incentive recognized in the prior year. Our Cheyenne Light gas utility experienced a decrease in heating degree days, resulting in a \$0.8 million decrease in retail natural gas sales.

Operations and maintenance increased primarily due to an increase in employee costs, generation maintenance, regulatory support and property taxes.

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

Interest expense, net decreased primarily due to refinancing higher cost debt in the fourth quarter of 2013.

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

Income tax benefit (expense): The effective tax rate is higher in 2014 primarily due to the research and development tax credit not being extended to 2014. The prior year reflected the entire year of the 2012 research and development tax credit due to retroactive reinstatement of the credit in January 2013 by the U.S. Congress.

Gas Utilities

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|--------------------------------|-----------------------------|----------|-----------|---------------------------|-----------|----------|
| | 2014 | 2013 | Variance | 2014 | 2013 | Variance |
| | (in thousands) | | | | | |
| Natural gas — regulated | \$95,350 | \$98,635 | \$(3,285) |)\$346,582 | \$290,586 | \$55,996 |
| Other — non-regulated services | 7,149 | 7,201 | (52) |)15,254 | 15,062 | 192 |
| Total revenue | 102,499 | 105,836 | (3,337) |)361,836 | 305,648 | 56,188 |
| Natural gas — regulated | 52,266 | 53,143 | (877) |)223,040 | 173,523 | 49,517 |
| Other — non-regulated services | 3,675 | 3,517 | 158 |)7,397 | 7,234 | 163 |
| Total cost of sales | 55,941 | 56,660 | (719) |)230,437 | 180,757 | 49,680 |
| Gross margin | 46,558 | 49,176 | (2,618) |)131,399 | 124,891 | 6,508 |
| Operations and maintenance | 33,454 | 31,852 | 1,602 |)68,832 | 65,078 | 3,754 |
| Depreciation and amortization | 6,538 | 6,583 | (45) |)13,059 | 13,086 | (27) |
| Total operating expenses | 39,992 | 38,435 | 1,557 |)81,891 | 78,164 | 3,727 |
| Operating income (loss) | 6,566 | 10,741 | (4,175) |)49,508 | 46,727 | 2,781 |
| Interest expense, net | (3,722) |)(5,907) |)2,185 | (7,574) |)(12,184) |)4,610 |
| Other income (expense), net | 19 | (5) |)24 | 1 | 7 | (6) |
| Income tax benefit (expense) | (869) |)(1,637) |)768 | (15,243) |)(12,875) |)(2,368) |
| Net income (loss) | \$1,994 | \$3,192 | \$(1,198) |)\$26,692 | \$21,675 | \$5,017 |

| Revenue (in thousands) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|-----------------------------|-----------------------------|-----------|---------------------------|-----------|
| | 2014 | 2013 | 2014 | 2013 |
| Residential: | | | | |
| Colorado | \$9,435 | \$9,850 | \$33,122 | \$29,644 |
| Nebraska | 17,519 | 22,932 | 80,411 | 71,784 |
| Iowa | 22,052 | 18,139 | 76,816 | 56,890 |
| Kansas | 10,348 | 12,620 | 43,625 | 38,385 |
| Total Residential | 59,354 | 63,541 | 233,974 | 196,703 |
| Commercial: | | | | |
| Colorado | 2,060 | 1,778 | 6,757 | 5,438 |
| Nebraska | 4,590 | 7,098 | 24,656 | 23,345 |
| Iowa | 11,202 | 8,442 | 37,116 | 26,217 |
| Kansas | 3,624 | 4,052 | 15,295 | 12,841 |
| Total Commercial | 21,476 | 21,370 | 83,824 | 67,841 |
| Industrial: | | | | |
| Colorado | 504 | 507 | 581 | 555 |
| Nebraska | 99 | 100 | 307 | 305 |
| Iowa | 1,141 | 709 | 2,313 | 1,454 |
| Kansas | 5,632 | 6,068 | 6,718 | 7,000 |
| Total Industrial | 7,376 | 7,384 | 9,919 | 9,314 |
| Transportation: | | | | |
| Colorado | 217 | 227 | 542 | 628 |
| Nebraska | 2,542 | 2,395 | 8,272 | 7,111 |
| Iowa | 983 | 999 | 2,744 | 2,538 |
| Kansas | 1,563 | 1,453 | 4,056 | 3,502 |
| Total Transportation | 5,305 | 5,074 | 15,614 | 13,779 |
| Other Sales Revenue: | | | | |
| Colorado | 36 | 22 | 67 | (52) |
| Nebraska | 651 | 626 | 1,354 | 1,240 |
| Iowa | 262 | 190 | 414 | 302 |
| Kansas | 890 | 428 | 1,416 | 1,459 |
| Total Other Sales Revenue | 1,839 | 1,266 | 3,251 | 2,949 |
| Total Regulated Revenue | 95,350 | 98,635 | 346,582 | 290,586 |
| Non-regulated Services | 7,149 | 7,201 | 15,254 | 15,062 |
| Total Revenue | \$102,499 | \$105,836 | \$361,836 | \$305,648 |

| Gross Margin (in thousands) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|------------------------------|-----------------------------|----------|---------------------------|-----------|
| | 2014 | 2013 | 2014 | 2013 |
| Residential: | | | | |
| Colorado | \$3,597 | \$3,884 | \$9,969 | \$10,122 |
| Nebraska | 9,925 | 11,055 | 30,814 | 29,366 |
| Iowa | 8,993 | 9,397 | 24,203 | 22,986 |
| Kansas | 6,529 | 6,925 | 18,113 | 17,129 |
| Total Residential | 29,044 | 31,261 | 83,099 | 79,603 |
| Commercial: | | | | |
| Colorado | 607 | 579 | 1,667 | 1,568 |
| Nebraska | 1,772 | 2,292 | 6,935 | 6,927 |
| Iowa | 2,300 | 2,592 | 7,525 | 7,044 |
| Kansas | 1,495 | 1,519 | 4,678 | 4,163 |
| Total Commercial | 6,174 | 6,982 | 20,805 | 19,702 |
| Industrial: | | | | |
| Colorado | 130 | 158 | 160 | 188 |
| Nebraska | 33 | 31 | 101 | 85 |
| Iowa | 61 | 81 | 146 | 163 |
| Kansas | 696 | 750 | 932 | 974 |
| Total Industrial | 920 | 1,020 | 1,339 | 1,410 |
| Transportation: | | | | |
| Colorado | 216 | 227 | 542 | 628 |
| Nebraska | 2,541 | 2,395 | 8,272 | 7,111 |
| Iowa | 982 | 999 | 2,743 | 2,538 |
| Kansas | 1,563 | 1,453 | 4,056 | 3,502 |
| Total Transportation | 5,302 | 5,074 | 15,613 | 13,779 |
| Other Sales Margins: | | | | |
| Colorado | 37 | 22 | 68 | (52) |
| Nebraska | 653 | 626 | 1,356 | 1,240 |
| Iowa | 263 | 190 | 414 | 302 |
| Kansas | 692 | 318 | 849 | 1,079 |
| Total Other Sales Margins | 1,645 | 1,156 | 2,687 | 2,569 |
| Total Regulated Gross Margin | 43,085 | 45,493 | 123,543 | 117,063 |
| Non-regulated Services | 3,473 | 3,683 | 7,856 | 7,828 |
| Total Gross Margin | \$46,558 | \$49,176 | \$131,399 | \$124,891 |

| Distribution Quantities Sold and Transportation (in Dth) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|-----------------------------|-------------------|---------------------------|-------------------|
| | 2014 | 2013 | 2014 | 2013 |
| Residential: | | | | |
| Colorado | 1,018,966 | 1,268,892 | 4,040,400 | 4,190,227 |
| Nebraska | 1,278,283 | 2,056,892 | 8,264,576 | 7,794,565 |
| Iowa | 1,249,921 | 1,732,786 | 7,892,965 | 7,023,152 |
| Kansas | 715,890 | 1,044,593 | 4,597,445 | 4,260,899 |
| Total Residential | 4,263,060 | 6,103,163 | 24,795,386 | 23,268,843 |
| Commercial: | | | | |
| Colorado | 255,312 | 256,317 | 891,002 | 832,593 |
| Nebraska | 485,023 | 836,828 | 2,960,179 | 3,035,626 |
| Iowa | 884,997 | 1,164,878 | 4,370,689 | 3,970,551 |
| Kansas | 391,548 | 474,953 | 1,933,515 | 1,752,087 |
| Total Commercial | 2,016,880 | 2,732,976 | 10,155,385 | 9,590,857 |
| Industrial: | | | | |
| Colorado | 101,468 | 127,124 | 111,793 | 136,861 |
| Nebraska | 12,168 | 13,585 | 39,133 | 44,265 |
| Iowa | 119,710 | 129,772 | 313,573 | 272,096 |
| Kansas | 1,084,608 | 1,222,845 | 1,264,695 | 1,411,666 |
| Total Industrial | 1,317,954 | 1,493,326 | 1,729,194 | 1,864,888 |
| Wholesale and Other: | | | | |
| Kansas | 32,274 | 19,199 | 100,907 | 74,209 |
| Total Wholesale and Other | 32,274 | 19,199 | 100,907 | 74,209 |
| Total Distribution Quantities Sold | 7,630,168 | 10,348,664 | 36,780,872 | 34,798,797 |
| Transportation: | | | | |
| Colorado | 209,799 | 216,333 | 540,143 | 629,042 |
| Nebraska | 6,623,555 | 6,040,006 | 16,586,774 | 14,722,321 |
| Iowa | 4,319,339 | 4,790,583 | 10,476,705 | 10,469,740 |
| Kansas | 3,594,159 | 3,336,618 | 8,421,296 | 7,388,636 |
| Total Transportation | 14,746,852 | 14,383,540 | 36,024,918 | 33,209,739 |
| Total Distribution Quantities Sold and Transportation | 22,377,020 | 24,732,204 | 72,805,790 | 68,008,536 |

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

| | Three Months Ended June 30, 2014 | | 2013 | | | |
|-------------------------|-------------------------------------|-------------------------------------|---------|-------------------------------------|---|--|
| | Actual | Variance from 30-Year Average | Actual | Variance from 30-Year Average | | |
| Heating Degree Days: | | | | | | |
| Colorado | 924 | — | % 972 | 5 | % | |
| Nebraska | 580 | 1 | % 769 | 33 | % | |
| Iowa | 775 | 11 | % 873 | 27 | % | |
| Kansas ^(a) | 480 | 7 | % 636 | 42 | % | |
| Combined ^(b) | 711 | 5 | % 842 | 24 | % | |
| | | | | | | |
| | Six Months Ended June 30, 2014 | | 2013 | | | |
| | Actual | Variance from 30-Year Average | Actual | Variance from 30-Year Average | | |
| Heating Degree Days: | | | | | | |
| Colorado | 3,783 | 2 | % 3,844 | 4 | % | |
| Nebraska | 3,852 | 6 | % 3,898 | 8 | % | |
| Iowa | 4,949 | 18 | % 4,616 | 14 | % | |
| Kansas ^(a) | 3,169 | 8 | % 3,186 | 9 | % | |
| Combined ^(b) | 4,235 | 12 | % 4,148 | 9 | % | |

^(a) Kansas Gas has an approved weather normalization mechanism within its rate structure, which minimizes weather impact on gross margins.

^(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas due to its weather normalization mechanism.

Results of Operations for the Gas Utilities for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net income for the Gas Utilities was \$2.0 million for the three months ended June 30, 2014, compared to Net income of \$3.2 million for the three months ended June 30, 2013, as a result of:

Gross margin decreased primarily due to milder weather compared to the same period in the prior year resulting in lower residential and commercial volumes sold. Heating degree days were 16% lower for the three months ended June 30, 2014, compared to the same period in the prior year and 5% higher than normal.

Operations and maintenance increased primarily due to an increase in employee costs.

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

Interest expense, net decreased primarily due to lower interest rates from refinancing higher cost debt in the fourth quarter of 2013.

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

Income tax benefit (expense): The effective tax rate for 2014 was slightly lower than 2013 due primarily to an increase in an estimated flow-through tax adjustment.

Results of Operations for the Gas Utilities for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net income for the Gas Utilities was \$26.7 million for the six months ended June 30, 2014, compared to Net income of \$21.7 million for the six months ended June 30, 2013, as a result of:

Gross margin increased primarily due to higher residential and commercial consumption, and transport volumes sold driven primarily by a 7% increase in heating degree days experienced through the peak months of the winter heating season as compared to the same period last year. Heating degree days were 2% higher for the six months ended June 30, 2014, compared to the same period in the prior year and 12% higher than normal.

Operations and maintenance increased primarily due to an increase in employee costs and property taxes.

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

Interest expense, net decreased primarily due to refinancing higher cost debt in the fourth quarter of 2013.

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

Income tax benefit (expense): The effective tax rate for 2014 was slightly lower than 2013 due primarily to an increase in an estimated flow-through tax adjustment.

Regulatory Matters — Utilities Group

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

| | Type of Service | Date Requested | Effective Date | Revenue Amount Requested | Revenue Amount Approved |
|----------------------------------|-----------------|----------------|----------------|--------------------------|-------------------------|
| Cheyenne Light ^(a) | Electric/Gas | 12/2013 | 10/2014 | \$14.1 | \$9.2 |
| Black Hills Power ^(b) | Electric | 1/2014 | pending | \$2.8 | pending |
| Black Hills Power ^(c) | Electric | 3/2014 | pending | \$14.6 | pending |
| Iowa Gas ^(d) | Gas | 2/2014 | 4/2014 | \$0.5 | \$0.5 |
| Kansas Gas ^(e) | Gas | 4/2014 | pending | \$7.3 | pending |
| Colorado Electric ^(f) | Electric | 4/2014 | pending | \$7.2 | pending |

On July 31, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Cheyenne Light of \$8.4 million and \$0.8 million for annual electric and natural gas revenue, respectively, effective October 1, (a)2014. The settlement also included a return on equity of 9.9%, and a capital structure of 54% equity and 46% debt. The WPSC's decision provides Cheyenne Light a return on its investment in Cheyenne Prairie and associated infrastructure, and provides recovery of its share of operating expenses for the natural gas-fired facility.

On January 17, 2014, Black Hills Power filed a rate request with the WPSC for an annual revenue increase of \$2.8 million to recover investments made in electric infrastructure, primarily for Cheyenne Prairie. The filing seeks a (b)return on equity of 10.25% and a capital structure of approximately 53.3% equity and 46.7% debt. Black Hills Power is seeking to implement the new rates on October 1, 2014, to coincide with Cheyenne Prairie's expected in-service date.

(c)On March 31, 2014, Black Hills Power filed a rate request with the SDPUC to increase annual revenue by \$14.6 million to recover operating expenses and infrastructure investments, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25%, and a capital structure of approximately 53.3% equity and 46.7% debt. Black

Hills Power is seeking to implement the new rates on October 1, 2014, to coincide with Cheyenne Prairie's expected in-service date.

(d) On April 15, 2014, the IUB approved a capital investment recovery surcharge increase of \$0.5 million.

On April 29, 2014, Kansas Gas filed a rate request with the KCC to increase annual revenue by \$7.3 million (e) primarily to recover infrastructure and increased operating costs. The filing seeks a return on equity of 10.6%, and a capital structure of approximately 50.3% equity and 49.7% debt.

On April 30, 2014, Colorado Electric filed a rate request with the CPUC for an annual revenue increase of \$8.0 million to recover operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm. Colorado Electric seeks approval of a new rider pursuant to the Clean Air-Clean Jobs Act Adjustment, to (f) recover a return on the expenditures associated with the construction of a \$65 million natural gas-fired combustion turbine unit, previously approved by the CPUC to replace the W.N. Clark retirement. The filing seeks a return on equity of 10.3% and a capital structure of approximately 50.5% equity and 49.5% debt. A subsequent filing on June 27, 2014 reduced our request to \$7.2 million to reflect updated cost information.

Non-regulated Energy Group

We report three segments within our Non-regulated Energy Group: Power Generation, Coal Mining and Oil and Gas.

Power Generation

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|-------------------------------|-----------------------------|----------|----------|---------------------------|----------|----------|
| | 2014 | 2013 | Variance | 2014 | 2013 | Variance |
| | (in thousands) | | | | | |
| Revenue | \$21,980 | \$20,125 | \$1,855 | \$44,328 | \$40,485 | \$3,843 |
| Operations and maintenance | 8,733 | 8,161 | 572 | 16,410 | 15,952 | 458 |
| Depreciation and amortization | 1,154 | 1,313 | (159) |)2,363 | 2,539 | (176) |
| Total operating expense | 9,887 | 9,474 | 413 | 18,773 | 18,491 | 282 |
| Operating income | 12,093 | 10,651 | 1,442 | 25,555 | 21,994 | 3,561 |
| Interest expense, net | (934) |)(2,706) |)1,772 | (1,862) |)(5,380) |)3,518 |
| Other (expense) income, net | 2 | (4) |)6 | (7) |)(3) |)(4) |
| Income tax (expense) benefit | (3,967) |)(2,910) |)(1,057) |)(8,419) |)(5,936) |)(2,483) |
| Net income (loss) | \$7,194 | \$5,031 | \$2,163 | \$15,267 | \$10,675 | \$4,592 |

The generating facility located in Pueblo, Colorado is accounted for as a capital lease under GAAP; as such, revenue and depreciation expense are impacted by the accounting for this lease. Under the lease, the original cost of the facility is recorded at Colorado Electric and is being depreciated by Colorado Electric for segment reporting purposes.

The following table summarizes MWh for our Power Generation segment:

| Quantities Sold, Generated and Purchased (MWh) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|-----------------------------|----------------|---------------------------|----------------|
| | 2014 | 2013 | 2014 | 2013 |
| (in thousands) | | | | |
| Sold | | | | |
| Black Hills Colorado IPP | 273,200 | 186,921 | 559,156 | 421,117 |
| Black Hills Wyoming | 138,377 | 134,896 | 278,985 | 277,002 |
| Total Sold | 411,577 | 321,817 | 838,141 | 698,119 |
| Generated | | | | |
| Black Hills Colorado IPP | 273,200 | 186,921 | 559,156 | 421,117 |
| Black Hills Wyoming | 141,458 | 135,056 | 282,136 | 279,245 |
| Total Generated | 414,658 | 321,977 | 841,292 | 700,362 |
| Purchased | | | | |
| Black Hills Colorado IPP | — | — | — | — |
| Black Hills Wyoming | 16 | 721 | 1,005 | 721 |
| Total Purchased | 16 | 721 | 1,005 | 721 |

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

| Contracted power plant fleet availability: | Three Months Ended June 30, | | Six Months Ended June 30, | | |
|--|-----------------------------|--------------|---------------------------|--------------|----------|
| | 2014 | 2013 | 2014 | 2013 | |
| Coal-fired plant | 98.7 | %94.0 | % 99.0 | %97.0 | % |
| Natural gas-fired plants | 99.2 | %99.2 | % 98.5 | %98.9 | % |
| Total availability | 99.1 | %98.0 | % 98.6 | %98.5 | % |

Results of Operations for Power Generation for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net income for the Power Generation segment was \$7.2 million for the three months ended June 30, 2014, compared to Net income of \$5.0 million for the same period in 2013 as a result of:

Revenue increased primarily due to an increase in megawatt hours delivered at higher prices and an increase in megawatt hours sold and pricing for off-system sales at Black Hills Wyoming.

Operations and maintenance increased primarily due to repairs and maintenance at Colorado IPP.

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

Interest expense, net decreased primarily due to refinancing higher cost project debt and settling associated interest rate swaps in the fourth quarter of 2013.

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

Income tax (expense) benefit: The effective tax rate is comparable to the same period in the prior year.

Results of Operations for Power Generation for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net income for the Power Generation segment was \$15.3 million for the six months ended June 30, 2014, compared to Net income of \$10.7 million for the same period in 2013 as a result of:

Revenue increased primarily due to an increase in megawatts delivered at higher prices, an increase in fired hours and an increase in off-system megawatt hour sales and pricing at Black Hills Wyoming.

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

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

Interest expense, net decreased primarily due to refinancing higher cost project debt and settling associated interest rate swaps in the fourth quarter of 2013.

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

Income tax (expense) benefit: The effective tax rate is comparable to the same period in the prior year.

Coal Mining

| | Three Months Ended June 30, 2014 | | | Six Months Ended June 30, 2014 | | |
|--|-------------------------------------|----------|-------|-----------------------------------|----------|---------|
| | 2013 | Variance | 2013 | Variance | | |
| | (in thousands) | | | | | |
| Revenue | \$14,651 | \$14,318 | \$333 | \$30,149 | \$27,901 | \$2,248 |
| Operations and maintenance | 10,023 | 9,251 | 772 | 20,154 | 19,402 | 752 |
| Depreciation, depletion and amortization | 2,570 | 2,964 | (394) | 5,260 | 5,829 | (569) |
| Total operating expenses | 12,593 | 12,215 | 378 | 25,414 | 25,231 | 183 |
| Operating income (loss) | 2,058 | 2,103 | (45) | 4,735 | 2,670 | 2,065 |
| Interest (expense) income, net | (113) | (179) | 66 | (216) | (310) | 94 |
| Other income, net | 589 | 581 | 8 | 1,192 | 1,194 | (2) |
| Income tax benefit (expense) | (518) | (532) | 14 | (1,231) | (516) | (715) |
| Net income (loss) | \$2,016 | \$1,973 | \$43 | \$4,480 | \$3,038 | \$1,442 |

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---------------------------------|-----------------------------|---------|---------------------------|---------|
| | 2014 | 2013 | 2014 | 2013 |
| Tons of coal sold | 1,063 | 1,079 | 2,150 | 2,132 |
| Cubic yards of overburden moved | 1,010 | 930 | 1,920 | 1,989 |
| Revenue per ton | \$13.79 | \$13.27 | \$14.03 | \$13.09 |

Results of Operations for Coal Mining for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net income for the Coal Mining segment was \$2.0 million for the three months ended June 30, 2014, compared to Net income of \$2.0 million for the same period in 2013 as a result of:

Revenue increased primarily due to a 4% increase in price per ton sold, partially offset by a 1% decrease in tons sold. Approximately 50% of our coal production is sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operations and maintenance increased primarily due to materials and outside services for major maintenance projects.

Depreciation, depletion and amortization decreased primarily due to lower depreciation on mine assets and mine reclamation asset retirement costs.

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

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

Income tax benefit (expense): The effective tax rate is comparable to the same period in the prior year.

Results of Operations for Coal Mining for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net income for the Coal Mining segment was \$4.5 million for the six months ended June 30, 2014, compared to Net income of \$3.0 million for the same period in 2013 as a result of:

Revenue increased primarily due to a 7% increase in price per ton sold and a 1% increase in tons sold. Approximately 50% of our coal production is sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operations and maintenance increased primarily due to materials and outside services on major maintenance projects, partially offset by lower overburden removal costs, lower employee costs, and a favorable coal tax adjustment of \$0.7 million.

Depreciation, depletion and amortization decreased primarily due to lower depreciation on mine assets and mine reclamation asset retirement costs.

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

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

Income tax benefit (expense): The increase in the effective tax rate in 2014 is due primarily to the reduced impact of the tax benefit of percentage depletion.

Oil and Gas

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|--|-----------------------------|----------|----------|---------------------------|----------|----------|
| | 2014 | 2013 | Variance | 2014 | 2013 | Variance |
| | (in thousands) | | | | | |
| Revenue | \$15,148 | \$11,814 | \$3,334 | \$29,998 | \$27,158 | \$2,840 |
| Operations and maintenance | 10,239 | 9,995 | 244 | 21,378 | 20,250 | 1,128 |
| Depreciation, depletion and amortization | 7,290 | 5,214 | 2,076 | 13,923 | 10,581 | 3,342 |
| Total operating expenses | 17,529 | 15,209 | 2,320 | 35,301 | 30,831 | 4,470 |
| Operating income (loss) | (2,381) |)(3,395) |)1,014 | (5,303) |)(3,673) |)(1,630) |
| Interest income (expense), net | (442) |)(54) |)(388) |)(897) |)25 | (922) |
| Other income (expense), net | 49 | 81 | (32) |)87 | 4 | 83 |
| Income tax benefit (expense) | 1,114 | 1,404 | (290) |)2,431 | 1,627 | 804 |
| Net income (loss) | \$(1,660) |)(1,964) |)\$304 | \$(3,682) |)(2,017) |)(1,665) |

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|-------------------------|-----------------------------|-----------|---------------------------|-----------|
| | 2014 | 2013 | 2014 | 2013 |
| Production: | | | | |
| Bbls of oil sold | 92,228 | 65,304 | 166,490 | 162,107 |
| Mcf of natural gas sold | 1,840,826 | 1,784,389 | 3,600,790 | 3,517,339 |
| Gallons of NGL sold | 1,764,111 | 895,720 | 2,899,832 | 1,841,534 |
| Mcf equivalent sales | 2,646,210 | 2,304,173 | 5,013,992 | 4,753,057 |

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|-----------------------------|---------|---------------------------|---------|
| | 2014 | 2013 | 2014 | 2013 |
| Average price received: ^(a) | | | | |
| Oil/Bbl | \$78.18 | \$95.15 | \$84.56 | \$91.71 |
| Gas/Mcf | \$3.17 | \$2.35 | \$3.25 | \$2.63 |
| NGL/gallon | \$0.80 | \$0.73 | \$0.95 | \$0.84 |
| Depletion expense/Mcfe | \$2.36 | \$1.82 | \$2.31 | \$1.80 |

(a) Net of hedge settlement gains and losses.

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

| Producing Basin | Three Months Ended June 30, 2014 | | | | Three Months Ended June 30, 2013 | | | |
|------------------------|----------------------------------|--|---------------------|--------|----------------------------------|--|---------------------|--------|
| | LOE | Gathering, Compression and Processing | Production Taxes | Total | LOE | Gathering, Compression and Processing | Production Taxes | Total |
| San Juan | \$1.39 | \$0.46 | \$0.59 | \$2.44 | \$1.39 | \$0.40 | \$0.52 | \$2.31 |
| Piceance | 0.26 | 0.23 | 0.35 | 0.84 | 0.80 | 0.52 | 0.27 | 1.59 |
| Powder River | 1.55 | — | 1.15 | 2.70 | 2.00 | — | 1.23 | 3.23 |
| Williston | 1.31 | — | 1.41 | 2.72 | 1.43 | — | 2.52 | 3.95 |
| All other properties | 1.30 | — | 0.77 | 2.07 | 0.65 | — | (0.48) | 0.17 |
| Total weighted average | \$1.08 | \$0.23 | \$0.72 | \$2.03 | \$1.32 | \$0.27 | \$0.55 | \$2.14 |

| Producing Basin | Six Months Ended June 30, 2014 | | | | Six Months Ended June 30, 2013 | | | |
|------------------------|--------------------------------|--|---------------------|--------|--------------------------------|--|---------------------|--------|
| | LOE | Gathering, Compression and Processing | Production Taxes | Total | LOE | Gathering, Compression and Processing | Production Taxes | Total |
| San Juan | \$1.46 | \$0.45 | \$0.61 | \$2.52 | \$1.34 | \$0.37 | \$0.47 | \$2.18 |
| Piceance | 0.11 | 0.23 | 0.45 | 0.79 | 0.73 | 0.58 | 0.30 | 1.61 |
| Powder River | 1.90 | — | 1.23 | 3.13 | 1.62 | — | 1.24 | 2.86 |
| Williston | 1.08 | — | 1.59 | 2.67 | 0.94 | — | 1.34 | 2.28 |
| All other properties | 1.47 | — | 0.36 | 1.83 | 0.67 | — | (0.08) | 0.59 |
| Total weighted average | \$1.13 | \$0.23 | \$0.73 | \$2.09 | \$1.19 | \$0.25 | \$0.60 | \$2.04 |

Results of Operations for Oil and Gas for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net loss for the Oil and Gas segment was \$1.7 million for the three months ended June 30, 2014, compared to Net loss of \$2.0 million for the same period in 2013 as a result of:

Revenue increased primarily due to a 15% increase in volumes sold driven by production from two new Piceance Mancos Shale wells and an increase in non-operated Bakken crude oil volumes sold, and a 35% increase in the average hedged price received for natural gas sold. These increases were partially offset by an 18% decrease in the average price received for crude oil sold.

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

Depreciation, depletion and amortization increased primarily due to a higher depletion rate, applied to greater production.

Interest income (expense), net was comparable to prior year.

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

Income tax (expense) benefit: The effective tax rate is higher in 2014 primarily due to the research and development tax credit not being extended to 2014.

Results of Operations for Oil and Gas for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net loss for the Oil and Gas segment was \$3.7 million for the six months ended June 30, 2014, compared to Net loss of \$2.0 million for the same period in 2013 as a result of:

Revenue increased primarily due to a 5% increase in volumes sold driven by increased gallons of NGL sales from production on the two new Mancos Shale wells, and a 24% increase in the average hedged price received for natural gas sold, partially offset by an 8% decrease in the average price received for crude oil sold.

Operations and maintenance increased primarily due to higher non-operated well costs, higher production taxes and ad valorem taxes on higher natural gas revenue.

Depreciation, depletion and amortization increased primarily due to a higher depletion rate, applied to greater production.

Interest income (expense), net increased primarily due to interest received on third-party non-operated well revenue in the prior year that offset interest expense.

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

Income tax (expense) benefit: The effective tax rate is higher in 2014 primarily due to the research and development tax credit not being extended to 2014. The prior year reflected the entire year of the 2012 research and development tax credit due to retroactive reinstatement of the credit in January 2013 by the U.S. Congress.

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net loss for Corporate was \$1.2 million for the three months ended June 30, 2014, compared to Net income of \$11.7 million for the three months ended June 30, 2013 as a result of:

The settlement of the de-designated interest rate swaps in the fourth quarter of 2013, resulted in no activity for the three months ended June 30, 2014, compared to the recognition of an unrealized, non-cash mark-to-market gain of \$18.8 million during the three months ended June 30, 2013.

The income for the three months ended June 30, 2014 included lower interest expense as compared to the three months ended June 30, 2013, as a result of lower interest rate debt from refinancing activities in fourth quarter 2013 and the settlement of the de-designated interest rate swaps.

Results of Operations for Corporate activities for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net loss for Corporate was \$0.8 million for the six months ended June 30, 2014, compared to Net income of \$17.4 million for the six months ended June 30, 2013 as a result of:

The settlement of the de-designated interest rate swaps in the fourth quarter of 2013, resulted in no activity for the six months ended June 30, 2014, compared to the recognition of an unrealized, non-cash mark-to-market gain of \$26.2 million during the six months ended June 30, 2013.

The income for the six months ended June 30, 2014 included lower interest expense as compared to the six months ended June 30, 2013, as a result of lower interest rate debt from refinancing activities in fourth quarter 2013 and the settlement of the de-designated interest rate swaps.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2013 Annual Report on Form 10-K filed with the SEC. For more information on our critical accounting policies, see Part II, Item 7 of our 2013 Annual Report on Form 10-K.

Liquidity and Capital Resources

OVERVIEW

BHC and its subsidiaries require significant amounts of cash to support and grow our business. Our predominant source of cash is supplied by our operations and supplemented with corporate borrowings. This cash is used for, among other things, working capital, capital expenditures, dividends, pension funding, investments in or acquisitions of assets and businesses, payment of debt obligations and redemption of outstanding debt and equity securities when required or financially appropriate.

The most significant items impacting cash are our capital expenditures, the purchase of natural gas for our Utilities Group and our Power Generation segment, and the payment of dividends to our shareholders. Generally, we experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, debt maturities, anticipated dividends, and anticipated capital expenditures discussed in this section.

Significant Factors Affecting Liquidity

Although we believe we have sufficient resources to fund our cash requirements, there are many factors with the potential to influence our cash flow position, including seasonality, commodity prices, significant capital projects, requirements imposed by state and federal agencies, and economic market conditions. We have implemented risk mitigation programs, where possible, to stabilize cash flow; however, the potential for unforeseen events affecting cash needs will continue to exist.

Cash Flow Activities

The following table summarizes our cash flows for the six months ended June 30, 2014 and 2013 (in thousands):

| Cash provided by (used in): | 2014 | 2013 | Increase (Decrease) |
|-----------------------------|--------------|--------------|------------------------|
| Operating activities | \$173,835 | \$197,385 | \$(23,550) |
| Investing activities | \$(180,296) | \$(145,224) | \$(35,072) |
| Financing activities | \$13,317 | \$(36,990) |)\$50,307 |

Year-to-Date 2014 Compared to Year-to-Date 2013

Operating Activities

Net cash provided by operating activities was \$24 million lower for the six months ended June 30, 2014, than for the same period in 2013 primarily attributable to:

• Cash earnings (net income plus non-cash adjustments) were \$4.1 million higher for the six months ended June 30, 2014 than for the same period in the prior year.

• Net outflows from operating assets and liabilities were \$24 million for the six months ended June 30, 2014, compared to net cash outflows of \$11 million in the same period in the prior year. Changes are primarily due to:

- Increased working capital requirements resulting from higher natural gas volumes sold during our peak winter heating season months driven by cold weather and higher natural gas prices creating an increase in fuel cost adjustments recorded in regulatory assets in our Utility Group; and

• Receipt in 2013 of approximately \$8.4 million from a government grant relating to the Busch Ranch wind project.

Investing Activities

Net cash used in investing activities was \$180 million for the six months ended June 30, 2014, compared to net cash used in investing activities of \$145 million for the same period in 2013 for a variance of \$35 million. The variance was primarily driven by:

• Capital expenditures of approximately \$177 million for the six months ended June 30, 2014, compared to \$147 million for the six months ended June 30, 2013. The increase is related primarily to the construction of Cheyenne Prairie at our Electric Utilities segment.

Financing Activities

Net cash provided by financing activities for the six months ended June 30, 2014, was \$13.3 million, compared to net cash used in financing activities for the same period in 2013 of \$37 million for a variance of \$50 million. The variance was primarily driven by:

Net short-term borrowings under the revolving credit facility for the six months ended June 30, 2014 were used primarily to fund additional working capital requirements due to colder weather during the peak winter heating season and the increase in overall capital expenditures. The prior period reflected the refinancing of the \$275 million term loan, proceeds of which, replaced a short term loan of \$150 million, a short term loan of \$100 million, and \$25 million used to pay off short-term borrowings under the Revolving Credit Facility.

Dividends

Dividends paid on our common stock totaled \$34.8 million for the six months ended June 30, 2014, or \$0.78 per share. On July 30, 2014, our board of directors declared a quarterly dividend of \$0.39 per share payable September 1, 2014, which is equivalent to an annual dividend rate of \$1.56 per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our Revolving Credit Facility and our future business prospects.

Debt

Financing Transactions and Short-Term Liquidity

Our principal sources to meet day-to-day operating cash requirements are cash from operations and our corporate Revolving Credit Facility.

Revolving Credit Facility

On May 29, 2014, we amended our \$500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to \$750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from S&P and Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.125%, 1.125% and 1.125%, respectively, from May 29, 2014 through June 30, 2014; a reduction of 0.250% for each method of borrowing. A commitment fee is charged on the unused amount of the Revolving Credit Facility and is 0.175% based on our credit rating, a reduction of 0.025% compared to the prior arrangement.

Our Revolving Credit Facility had the following borrowings, outstanding letters of credit and available capacity (in millions):

| Credit Facility | Expiration | Current Capacity | Borrowings at June 30, 2014 | Letters of Credit at June 30, 2014 | Available Capacity at June 30, 2014 |
|---------------------------|--------------|------------------|-----------------------------|------------------------------------|-------------------------------------|
| Revolving Credit Facility | May 29, 2019 | \$ 500 | \$ 133 | \$ 20 | \$ 347 |

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintaining a certain recourse leverage ratio. Under the Revolving Credit Facility, our recourse leverage ratio is calculated by dividing the sum of our recourse debt, letters of credit and certain guarantees issued, by total capital, which includes recourse indebtedness plus our net worth. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of June 30, 2014.

The Revolving Credit Facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after, paying a dividend. Although these contractual restrictions exist, we do not anticipate triggering any default measures or restrictions.

Hedges and Derivatives

Interest Rate Swaps

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. We have \$75 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of approximately 2.5 years. These swaps have been designated as cash flow hedges for the Revolving Credit Facility, and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of \$7.7 million at June 30, 2014.

Financing Activities

On June 30, 2014, Black Hills Power and Cheyenne Light entered into Bond Purchase Agreements, to authorize the sale of \$160 million of first mortgage bonds in a private placement to finance Cheyenne Prairie. Black Hills Power will issue \$85 million of 4.43% first mortgage bonds due October 20, 2044. Cheyenne Light will issue \$75 million of 4.53% first mortgage bonds due October 20, 2044. The closing date for the sale of the first mortgage bonds for both utilities is anticipated to be October 1, 2014, subject to satisfaction of customary closing conditions.

On November 19, 2013, we entered into a \$525 million, 4.25% senior unsecured note expiring on November 30, 2023. The proceeds of this debt were used to:

Redeem our \$250 million senior unsecured 9.0% notes originally due on May 15, 2014. This repayment occurred on December 19, 2013, for approximately \$261 million which included a make-whole provision of approximately \$8.5 million and accrued interest.

Repay our variable interest rate Black Hills Wyoming project financing with a remaining balance of \$87 million originally due on December 9, 2016, and settle the interest rate swaps designated to this project financing of \$8.5 million.

Settle the \$250 million notional de-designated interest rate swaps for approximately \$64 million.

Pay down \$55 million of the Revolving Credit Facility.

Remainder was used for general corporate purposes.

On June 21, 2013, we entered into a new two-year \$275 million term loan expiring on June 19, 2015. The proceeds from this new term loan repaid the \$150 million term loan due on June 24, 2013, the \$100 million long-term corporate term loan due on September 30, 2013, and \$25 million in short-term borrowing under our Revolving Credit Facility. At June 30, 2014, the cost of borrowing under this new term loan was 1.3125% (LIBOR plus a margin of 1.125%).

Future Financing Plans

We anticipate the following financing activities:

Closing on the delayed-draw private placement bonds Black Hills Power and Cheyenne Light executed on June 30, 2014 to finance Cheyenne Prairie. It's anticipated that Black Hills Power and Cheyenne Light will execute the draw of \$85 million and \$75 million, respectively, on October 1, 2014; and

Evaluate options for the \$275 million term loan expiring on June 19, 2015.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Colorado, Iowa, Kansas and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its subsidiaries can extend credit to the Company except in ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. As of June 30, 2014, the restricted net assets at our Electric Utilities and Gas Utilities were approximately \$141 million. Our credit facilities and other debt obligations contain 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 only financial covenant under our Revolving Credit Facility is a recourse leverage ratio not to exceed 0.65 to 1.00. Additionally, covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of June 30, 2014, we were in compliance with this covenant.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2013 Annual Report on Form 10-K filed with the SEC.

Credit Ratings

Financing for operational needs and capital expenditure requirements not satisfied by operating cash flows depends upon the cost and availability of external funds through both short and long-term financing. The inability to raise capital on favorable terms could negatively affect our ability to maintain or expand our businesses. Access to funds is dependent upon factors such as general economic and capital market conditions, regulatory authorizations and policies, our credit ratings, cash flows from routine operations and the credit ratings of counterparties. After assessing the current operating performance, liquidity and our credit ratings, management believes that we will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. Credit ratings are prepared by third party rating agencies and are not recommendations to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The following table represents the credit ratings and outlook of BHC at June 30, 2014:

| Rating Agency | Senior Unsecured Rating | Outlook |
|------------------------|----------------------------|---------|
| S&P | BBB | Stable |
| Moody's ^(a) | Baa1 | Stable |
| Fitch ^(b) | BBB+ | Stable |

(a) On January 30, 2014, Moody's upgraded the BHC credit rating to Baa1 with a Stable outlook.

(b) On June 13, 2014, Fitch upgraded the BHC credit rating to BBB+ with a Stable outlook.

The following table represents the credit ratings of Black Hills Power's Senior Secured Mortgage Bonds at June 30, 2014:

| | |
|---------------|-----------------------|
| Rating Agency | Senior Secured Rating |
| S&P | A- |
| Moody's * | A1 |
| Fitch ** | A |

* On January 30, 2014, Moody's upgraded the BHP credit rating to A1 with a Stable outlook.

** On June 13, 2014, Fitch upgraded the BHP credit rating to A with a Stable outlook.

Capital Requirements

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

| | Expenditures for the Six Months Ended June 30, 2014 ^(a) | Total 2014 Planned Expenditures ^(b) | Total 2015 Planned Expenditures | Total 2016 Planned Expenditures |
|-----------------------|--|--|---------------------------------------|---------------------------------------|
| Utilities: | | | | |
| Electric Utilities | \$96,249 | \$250,700 | \$189,300 | \$160,500 |
| Gas Utilities | 22,176 | 63,000 | 62,000 | 47,600 |
| Non-regulated Energy: | | | | |
| Power Generation | 48 | 2,500 | 5,200 | 3,200 |
| Coal Mining | 2,755 | 6,600 | 6,200 | 7,300 |
| Oil and Gas | 27,859 | 117,800 | 122,700 | 122,200 |
| Corporate | 9,013 | 8,700 | 5,900 | 6,100 |
| | \$158,100 | \$449,300 | \$391,300 | \$346,900 |

(a) Expenditures for the six months ended June 30, 2014 include the impact of accruals for property, plant and equipment.

(b) Includes actual expenditures for the six months ended June 30, 2014.

We continue to evaluate potential future acquisitions and other growth opportunities that are dependent upon the availability of economic opportunities; as a result, capital expenditures may vary significantly from the estimates identified above.

Contractual Obligations

Except as noted below, there have been no significant changes in the contractual obligations from those previously disclosed in Note 18 of our Notes to the Consolidated Financial Statements in our 2013 Annual Report on Form 10-K.

Natural Gas Delivery Agreement

In 2012, we entered into a ten-year gas gathering and processing contract for natural gas production from our properties in the Piceance Basin in Colorado, under which we pay a gathering fee per Mcf. The contract requires us to deliver a minimum of 20,000 Mcf per day. This agreement became effective in first quarter of 2014 upon completion of the processing infrastructure capable of handling the committed volumes. We believe that our reserves dedicated to the gathering system, and the projected volumes are adequate to materially satisfy our delivery commitments under this agreement.

Construction Commitments

Construction of Cheyenne Prairie, a 132 MW natural gas-fired electric generating facility jointly owned by Cheyenne Light and Black Hills Power is expected to cost approximately \$222 million. Construction is expected to be completed by September 30, 2014. As of June 30, 2014, contracts for equipment purchases and for construction were 100% and 98% committed, respectively.

58

Bond Purchase Agreements

On June 30, 2014, Black Hills Power and Cheyenne Light entered into agreements to issue \$160 million of first mortgage bonds to finance Cheyenne Prairie. Black Hills Power will issue \$85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light will issue \$75 million of 4.53% coupon first mortgage bonds due October 20, 2044. The closing date for the sale of the first mortgage bonds for both utilities is anticipated October 1, 2014.

Guarantees

Except as noted below, there have been no significant changes to guarantees from those previously disclosed in Note 19 of the Notes to the Consolidated Financial Statements in our 2013 Annual Report on Form 10-K.

During the second quarter, guarantees of payment obligations arising from commodity transactions of BHUH for natural gas supply were reduced by \$70 million and no longer exist, primarily due to improvement of the corporate credit rating, as well as the conversion of certain guarantees to letters of credit.

New Accounting Pronouncements

Other than the pronouncements reported in our 2013 Annual Report on Form 10-K filed with the SEC and those discussed in Note 1 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial position, results of operations, or cash flows.

FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking statements as defined by the SEC. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words “anticipates,” “estimates,” “expects,” “intends,” “plans,” “predicts” and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 2 - Management’s Discussion & Analysis of Financial Condition and Results of Operations.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management’s examination of historical operating trends, data contained in the Company’s records and other data available from third parties. Nonetheless, the Company’s expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement was made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement was made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company,

are expressly qualified by the risk factors and cautionary statements described in our 2013 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2013 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q and other reports that we file with the SEC from time to time.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

Our utility customers are exposed to natural gas price volatility; therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. The fair value of our Utilities Group's derivative contracts is summarized below (in thousands) as of:

| | June 30, 2014 | December 31, 2013 | June 30, 2013 |
|--|---------------|-------------------|---------------|
| Net derivative (liabilities) assets | \$(1,647 |) \$(6,071 |) \$(7,203 |
| Cash collateral offset in Derivatives | 3,384 | 6,733 | 7,203 |
| Cash Collateral included in Other current assets | 2,767 | 3,390 | 2,938 |
| Net receivable (liability) position | \$4,504 | \$4,052 | \$2,938 |

Oil and Gas Activities

We have entered into agreements to hedge a portion of our estimated 2014, 2015 and 2016 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at June 30, 2014, were as follows:

Natural Gas

| | March 31, | June 30, | September 30, | December 31, | Total Year |
|----------------------------------|-----------|-----------|---------------|--------------|------------|
| 2014 | | | | | |
| Swaps - MMBtu | — | — | 1,335,000 | 1,305,000 | 2,640,000 |
| Weighted Average Price per MMBtu | \$— | \$— | \$4.03 | \$4.04 | \$4.03 |
| 2015 | | | | | |
| Swaps - MMBtu | 1,217,500 | 1,180,000 | 955,000 | 1,000,000 | 4,352,500 |
| Weighted Average Price per MMBtu | \$4.24 | \$4.03 | \$4.00 | \$4.04 | \$4.08 |
| 2016 | | | | | |
| Swaps - MMBtu | 587,500 | 572,500 | 567,500 | 545,000 | 2,272,500 |
| Weighted Average Price per MMBtu | \$3.91 | \$3.98 | \$4.08 | \$3.90 | \$3.97 |

Crude Oil

| | March 31, | June 30, | September 30, | December 31, | Total Year |
|--------------------------------|-----------|----------|---------------|--------------|------------|
| 2014 | | | | | |
| Swaps - Bbls | — | — | 57,000 | 57,000 | 114,000 |
| Weighted Average Price per Bbl | \$— | \$— | \$90.55 | \$90.66 | \$90.60 |
| 2015 | | | | | |
| Swaps - Bbls | 55,500 | 51,000 | 42,000 | 36,000 | 184,500 |
| Weighted Average Price per Bbl | \$89.98 | \$87.84 | \$88.18 | \$87.92 | \$88.48 |
| 2016 | | | | | |
| Swaps - Bbls | 33,000 | 33,000 | 30,000 | 30,000 | 126,000 |
| Weighted Average Price per Bbl | \$83.45 | \$83.45 | \$83.33 | \$83.33 | \$83.39 |

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. Further details of the swap agreements are set forth in Note 8 of the Notes to Consolidated Financial Statements in our 2013 Annual Report on Form 10-K and in Note 8 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

| | June 30, 2014 | December 31, 2013 | June 30, 2013 | |
|--|---|---|---|--|
| | Designated Interest Rate Swaps ^(a) | Designated Interest Rate Swaps ^(a) | Designated Interest Rate Swaps ^(b) | De-designated Interest Rate Swaps ^(c) |
| Notional | \$75,000 | \$75,000 | \$150,000 | \$250,000 |
| Weighted average fixed interest rate | 4.97 | % 4.97 | % 5.04 | % 5.67 |
| Maximum terms in years | 2.5 | 3.0 | 3.5 | 0.5 |
| Derivative liabilities, current | \$3,480 | \$3,474 | \$6,965 | \$61,899 |
| Derivative liabilities, non-current | \$4,251 | \$5,614 | \$12,384 | \$— |
| Pre-tax accumulated other comprehensive income (loss) | \$(7,731) | \$(9,088) | \$(19,349) | \$— |

(a) These swaps are designated to borrowings on our Revolving Credit Facility, and are priced using three-month LIBOR, matching the floating portion of the related debt.

At June 30, 2013, \$75 million of these interest rate swaps were designated to borrowings on our Revolving Credit Facility and \$75 million were designated to borrowings on our project financing debt at Black Hills Wyoming.

(b) These swaps are priced using three-month LIBOR, matching the floating portion of the related swaps. The portion of the swaps that were designated to Black Hills Wyoming were settled during the fourth quarter of 2013 upon repayment of the Black Hills Wyoming project financing.

(c) These swaps were settled during the fourth quarter of 2013.

Based on June 30, 2014 market interest rates and balances related to our interest rate swaps, a loss of approximately \$3.5 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Estimated and actual realized gains or losses will change during future periods as market interest rates change.

ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) as of June 30, 2014. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

During the quarter ended June 30, 2014, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 18 in Item 8 of our 2013 Annual Report on Form 10-K and Note 14 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 14 is incorporated by reference into this item.

ITEM 1A. Risk Factors

Except as noted below, there are no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2013 Annual Report on Form 10-K.

ENVIRONMENTAL RISKS

Federal and state laws concerning greenhouse gas regulations and air emissions may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain.

We own and operate regulated and non-regulated fossil-fuel generating plants in South Dakota, Wyoming, and Colorado. Recent developments under federal and state laws and regulations governing air emissions from fossil-fuel generating plants will likely result in more stringent emission limitations, which could have a material impact on our costs of operations. In addition to the environmental matters identified in Item 1A of our Annual Report on Form 10-K under the caption “Environmental Matters”, the following recently proposed regulations could negatively impact our operations.

On June 2, 2014, the EPA proposed the Clean Power Plan to cut carbon emissions from existing electric generating units. The design of the Clean Power Plan is to decrease existing coal-fired generation, and increase the utilization of existing gas generation, increase renewable energy, and demand side management. This rule could have a significant impact on our coal and natural gas generating fleet. The rule calls for states to develop plans to meet their assigned emission rate targets by 2030. The rule also allows states to formulate a regional approach whereby they would join with other states and be assigned a new single target for the group. We are currently evaluating this proposal, but cannot predict the impact on operations as this rule is expected to be final in June 2015, and state plans are expected to be due at the earliest in June 2016, with extensions possible to 2017 and 2018. We expect any impact to us to be mitigated through the recent Osage, Ben French, Neil Simpson I and W.N. Clark plant closures.

The Clean Power Plan could have a significant impact on our WRDC coal mine. Coal competes with other energy sources, such as natural gas, wind, solar and hydropower. If the Clean Power Plan Rule regulations were to have an adverse effect on coal as a domestic energy source, this rule could have a significant impact on our coal mining operations.

New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, and the closure of certain generating facilities. To the extent our regulated fossil-fuel generating plants are included in rate base we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the

power generated by those non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.

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

There were no unregistered securities sold during the six months ended June 30, 2014.

ITEM 4. Mine Safety Disclosures

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included in Exhibit 95 of this Quarterly Report on Form 10-Q.

ITEM 5. Other Information

None.

ITEM 6. Exhibits

| Exhibit Number | Description |
|----------------|--|
| Exhibit 3.1* | Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 10-K for 2004). |
| Exhibit 3.2* | Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 3, 2010). |
| Exhibit 4.1* | Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013). |
| Exhibit 4.2* | Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). |
| Exhibit 4.3* | Form of Stock Certificate for Common Stock, Par Value \$1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000). |

Exhibit 10.1* Credit Agreement dated May 29, 2014 among Black Hills Corporation, as Borrower, U.S. Bank, National Association, in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 30, 2014.)

Exhibit 10.2* Bond Purchase Agreement dated as of June 30, 2014 by and among Black Hills Power, Inc., New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York and United of Omaha Life Insurance Company (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 2, 2014.)

| | |
|---------------|--|
| Exhibit 10.3* | Bond Purchase Agreement dated as of June 30, 2014 by and among Cheyenne Light, Fuel and Power Company, New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York, Mutual of Omaha Insurance Company, United of Omaha Life Insurance Company and American Equity Investment Life Insurance Company (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 2, 2014.) |
| Exhibit 31.1 | Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002. |
| Exhibit 31.2 | Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002. |
| Exhibit 32.1 | Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002. |
| Exhibit 32.2 | Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002. |
| Exhibit 95 | Mine Safety and Health Administration Safety Data. |
| Exhibit 101 | Financial Statements for XBRL Format. |

*Previously filed as part of the filing indicated and incorporated by reference herein.

SIGNATURES

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

BLACK HILLS CORPORATION

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

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

Dated: August 6, 2014

INDEX TO EXHIBITS

| Exhibit Number | Description |
|----------------|--|
| Exhibit 3.1* | Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 10-K for 2004). |
| Exhibit 3.2* | Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 3, 2010). |
| Exhibit 4.1* | Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to the Registrant's Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrants' Form 8-K filed on November 18, 2013). |
| Exhibit 4.2* | Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). |
| Exhibit 4.3* | Form of Stock Certificate for Common Stock, Par Value \$1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000). |
| Exhibit 10.1* | Credit Agreement dated May 29, 2014 among Black Hills Corporation, as Borrower, U.S. Bank, National Association, in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 30, 2014.) |
| Exhibit 10.2* | Bond Purchase Agreement dated as of June 30, 2014 by and among Black Hills Power, Inc., New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York and United of Omaha Life Insurance Company (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 2, 2014.) |
| Exhibit 10.3* | Bond Purchase Agreement dated as of June 30, 2014 by and among Cheyenne Light, Fuel and Power Company, New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life |

Edgar Filing: BLACK HILLS CORP /SD/ - Form 10-Q

Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York, Mutual of Omaha Insurance Company, United of Omaha Life Insurance Company and American Equity Investment Life Insurance Company (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 2, 2014.)

- Exhibit 31.1 Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
- Exhibit 31.2 Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
- Exhibit 32.1 Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.

| | |
|--------------|--|
| Exhibit 32.2 | Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002. |
| Exhibit 95 | Mine Safety and Health Administration Safety Data. |
| Exhibit 101 | Financial Statements for XBRL Format. |

*Previously filed as part of the filing indicated and incorporated by reference herein.