BLACK HILLS CORP /SD/
Form 10-Q
August 04, 2017

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

Form 10-Q
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2017
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission File Number 001-31303
Black Hills Corporation
Incorporated in South Dakota IRS Identification Number 46-0458824
625 Ninth Street
Rapid City, South Dakota 57701
Registrant’s telephone number (605) 721-1700
Former name, former address, and former fiscal year if changed since last report
NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).
Yes x No o

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

| | |
|---|---|
| Large accelerated filer x | Accelerated filer o |
| Non-accelerated filer o | (Do not check if a smaller reporting company) |
| | Smaller reporting company o |
| | Emerging growth company o |

If an emerging growth company, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section

13(a) of the Exchange Act. o

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x

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

| Class | Outstanding at July 31, 2017 | |
|---|---|---|
| Common stock, $1.00 par value | 53,475,190 | shares |

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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) |
| APSC | Arkansas Public Service Commission |
| Arkansas Gas | Black Hills Energy Arkansas, Inc., a direct, wholly-owned subsidiary of Black Hills Gas Inc. |
| Stockton Storage | Arkansas Gas storage facility |
| ARMRP | At-Risk Meter Relocation Program |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update issued by the FASB |
| ATM | At-the-market equity offering program |
| Availability | The availability factor of a power plant is the percentage of the time that it is available to provide energy. |
| Bbl | Barrel |
| BHC | Black Hills Corporation; the Company |
| Black Hills Gas | Black Hills Gas, LLC, a subsidiary of Black Hills Gas Holdings, which was previously named SourceGas LLC |
| Black Hills Gas Holdings | Black Hills Gas Holdings, LLC, a subsidiary of Black Hills Utility Holdings, which was previously named SourceGas Holdings LLC |
| 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 our utility companies |
| Black Hills Energy Arkansas Gas | Includes the acquired SourceGas utility Black Hills Energy Arkansas, Inc. utility operations |
| Black Hills Energy Colorado Electric | Includes Colorado Electric’s utility operations |
| Black Hills Energy Colorado Gas | Includes Black Hills Energy Colorado Gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution’s Colorado gas operations and RMNG |
| Black Hills Energy Iowa Gas | Includes Black Hills Energy Iowa gas utility operations |
| Black Hills Energy Kansas Gas | Includes Black Hills Energy Kansas gas utility operations |
| Black Hills Energy Nebraska Gas | Includes Black Hills Energy Nebraska gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution’s Nebraska gas operations |
| Black Hills Energy South Dakota Electric | Includes Black Hills Power operations in South Dakota, Wyoming and Montana |
| Black Hills Energy Wyoming Electric | Includes Cheyenne Light’s electric utility operations |
| Black Hills Energy Wyoming Gas | Includes Cheyenne Light’s natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution’s Wyoming gas operations |
| Black Hills Gas Distribution | Black Hills Gas Distribution, LLC, a company acquired in the SourceGas Acquisition that conducts the gas distribution operations in Colorado, Nebraska and Wyoming. It was formerly named SourceGas Distribution LLC. |
| 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 (doing business as Black Hills Energy) |

| | |
|---|---|
| Black Hills Utility Holdings | Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy) |
| Black Hills Wyoming | Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation |
| Btu | British thermal unit |
| CAPP | Customer Appliance Protection Plan |

| | |
|---|---|
| Ceiling Test | Related to our Oil and Gas subsidiary, capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using prices and a discount rate defined by the SEC plus the lower of cost or market value of unevaluated properties. |
| Cheyenne Light | Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy) |
| CIAC | Contribution In Aid of Construction |
| City of Gillette | Gillette, Wyoming |
| Colorado Electric | Black Hills Colorado Electric Utility Company, LP, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy) |
| Colorado Gas | Black Hills Colorado Gas Utility Company, LP, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy) |
| Colorado IPP | Black Hills Colorado IPP, LLC a 50.1% owned subsidiary of Black Hills Electric Generation |
| Consolidated Indebtedness to Capitalization Ratio | Any Indebtedness outstanding at such time, divided by Capital at such time. Capital being Consolidated Net-Worth (excluding noncontrolling interest and including the aggregate outstanding amount of RSNs) plus Consolidated Indebtedness (including letters of credit, certain guarantees issued and excluding RSNs) as defined within the current Credit Agreement. |
| 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. |
| Cost of Service Gas Program (COSG) | Proposed Cost of Service Gas Program designed to provide long-term natural gas price stability for the Company’s utility customers, along with a reasonable expectation of customer savings over the life of the program. |
| CP Program | Commercial Paper Program |
| CPUC | Colorado Public Utilities Commission |
| CVA | Credit Valuation Adjustment |
| Dodd-Frank | Dodd-Frank Wall Street Reform and Consumer Protection Act |
| DSM | Demand Side Management |
| Dth | Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu) |
| ECA | Energy Cost Adjustment - adjustments that allow us to pass the prudently-incurred cost of fuel and purchased energy through to customers. |
| Equity Unit | Each Equity Unit has a stated amount of $50, consisting of a purchase contract issued by BHC to purchase shares of BHC common stock and a 1/20, or 5% undivided beneficial ownership interest in $1,000 principal amount of BHC RSNs due 2028. |
| FASB | Financial Accounting Standards Board |
| FERC | United States Federal Energy Regulatory Commission |
| Fitch | Fitch Ratings |
| GAAP | Accounting principles generally accepted in the United States of America |
| Global Settlement | Settlement with a utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders. |
| GSRS | Gas System Reliability Surcharge |
| 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. |
| Iowa Gas | Black Hills Iowa Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy) |
| IPP | Independent power producer |
| IRS | United States Internal Revenue Service |

| | |
|---|---|
| Kansas Gas | Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy) |
| 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. |
| MRP | Meter Relocation Program |
| MW | Megawatts |
| MWh | Megawatt-hours |
| Nebraska Gas | Black Hills Nebraska Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy) |
| NGL | Natural Gas Liquids (1 barrel equals 6 Mcfe) |
| NOL | Net Operating Loss |
| NPSC | Nebraska Public Service Commission |
| NYMEX | New York Mercantile Exchange |
| NYSE | New York Stock Exchange |
| Peak View Wind Project | $109 million 60 MW wind generating project for Colorado Electric, adjacent to Busch Ranch wind farm |
| PPA | Power Purchase Agreement |
| Revolving Credit Facility | Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2021. |
| RMNG | Rocky Mountain Natural Gas, a regulated gas utility acquired in the SourceGas Acquisition that provides regulated transmission and wholesale natural gas service to Black Hills Gas in western Colorado (doing business as Black Hills Energy) |
| RSNs | Remarketable junior subordinated notes, issued on November 23, 2015 |
| SDPUC | South Dakota Public Utilities Commission |
| SEC | U. S. Securities and Exchange Commission |
| SourceGas | SourceGas Holdings LLC and its subsidiaries, a gas utility owned by funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co. (NYSE:GE) that was acquired on February 12, 2016, and is now named Black Hills Gas Holdings, LLC (doing business as Black Hills Energy) |
| SourceGas Acquisition | The acquisition of SourceGas Holdings, LLC by Black Hills Utility Holdings |
| SourceGas Transaction | On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing. |
| S&P | Standard and Poor’s, a division of The McGraw-Hill Companies, Inc. |
| South Dakota Electric | Includes Black Hills Power operations in South Dakota, Wyoming and Montana |
| SSIR | System Safety and Integrity Rider |
| TCA | Transmission Cost Adjustment -- adjustments passed through to the customer based on transmission costs that are higher or lower than the costs approved in the rate case. |
| VIE | Variable interest entity |
| Winter Storm Atlas | An October 2013 blizzard that impacted South Dakota Electric. It was the second most severe blizzard in Rapid City’s history. |

| | |
|---|---|
| WRDC | Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings |
| Wyodak Plant | Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, is owned 80% by Pacificorp and 20% by Black Hills Energy South Dakota. Our WRDC mine supplies all of the fuel for the plant. |
| Wyoming Electric | Includes Cheyenne Light's electric utility operations |
| Wyoming Gas | Includes Cheyenne Light's natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Wyoming gas operations |

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

| (unaudited) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| | (in thousands, except per share amounts) | | | |
| Revenue | $347,978 | $325,441 | $901,981 | $775,400 |
| Operating expenses: | | | | |
| Fuel, purchased power and cost of natural gas sold | 98,164 | 84,489 | 317,941 | 256,345 |
| Operations and maintenance | 117,374 | 112,541 | 239,504 | 219,603 |
| Depreciation, depletion and amortization | 48,663 | 47,305 | 97,310 | 91,712 |
| Taxes - property, production and severance | 13,743 | 12,760 | 27,712 | 24,877 |
| Impairment of long-lived assets | — | 25,497 | — | 39,993 |
| Other operating expenses | 1,168 | 7,551 | 3,137 | 33,982 |
| Total operating expenses | 279,112 | 290,143 | 685,604 | 666,512 |
| Operating income | 68,866 | 35,298 | 216,377 | 108,888 |
| Other income (expense): | | | | |
| Interest charges - | | | | |
| Interest expense incurred (including amortization of debt issuance costs, premiums and discounts) | (35,098) | (34,609) | (70,194) | (66,683) |
| Allowance for funds used during construction - borrowed | 822 | 754 | 1,308 | 1,255 |
| Capitalized interest | 130 | 268 | 299 | 503 |
| Interest income | 257 | 946 | 298 | 1,601 |
| Allowance for funds used during construction - equity | 794 | 982 | 1,286 | 1,689 |
| Other income (expense), net | (58) | (47) | (160) | 641 |
| Total other income (expense), net | (33,153) | (31,706) | (67,163) | (60,994) |
| Income before income taxes | 35,713 | 3,592 | 149,214 | 47,894 |
| Income tax benefit (expense) | (10,402) | (309) | (43,757) | (4,561) |
| Net income | 25,311 | 3,283 | 105,457 | 43,333 |
| Net income attributable to noncontrolling interest | (3,116) | (2,614) | (6,739) | (2,662) |
| Net income available for common stock | $22,195 | $669 | $98,718 | $40,671 |
| Earnings per share of common stock: | | | | |
| Earnings per share, Basic | $0.42 | $0.01 | $1.86 | $0.79 |
| Earnings per share, Diluted | $0.40 | $0.01 | $1.79 | $0.78 |
| Weighted average common shares outstanding: | | | | |
| Basic | 53,229 | 51,514 | 53,191 | 51,279 |
| Diluted | 55,384 | 52,986 | 55,179 | 52,454 |
| Dividends declared per share of common stock | $0.445 | $0.420 | $0.890 | $0.840 |

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 COMPREHENSIVE INCOME (LOSS)

| (unaudited) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| | (in thousands) | | | |
| Net income (loss) | $25,311 | $3,283 | $105,457 | $43,333 |
| Other comprehensive income (loss), net of tax: | | | | |
| Reclassification adjustments of benefit plan liability - prior service cost (net of tax (expense) benefit of $18 and $19 for the three months ended June 30, 2017 and 2016 and $35 and $38 for the six months ended June 30, 2017 and 2016, respectively) | (31) | (36) | (62) | (72) |
| Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(146) and $(173) for the three months ended June 30, 2017 and 2016 and $(300) and $(346) for the six months ended June 30, 2017 and 2016, respectively) | 268 | 321 | 528 | 643 |
| Derivative instruments designated as cash flow hedges: | | | | |
| Net unrealized gains (losses) on interest rate swaps (net of tax of $0 and $4,440 for the three months ended June 30, 2017 and 2016 and $0 and $10,767 for the six months ended June 30, 2017 and 2016, respectively) | — | (8,174) | — | (19,898) |
| Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(249) and $(294) for the three months ended June 30, 2017 and 2016 and $(530) and $(592) for the six months ended June 30, 2017 and 2016, respectively) | 464 | 546 | 985 | 1,098 |
| Net unrealized gains (losses) on commodity derivatives (net of tax of $(194) and $906 for the three months ended June 30, 2017 and 2016 and $(536) and $98 for the six months ended June 30, 2017 and 2016, respectively) | 331 | (1,546) | 915 | (168) |
| Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $143 and $1,176 for the three months ended June 30, 2017 and 2016 and $249 and $2,476 for the six months ended June 30, 2017 and 2016, respectively) | (243) | (2,050) | (424) | (4,312) |
| Other comprehensive income (loss), net of tax | 789 | (10,939) | 1,942 | (22,709) |
| Comprehensive income (loss) | 26,100 | (7,656) | 107,399 | 20,624 |
| Less: comprehensive income attributable to noncontrolling interest | (3,116) | (2,614) | (6,739) | (2,662) |
| Comprehensive income (loss) available for common stock | $22,984 | $(10,270) | $100,660 | $17,962 |

See Note 13 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, 2017 | December 31, 2016 | June 30, 2016 |
|---|---|---|---|
| | (in thousands) | | |
| ASSETS | | | |
| Current assets: | | | |
| Cash and cash equivalents | $11,590 | $13,580 | $61,859 |
| Restricted cash and equivalents | 2,534 | 2,274 | 1,975 |
| Accounts receivable, net | 169,957 | 263,289 | 150,227 |
| Materials, supplies and fuel | 99,126 | 107,210 | 85,189 |
| Derivative assets, current | 1,148 | 4,138 | 4,030 |
| Regulatory assets, current | 53,061 | 49,260 | 54,856 |
| Other current assets | 21,840 | 27,063 | 30,652 |
| Total current assets | 359,256 | 466,814 | 388,788 |
| | | | |
| Investments | 12,761 | 12,561 | 12,363 |
| | | | |
| Property, plant and equipment | 6,533,581 | 6,412,223 | 6,209,816 |
| Less: accumulated depreciation and depletion | (1,981,880 ) | (1,943,234 ) | (1,819,886 ) |
| Total property, plant and equipment, net | 4,551,701 | 4,468,989 | 4,389,930 |
| | | | |
| Other assets: | | | |
| Goodwill | 1,299,454 | 1,299,454 | 1,303,453 |
| Intangible assets, net | 7,972 | 8,392 | 9,164 |
| Regulatory assets, non-current | 244,099 | 246,882 | 220,556 |
| Derivative assets, non-current | 37 | 222 | 226 |
| Other assets, non-current | 13,812 | 12,130 | 15,438 |
| Total other assets, non-current | 1,565,374 | 1,567,080 | 1,548,837 |
| | | | |
| TOTAL ASSETS | $6,489,092 | $6,515,444 | $6,339,918 |

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, 2017 | December 31, 2016 | June 30, 2016 |
|---|---|---|---|
| | (in thousands, except share amounts) | | |
| LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY | | | |
| Current liabilities: | | | |
| Accounts payable | $99,970 | $153,477 | $115,203 |
| Accrued liabilities | 201,993 | 244,034 | 218,250 |
| Derivative liabilities, current | 719 | 2,459 | 28,855 |
| Accrued income taxes, net | 5,160 | 12,552 | 10,624 |
| Regulatory liabilities, current | 17,305 | 13,067 | 34,275 |
| Notes payable | 107,975 | 96,600 | 75,000 |
| Current maturities of long-term debt | 5,743 | 5,743 | 930,743 |
| Total current liabilities | 438,865 | 527,932 | 1,412,950 |
| Long-term debt | 3,160,302 | 3,211,189 | 2,221,347 |
| Deferred credits and other liabilities: | | | |
| Deferred income tax liabilities, net, non-current | 589,189 | 535,606 | 530,746 |
| Derivative liabilities, non-current | 88 | 274 | 231 |
| Regulatory liabilities, non-current | 199,005 | 193,689 | 195,166 |
| Benefit plan liabilities | 176,102 | 173,682 | 173,347 |
| Other deferred credits and other liabilities | 135,510 | 138,643 | 122,015 |
| Total deferred credits and other liabilities | 1,099,894 | 1,041,894 | 1,021,505 |
| Commitments and contingencies (See Notes 8, 10, 15, 16) | | | |
| Redeemable noncontrolling interest | — | 4,295 | 4,171 |
| Equity: | | | |
| Stockholders’ equity — | | | |
| Common stock $1 par value; 100,000,000 shares authorized; issued 53,513,521; 53,397,467; and 52,299,075 shares, respectively | 53,514 | 53,397 | 52,299 |
| Additional paid-in capital | 1,145,493 | 1,138,982 | 1,072,927 |
| Retained earnings | 512,498 | 457,934 | 469,940 |
| Treasury stock, at cost – 39,329; 15,258; and 18,900 shares, respectively | (2,325) | (791) | (975) |
| Accumulated other comprehensive income (loss) | (32,941) | (34,883) | (31,764) |
| Total stockholders’ equity | 1,676,239 | 1,614,639 | 1,562,427 |
| Noncontrolling interest | 113,792 | 115,495 | 117,518 |
| Total equity | 1,790,031 | 1,730,134 | 1,679,945 |
| TOTAL LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY | $6,489,092 | $6,515,444 | $6,339,918 |

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, | |
|---|---|---|
| | 2017 | 2016 |
| Operating activities: | (in thousands) | |
| Net income (loss) | $ 105,457 | $ 40,671 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 97,310 | 91,712 |
| Deferred financing cost amortization | 4,138 | 2,857 |
| Impairment of long-lived assets | — | 39,993 |
| Stock compensation | 6,589 | 7,054 |
| Deferred income taxes | 51,153 | 32,606 |
| Employee benefit plans | 5,717 | 7,782 |
| Other adjustments, net | (6,515) | (6,332) |
| Changes in certain operating assets and liabilities: | | |
| Materials, supplies and fuel | 7,720 | 17,722 |
| Accounts receivable, unbilled revenues and other operating assets | 97,902 | 82,361 |
| Accounts payable and other operating liabilities | (113,541) | (124,695) |
| Regulatory assets - current | 3,086 | 1,862 |
| Regulatory liabilities - current | 5,908 | 2,994 |
| Contributions to defined benefit pension plans | — | (10,200) |
| Other operating activities, net | (2,055) | (2,884) |
| Net cash provided by (used in) operating activities | 262,869 | 183,503 |
| | | |
| Investing activities: | | |
| Property, plant and equipment additions | (163,768) | (199,854) |
| Acquisition, net of long term debt assumed | — | (1,124,238) |
| Other investing activities | (22) | (649) |
| Net cash provided by (used in) investing activities | (163,790) | (1,324,741) |
| | | |
| Financing activities: | | |
| Dividends paid on common stock | (47,544) | (43,265) |
| Common stock issued | 2,965 | 57,490 |
| Sale of noncontrolling interest | — | 216,370 |
| Net (payments) borrowings of short-term debt | 11,375 | (1,800) |
| Long-term debt - issuances | — | 574,672 |
| Long-term debt - repayments | (52,871) | (41,436) |
| Distributions to noncontrolling interest | (8,335) | — |
| Other financing activities | (6,659) | 205 |
| Net cash provided by (used in) financing activities | (101,069) | 762,236 |
| Net change in cash and cash equivalents | (1,990) | (379,002) |
| Cash and cash equivalents, beginning of period | 13,580 | 440,861 |
| Cash and cash equivalents, end of period | $ 11,590 | $ 61,859 |

See Note 14 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 2016 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 2016 Annual Report on Form 10-K filed with the SEC.

Segment Reporting

We conduct our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation, Mining and Oil and Gas. Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States.

Use of Estimates and Basis of Presentation

The information furnished in the accompanying Condensed Consolidated Financial Statements reflects certain estimates required and all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the June 30, 2017, December 31, 2016, and June 30, 2016 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 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, 2017 and June 30, 2016, and our financial condition as of June 30, 2017, December 31, 2016, and June 30, 2016, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. June 30, 2017 reflects a full six months of activity from the SourceGas Acquisition on February 12, 2016, as compared to the six months ended June 30, 2016 which reflects a partial period of approximately 4.5 months. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

Revisions

Certain revisions have been made to prior years' financial information to conform to the current year presentation. The Company revised its presentation of cash as of December 31, 2016. The Company has banking arrangements at certain financial institutions whereby if required, payments of one account are cleared with cash from other accounts at the same financial institution; therefore, book overdrafts are presented on a combined basis by bank as cash and cash equivalents. Prior year amounts were corrected to conform with the current year presentation, which decreased cash and cash equivalents and accounts payable by $55 million as of June 30, 2016, and decreased net cash flows provided by operations by $39 million for the six months ended June 30, 2016. We assessed the materiality of these changes, taking into account quantitative and qualitative factors, and determined them to be immaterial to the condensed consolidated balance sheet as of June 30, 2016 and to the Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2016. There is no impact to the Condensed Consolidated Statements of Income or the Condensed Consolidated Statements of Comprehensive Income for any period reported.

Recently Issued and Adopted Accounting Standards

Compensation - Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost, ASU 2017-07

In March 2017, the FASB issued ASU 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost. The changes to the standard require employers to report the service cost component in the same line item(s) as other compensation costs, and require the other components of net periodic pension and post-retirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component may be eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. This ASU will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and post-retirement benefit costs in the income statement. The capitalization of the service cost component of net period pension and post-retirement benefit costs in assets will be applied on a prospective basis. This new guidance is effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. We continue to assess the impact of this new standard on our financial statements and disclosures, and we monitor regulated utility industry implementation discussions and guidance. The presentation changes required for net periodic pension and post-retirement costs will result in offsetting changes to Operating income and Other income and are not expected to be material. We will implement this standard effective January 1, 2018.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments, ASU 2016-15

In August 2016, the FASB issued ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force). This ASU requires changes in the presentation of certain items including but not limited to debt prepayment or debt extinguishment costs; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies and distributions received from equity method investees. The ASU will be effective for fiscal years beginning after December 15, 2017. We will use the retrospective transition method to adopt this standard with fiscal years beginning after December 15, 2017. This standard will not have a material impact on our financial position, results of operations or cash flows.

Improvements to Employee Share-Based Payment Accounting, ASU 2016-09

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting. This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early adoption permitted. Certain amendments of this guidance are to be applied retrospectively and others prospectively. We implemented this ASU effective January 1, 2017, recording a cumulative-effect adjustment to retained earnings as of the date of adoption of $3.2 million in the Condensed Consolidated Balance Sheets, representing previously recorded forfeitures and excess tax benefits generated in years prior to 2017 that were previously not recognized in stockholders' equity due to NOLs in those years. Adoption of this ASU did not have a material impact on our consolidated financial position, results of operations or cash flows.

Leases, ASU 2016-02

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which supersedes ASC 840, Leases. This ASU requires lessees to recognize a right-of-use asset and lease liability on the balance sheet for all leases with a term greater than 12 months, whereas today only financing type lease liabilities (capital leases) are recognized on the balance sheet. In addition, the definition of a lease has been revised in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement which may result in changes to the classification of an arrangement as a lease. The ASU does not significantly change the lessees' recognition, measurement and presentation of expenses and cash flows from the previous accounting standard. Lessors' accounting under the ASU is largely unchanged from the previous accounting standard. The ASU expands the disclosure requirements of lease arrangements. Lessees and lessors will use a modified retrospective transition approach, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. The guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted.

We currently expect to adopt this standard on January 1, 2019. We continue to evaluate the impact of this new standard on our financial position, results of operations and cash flows as well as monitor emerging guidance on such topics as easements and right of ways, pipeline laterals, purchase power agreements, pole attachments and other industry-related areas. We also expect to implement changes to systems, processes and procedures in order to recognize and measure leases recorded on the balance sheet that are currently classified as operating leases.

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. The new disclosure requirements will provide information about the nature, amount, timing and uncertainty of revenue and cash flows from revenue contracts with customers. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017 with early adoption on January 1, 2017 permitted. Entities will have the option of using either a full retrospective or modified retrospective approach to adopting this guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption.

We currently expect to implement the standard on a modified retrospective basis effective January 1, 2018. We continue to actively assess all of our sources of revenue to determine the impact that adoption of the new standard will have on our financial position, results of operations and cash flows. Our evaluation includes identifying revenue streams by like contracts to allow for ease of implementation. A majority of our revenues are from regulated tariff offerings that provide natural gas or electricity with a defined contractual term. For such arrangements, we expect that revenue from contracts with the customer will be equivalent to the electricity or gas delivered in that period. Therefore, we do not expect there will be a significant shift in the timing or pattern of revenue recognition for regulated tariff based sales. The evaluation of other revenue streams is ongoing, including our non-regulated revenues and those tied to longer term contractual commitments. We also continue to monitor outstanding industry implementation issues and assess the impacts to our current accounting policies and/or patterns of revenue recognition.

(2) ACQUISITION

2016 Acquisition of SourceGas

On February 12, 2016, Black Hills Corporation acquired SourceGas (now referred to as Black Hills Gas Holdings). We acquired SourceGas for $1.1 billion of cash plus the assumption of $760 million of long-term debt. We finalized our purchase price allocation at December 31, 2016. See Note 2 of our Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K for more details.

Pro Forma Results

The following unaudited pro forma financial information reflects the consolidated results of operations as if the SourceGas Acquisition had taken place on January 1, 2015. The unaudited pro forma financial information is presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or our future consolidated results.

The pro forma financial information does not reflect any potential cost savings from operating efficiencies resulting from the acquisition and does not include certain acquisition-related costs that are not expected to have a continuing impact on the combined consolidated results. Pro forma results for the three and six months ended June 30, 2016 exclude approximately $4.0 million and $20 million, respectively, of after-tax transaction costs, professional fees, employee related expenses and other miscellaneous costs.

| | Three Months Ended June 30, 2016 | Six Months Ended June 30, 2016 |
|---|---|---|
| | (in thousands, except per share amounts) | |
| Revenue | $325,441 | $854,362 |
| Net income (loss) available for common stock | $4,658 | $72,978 |
| Earnings (loss) per share, Basic | $0.09 | $1.42 |
| Earnings (loss) per share, Diluted | $0.09 | $1.39 |

Redemption of seller's noncontrolling interest

As part of the SourceGas Transaction, a seller retained a 0.5% noncontrolling interest and we entered into an associated option agreement with the holder of the 0.5% retained interest. The terms of the agreement provided us a call option to purchase the remaining interest beginning 366 days after the initial close of the SourceGas Transaction. In March 2017, we exercised our call option and purchased the remaining 0.5% equity interest in SourceGas for $5.6 million.

(3) BUSINESS SEGMENT INFORMATION

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

| Three Months Ended June 30, 2017 | External Operating Revenue | Inter-company Operating Revenue | Net Income (Loss) Available for Common Stock |
|---|---|---|---|
| Segment: | | | |
| Electric | $165,517 | $ 2,936 | $18,832 |
| Gas | 166,439 | 8 | (272) |
| Power Generation (b) | 1,470 | 20,325 | 5,332 |
| Mining | 8,403 | 6,543 | 2,681 |
| Oil and Gas | 6,149 | — | (1,946) |
| Corporate activities (c) | — | — | (2,432) |
| Inter-company eliminations | — | (29,812) | — |
| Total | $347,978 | $ — | $22,195 |

Three Months Ended June 30, 2016 External Inter-company

| | Operating Revenue | Operating Revenue | Net Income (Loss) Available for Common Stock |
|---|---|---|---|
| Segment: | | | |
| Electric | $158,560 | $ 2,921 | $19,229 |
| Gas | 153,767 | (1,806 ) | 987 |
| Power Generation [(b)] | 1,546 | 20,168 | 5,683 |
| Mining | 3,922 | 7,125 | 724 |
| Oil and Gas [(e)] | 7,646 | — | (19,424 ) |
| Corporate activities [(c)] | — | — | (6,530 ) |
| Inter-company eliminations | — | (28,408 ) | — |
| Total | $325,441 | $ — | $669 |

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| Six Months Ended June 30, 2017 | External Operating Revenue | Inter-company Operating Revenue | Net Income (Loss) Available for Common Stock |
|---|---|---|---|
| Segment: | | | |
| Electric | $337,687 | $ 6,790 | $41,062 |
| Gas [(a)] | 531,340 | 17 | 45,738 |
| Power Generation [(b)] | 3,572 | 41,790 | 11,862 |
| Mining | 16,758 | 14,734 | 5,571 |
| Oil and Gas | 12,624 | — | (4,897) |
| Corporate activities [(c)(d)] | — | — | (618) |
| Inter-company eliminations | — | (63,331) | — |
| Total | $901,981 | $ — | $98,718 |

| Six Months Ended June 30, 2016 | External Operating Revenue | Inter-company Operating Revenue | Net Income (Loss) Available for Common Stock |
|---|---|---|---|
| Segment: | | | |
| Electric | $322,091 | $ 6,666 | $38,444 |
| Gas [(a)] | 422,434 | — | 32,914 |
| Power Generation [(b)] | 3,398 | 41,624 | 14,265 |
| Mining | 11,456 | 15,873 | 3,662 |
| Oil and Gas [(e)] | 16,021 | — | (26,448) |
| Corporate activities [(c)(d)] | — | — | (22,166) |
| Inter-company eliminations | — | (64,163) | — |
| Total | $775,400 | $ — | $40,671 |

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(a) Gas Utility revenue increased for the six months ended June 30, 2017 compared to the same periods in the prior year primarily due to the addition of the SourceGas utilities on February 12, 2016.

(b) Net income (loss) available for common stock for the three and six months ended June 30, 2017 was net of net income attributable to noncontrolling interests of $3.1 million and $6.6 million, respectively, and $2.6 million for both the three and six months ended June 30, 2016.

(c) Net income (loss) available for common stock for the three and six months ended June 30, 2017 and June 30, 2016 included incremental, non-recurring acquisition costs, net of tax of $0.3 million and $1.2 million, and $4.1 million and $20 million respectively. The three and six months ended June 30, 2016 also included $2.0 million and $5.7 million, respectively, of after-tax internal labor costs attributable to the acquisition.

(d) Net income (loss) available for common stock for the six months ended June 30, 2017 included a $1.4 million tax benefit recognized from carryback claims for specified liability losses involving prior tax years. Net income (loss) available for common stock for the six months ended June 30, 2016 included tax benefits of approximately $4.4 million as a result of the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016. See Note 18.

(e) Net income (loss) available for common stock for the three and six months ended June 30, 2016 included non-cash after-tax impairments of oil and gas properties of $16 million and $25 million. See Note 17 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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, 2017 | December 31, 2016 | June 30, 2016 |
|---|---|---|---|
| Segment: | | | |
| Electric [(a)] | $2,901,570 | $2,859,559 | $2,755,695 |
| Gas | 3,242,461 | 3,307,967 | 3,118,626 |
| Power Generation [(a)] | 66,292 | 73,445 | 80,360 |
| Mining | 67,365 | 67,347 | 71,319 |
| Oil and Gas [(b)] | 103,044 | 96,435 | 171,239 |
| Corporate activities | 108,360 | 110,691 | 142,679 |
| Total assets | $6,489,092 | $6,515,444 | $6,339,918 |

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(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from 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.

(b) As a result of continued low commodity prices and our decision to divest non-core oil and gas assets, we recorded non-cash impairments of $107 million for the year ended December 31, 2016 and $40 million for the six months ended June 30, 2016. See Note 17 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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(4) ACCOUNTS RECEIVABLE

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

| June 30, 2017 | Accounts Receivable, Trade | Unbilled Revenue | Less Allowance for Doubtful Accounts | Accounts Receivable, net |
|---|---|---|---|---|
| Electric Utilities | $ 41,635 | $ 33,686 | $ (466 ) | $ 74,855 |
| Gas Utilities | 62,908 | 26,584 | (2,535 ) | 86,957 |
| Power Generation | 877 | — | — | 877 |
| Mining | 2,904 | — | — | 2,904 |
| Oil and Gas | 3,280 | — | (83 ) | 3,197 |
| Corporate | 1,167 | — | — | 1,167 |
| Total | $ 112,771 | $ 60,270 | $ (3,084 ) | $ 169,957 |

| December 31, 2016 | Accounts Receivable, Trade | Unbilled Revenue | Less Allowance for Doubtful Accounts | Accounts Receivable, net |
|---|---|---|---|---|
| Electric Utilities | $ 41,730 | $ 36,463 | $ (353 ) | $ 77,840 |
| Gas Utilities | 88,168 | 88,329 | (2,026 ) | 174,471 |
| Power Generation | 1,420 | — | — | 1,420 |
| Mining | 3,352 | — | — | 3,352 |
| Oil and Gas | 3,991 | — | (13 ) | 3,978 |
| Corporate | 2,228 | — | — | 2,228 |
| Total | $ 140,889 | $ 124,792 | $ (2,392 ) | $ 263,289 |

| June 30, 2016 | Accounts Receivable, Trade | Unbilled Revenue | Less Allowance for Doubtful Accounts | Accounts Receivable, net |
|---|---|---|---|---|
| Electric Utilities | $ 40,991 | $ 34,174 | $ (716 ) | $ 74,449 |
| Gas Utilities | 47,600 | 23,124 | (2,997 ) | 67,727 |
| Power Generation | 1,229 | — | — | 1,229 |
| Mining | 1,114 | — | — | 1,114 |
| Oil and Gas | 3,094 | — | (13 ) | 3,081 |
| Corporate | 2,627 | — | — | 2,627 |
| Total | $ 96,655 | $ 57,298 | $ (3,726 ) | $ 150,227 |

(5) REGULATORY ACCOUNTING

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

| | Maximum Amortization (in years) | As of June 30, 2017 | As of December 31, 2016 | As of June 30, 2016 |
|---|---|---|---|---|
| Regulatory assets | | | | |
| Deferred energy and fuel cost adjustments - current [a][d] | 1 | $20,761 | $17,491 | $20,603 |
| Deferred gas cost adjustments [a][d] | 1 | 9,060 | 15,329 | 12,122 |
| Gas price derivatives [a] | 3.5 | 11,159 | 8,843 | 11,515 |
| Deferred taxes on AFUDC [b] | 45 | 15,322 | 15,227 | 13,879 |
| Employee benefit plans [c] | 12 | 107,419 | 108,556 | 109,522 |
| Environmental [a] | subject to approval | 1,070 | 1,108 | 1,144 |
| Asset retirement obligations [a] | 44 | 510 | 505 | 505 |
| Loss on reacquired debt [a] | 30 | 21,466 | 22,266 | 3,061 |
| Renewable energy standard adjustment [b] | 5 | 768 | 1,605 | 2,679 |
| Deferred taxes on flow through accounting [c] | 35 | 40,586 | 37,498 | 31,554 |
| Decommissioning costs [e] | 6 | 14,681 | 16,859 | 18,399 |
| Gas supply contract termination | 5 | 22,793 | 26,666 | 28,385 |
| Other regulatory assets [a] [e] | 15 | 31,565 | 24,189 | 22,044 |
| | | $297,160 | $296,142 | $275,412 |
| | | | | |
| Regulatory liabilities | | | | |
| Deferred energy and gas costs [a] [d] | 1 | $16,767 | $10,368 | $32,868 |
| Employee benefit plan costs and related deferred taxes [c] | 12 | 67,297 | 68,654 | 62,712 |
| Cost of removal [a] | 44 | 125,247 | 118,410 | 126,002 |
| Revenue subject to refund | 1 | 1,518 | 2,485 | 1,616 |
| Other regulatory liabilities [c] | 25 | 5,481 | 6,839 | 6,243 |
| | | $216,310 | $206,756 | $229,441 |

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(a) We are allowed 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.

(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. 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.

(e) In accordance with a settlement agreement approved by the SDPUC on June 16, 2017, the amortization of South Dakota Electric’s decommissioning costs of approximately $11 million, vegetation management costs of approximately $14 million, and Winter Storm Atlas costs of approximately $2.0 million will be amortized over 6 years, effective July 1, 2017. Decommissioning costs and Winter Storm Atlas costs were previously amortized over a 10 year period ending September 30, 2024. The vegetation management costs were previously unamortized. The change in amortization periods for these costs will increase annual amortization expense by approximately $2.7 million.

## (6) 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, 2017 | December 31, 2016 | June 30, 2016 |
|---|---|---|---|
| Materials and supplies | $72,397 | $68,456 | $67,440 |
| Fuel - Electric Utilities | 3,106 | 3,667 | 4,659 |
| Natural gas in storage held for distribution | 23,623 | 35,087 | 13,090 |
| Total materials, supplies and fuel | $99,126 | $107,210 | $85,189 |

## (7) EARNINGS PER SHARE

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Net income (loss) available for common stock | $22,195 | $ 669 | $98,718 | $40,671 |
| Weighted average shares - basic | 53,229 | 51,514 | 53,191 | 51,279 |
| Dilutive effect of: | | | | |
| Equity Units [(a)] | 1,977 | 1,362 | 1,796 | 1,068 |
| Equity compensation | 178 | 110 | 192 | 107 |
| Weighted average shares - diluted | 55,384 | 52,986 | 55,179 | 52,454 |

(a) Calculated using the treasury stock method.

The following outstanding securities were excluded in the computation of diluted net income (loss) per share as their inclusion would have been anti-dilutive (in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Equity compensation | — | 4 | — | 10 |
| Anti-dilutive shares | — | 4 | — | 10 |

(8) NOTES PAYABLE AND LONG-TERM DEBT

We had the following notes payable outstanding in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

| | June 30, 2017 | | December 31, 2016 | | June 30, 2016 | |
|---|---|---|---|---|---|---|
| | Balance Outstanding | Letters of Credit | Balance Outstanding | Letters of Credit | Balance Outstanding | Letters of Credit |
| Revolving Credit Facility | $— | $24,540 | $96,600 | $36,000 | $75,000 | $24,700 |
| CP Program | 107,975 | — | — | — | — | — |
| Total | $107,975 | $24,540 | $96,600 | $36,000 | $75,000 | $24,700 |

Revolving Credit Facility and CP Program

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extend the term through August 9, 2021 with two one-year extension options (subject to consent from lenders). This facility is 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 total commitments of the facility up to $1.0 billion. 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 either S&P or Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.250%, 1.250%, and 1.250%, respectively, at June 30, 2017. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

On December 22, 2016, we implemented a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption. Our net amount borrowed under the CP Program during the six months ended June 30, 2017 and our notes outstanding as of June 30, 2017 were $108 million. As of June 30, 2017, the weighted average interest rate on CP Program borrowings was 1.41%.

Debt Covenants

On December 7, 2016, we amended our Revolving Credit Facility and term loan agreements, allowing the exclusion of the Remarketable Junior Subordinated Notes (RSNs) from our Consolidated Indebtedness to Capitalization Ratio covenant calculation. Under the amended and restated Revolving Credit Facility and term loan agreements, we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. Our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit and certain guarantees issued and excludes RSNs by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs.

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

| | As of June 30, 2017 | Covenant Requirement |
|---|---|---|
| Consolidated Indebtedness to Capitalization Ratio | 61% | Less than 65% |

As of June 30, 2017, we were in compliance with this covenant.

Long-Term Debt

On May 16, 2017, we paid down $50 million on our Corporate term loan due August 9, 2019. On July 17, 2017, we paid down an additional $50 million on the same term loan. Short-term borrowings from our CP program were used to fund the payments on the Corporate term loan.

(9) EQUITY

A summary of the changes in equity is as follows:

| Six Months Ended June 30, 2017 | Total Stockholders' Equity | Noncontrolling Interest | Total Equity |
|---|---|---|---|
| | | (in thousands) | |
| Balance at December 31, 2016 | $ 1,614,639 | $ 115,495 | $ 1,730,134 |
| Net income (loss) | 98,718 | 6,632 | 105,350 |
| Other comprehensive income (loss) | 1,942 | — | 1,942 |
| Dividends on common stock | (47,544) | — | (47,544) |
| Share-based compensation | 4,133 | — | 4,133 |
| Issuance of common stock | — | — | — |
| Dividend reinvestment and stock purchase plan | 1,530 | — | 1,530 |
| Redeemable noncontrolling interest | (886) | — | (886) |
| Cumulative effect of ASU 2016-09 implementation | 3,714 | — | 3,714 |
| Other stock transactions | (7) | — | (7) |
| Distribution to noncontrolling interest | — | (8,335) | (8,335) |
| Balance at June 30, 2017 | $ 1,676,239 | $ 113,792 | $ 1,790,031 |

| Six Months Ended June 30, 2016 | Total Stockholders' Equity | Noncontrolling Interest | Total Equity |
|---|---|---|---|
| | | (in thousands) | |
| Balance at December 31, 2015 | $ 1,465,867 | $ — | $ 1,465,867 |
| Net income (loss) | 40,671 | 2,632 | 43,303 |
| Other comprehensive income (loss) | (22,709) | — | (22,709) |
| Dividends on common stock | (43,270) | — | (43,270) |
| Share-based compensation | 2,192 | — | 2,192 |
| Issuance of common stock | 55,802 | — | 55,802 |
| Dividend reinvestment and stock purchase plan | 1,478 | — | 1,478 |
| Other stock transactions | (20) | — | (20) |
| Sale of noncontrolling interest | 62,416 | 114,886 | 177,302 |
| Balance at June 30, 2016 | $ 1,562,427 | $ 117,518 | $ 1,679,945 |

At-the-Market Equity Offering Program

On March 18, 2016, we implemented an ATM equity offering program allowing us to sell shares of our common stock with an aggregate value of up to $200 million. The shares may be offered from time to time pursuant to a sales agreement dated March 18, 2016. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. We did not issue any common shares during the six months ended June 30, 2017. During the three months ended June 30, 2016, we sold 809,649 common shares for $49 million, net of $0.5 million in commissions, under the ATM equity offering program. During the six months ended June 30, 2016, we sold and issued an aggregate of 930,649 shares of common stock under the ATM equity offering program for $56 million, net of $0.6 million in commissions with settlement dates through June 30, 2016. On August 4, 2017, the Company plans to file for renewal of the ATM equity offering program initiated in 2016 which resets the size of the ATM equity offering program to an aggregate sales price of up to $300 million.

Sale of Noncontrolling Interest in Subsidiary

Black Hills Colorado IPP owns a 200 MW, combined-cycle natural gas generating facility located in Pueblo, Colorado. On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third-party buyer. FERC approval of the sale was received on March 29, 2016. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric.

This partial sale was required to be recorded as an equity transaction with no resulting gain or loss on the sale. Further, GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. Distributions of net income attributable to noncontrolling interests are due within 30 days following the end of a quarter, but may be withheld as necessary by Black Hills Electric Generation.

Black Hills Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest. Black Hills Electric Generation has been determined to be the primary beneficiary of the VIE as Black Hills Electric Generation is the operator and manager of the generation facility and, as such, has the power to direct the activities that most significantly impact Black Hills Colorado IPP's economic performance. Black Hills Electric Generation, as the primary beneficiary, continues to consolidate Black Hills Colorado IPP. Black Hills Colorado IPP has not received financial or other support from the Company outside of pre-existing contractual arrangements during the reporting period. Black Hills Colorado IPP does not have any debt and its cash flows from operations are sufficient to support its ongoing operations.

We have recorded the following assets and liabilities on our consolidated balance sheets related to the VIE described above as of:

| | June 30, 2017 | December 31, 2016 | June 30, 2016 |
|---|---|---|---|
| | (in thousands) | | |
| Assets | | | |
| Current assets | $12,042 | $12,627 | $12,681 |
| Property, plant and equipment of variable interest entities, net | $214,239 | $218,798 | $224,128 |
| | | | |
| Liabilities | | | |
| Current liabilities | $2,651 | $4,342 | $4,174 |

## (10) 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 2016 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, our retail natural gas marketing activities, and our fuel procurement for certain of our gas-fired generation assets.

### 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 on 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.

Our derivative and hedging activities recorded in the accompanying Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Income and Condensed Consolidated Statements of Comprehensive Income are detailed below and in Note 11.

### Oil and Gas

We produce natural gas, NGLs 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 exchange traded futures, swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on our futures and swaps. 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, net of balance sheet offsetting as permitted by GAAP. 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.

The contract or notional amounts and terms of the crude oil futures and natural gas futures and swaps held at our Oil and Gas segment are composed of short positions. We had the following short positions as of:

| | June 30, 2017 | | | December 31, 2016 | | | June 30, 2016 | |
|---|---|---|---|---|---|---|---|---|
| | Crude Oil Futures | Crude Oil Options | Natural Gas Futures and Swaps | Crude Oil Futures | Crude Oil Options | Natural Gas Futures and Swaps | Crude Oil Futures | Natural Gas Futures and Swaps |
| Notional [(a)] | 72,000 | 18,000 | 1,080,000 | 108,000 | 36,000 | 2,700,000 | 210,000 | 2,530,000 |
| Maximum terms in months [(b)] | 18 | 6 | 6 | 24 | 12 | 12 | 30 | 18 |

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(a) Crude oil futures and call options in Bbls, natural gas in MMBtus.
(b) Term reflects the maximum forward period hedged.

Based on June 30, 2017 prices, a $0.5 million gain would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

Utilities

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities' 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, fixed to float swaps 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.

For our regulated utilities' hedging plans, 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, or the Condensed Consolidated Statements of Comprehensive Income.

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from July 2017 through December 2020. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with forward contracts to deliver gas to our Choice Gas Program customers. The effective portion of the gain or loss on these designated derivatives is reported in AOCI in the accompanying Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Fuel, purchased power and cost of natural gas sold in the accompanying Condensed Consolidated Statements of Income. Effectiveness of our hedging position is evaluated at least quarterly.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held at our Utilities are composed of both long and short positions. We were in a net long position as of:

| | June 30, 2017 | | December 31, 2016 | | June 30, 2016 | |
|---|---|---|---|---|---|---|
| | Notional (MMBtus) | Maximum Term (months) [(a)] | Notional (MMBtus) | Maximum Term (months) [(a)] | Notional (MMBtus) | Maximum Term (months) [(a)] |
| Natural gas futures purchased | 11,060,000 | 42 | 14,770,000 | 48 | 18,080,000 | 54 |
| Natural gas options purchased, net | 1,640,000 | 20 | 3,020,000 | 5 | 3,770,000 | 20 |
| Natural gas basis swaps purchased | 10,070,000 | 42 | 12,250,000 | 48 | 15,320,000 | 54 |
| Natural gas over-the-counter swaps, net [(b)] | 5,200,000 | 23 | 4,622,302 | 28 | 5,029,500 | 23 |
| Natural gas physical contracts, net | 8,427,119 | 10 | 21,504,378 | 10 | 1,666,800 | 9 |

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(a) Term reflects the maximum forward period hedged.

(b) 2,480,000 MMBtus were designated as cash flow hedges for the natural gas fixed for float swaps purchased.

Based on June 30, 2017 prices, a $0.2 million loss would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

Financing Activities

In October 2015 and January 2016, we entered into forward starting interest rate swaps with a notional value totaling $400 million to reduce the interest rate risk associated with the anticipated issuance of senior notes. These swaps were settled at a loss of $29 million in connection with the issuance of our $400 million of unsecured ten-year senior notes on August 10, 2016. The effective portion of the loss in the amount of $28 million was recognized as a component of AOCI and will be recognized as a component of interest expense over the ten-year life of the $400 million unsecured senior note issued on August 19, 2016. Amortization of approximately $2.9 million, which includes the amortization of the $28 million loss currently deferred in AOCI will be recognized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. The ineffective portion of $1.0 million, related to the timing of the debt issuance, was recognized in earnings as a component of interest expense in 2016. 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, 2017 | December 31, 2016 | June 30, 2016 | | |
|---|---|---|---|---|---|
| | Designated Interest Rate Swaps | Designated Interest Rate Swap [(a)] | Designated Interest Rate Swap [(b)] | Designated Interest Rate Swap [(b)] | Designated Interest Rate Swaps [(a)] |
| Notional | $ — | $ 50,000 | $ 150,000 | $ 250,000 | $ 75,000 |
| Weighted average fixed interest rate | — % | 4.94 % | 2.09 % | 2.29 % | 4.97 % |
| Maximum terms in months | 0 | 1 | 10 | 10 | 6 |
| Derivative liabilities, current | $ — | $ 90 | $ 8,553 | $ 18,500 | $ 1,505 |

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(a) The $25 million in swaps expired in October 2016 and the $50 million in swaps expired in January 2017. These swaps were designated to borrowings on our Revolving Credit Facility and were priced using three-month LIBOR, matching the floating portion of the related borrowings.

(b) These swaps were settled and terminated in August 2016 in conjunction with the refinancing of acquired SourceGas debt.

Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income is presented below for the three and six months ended June 30, 2017 and 2016 (in thousands). Note that this presentation does not reflect gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

Three Months Ended June 30, 2017

| Derivatives in Cash Flow Hedging Relationships | Location of Reclassifications from AOCI into Income | Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements) | 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 | Interest expense | $ (713 ) | Interest expense | $ — |
| Commodity derivatives | Revenue | 430 | Revenue | — |
| Commodity derivatives | Fuel, purchased power and cost of natural gas sold | (44 ) | Fuel, purchased power and cost of natural gas sold | — |
| Total | | $ (327 ) | | $ — |

Three Months Ended June 30, 2016

| Derivatives in Cash Flow Hedging Relationships | Location of Reclassifications from AOCI into Income | Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements) | 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 | Interest expense | $ (840 ) | Interest expense | $ — |
| Commodity derivatives | Revenue | 3,287 | Revenue | — |
| Commodity derivatives | Fuel, purchased power and cost of natural gas sold | (61 ) | Fuel, purchased power and cost of natural gas sold | — |
| Total | | $ 2,386 | | $ — |

Six Months Ended June 30, 2017

| Derivatives in Cash Flow Hedging Relationships | Location of Reclassifications from AOCI into Income | Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements) | 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 | Interest expense | $ (1,515 ) | Interest expense | $ — |
| Commodity derivatives | Revenue | 659 | Revenue | — |
| Commodity derivatives | Fuel, purchased power and cost of natural gas sold | 14 | Fuel, purchased power and cost of natural gas sold | — |
| Total | | $ (842 ) | | $ — |

Six Months Ended June 30, 2016

| Derivatives in Cash Flow Hedging Relationships | Location of Reclassifications from AOCI into Income | Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements) | 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 | Interest expense | $ (1,690 ) | Interest expense | $ — |
| Commodity derivatives | Revenue | 6,939 | Revenue | — |
| Commodity derivatives | Fuel, purchased power and cost of natural gas sold | (151 ) | Fuel, purchased power and cost of natural gas sold | — |
| Total | | $ 5,098 | | $ — |

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss) for the three and six months ended June 30, 2017 and 2016. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the Consolidated Statements of Net Income as incurred.

| | Three Months Ended June 30, | |
|---|---|---|
| | 2017 | 2016 |
| | (In thousands) | |
| Increase (decrease) in fair value: | | |
| Interest rate swaps | $— | $(12,614) |
| Forward commodity contracts | 525 | (2,452 ) |
| Recognition of (gains) losses in earnings due to settlements: | | |
| Interest rate swaps | 713 | 840 |
| Forward commodity contracts | (386 ) | (3,226 ) |
| Total other comprehensive income (loss) from hedging | $852 | $(17,452) |

| | Six Months Ended June 30, | |
|---|---|---|
| | 2017 | 2016 |
| | (In thousands) | |
| Increase (decrease) in fair value: | | |
| Interest rate swaps | $— | $(30,665) |
| Forward commodity contracts | 1,451 | (266 ) |
| Recognition of (gains) losses in earnings due to settlements: | | |
| Interest rate swaps | 1,515 | 1,690 |
| Forward commodity contracts | (673 ) | 6,788 |
| Total other comprehensive income (loss) from hedging | $2,293 | $(22,453) |

Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income for the three and six months ended June 30, 2017 and 2016 (in thousands). Note that this presentation does not reflect gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

| | | Three Months Ended June 30, | |
|---|---|---|---|
| | | 2017 | 2016 |
| Derivatives Not Designated as Hedging Instruments | Location of Gain/(Loss) on Derivatives Recognized in Income | Amount of Gain/(Loss) on Derivatives Recognized in Income | Amount of Gain/(Loss) on Derivatives Recognized in Income |
| Commodity derivatives | Revenue | $26 | $ — |
| Commodity derivatives | Fuel, purchased power and cost of natural gas sold | (691 ) | 2,201 |
| | | $(665) | $ 2,201 |

| | | Six Months Ended June 30, | |
|---|---|---|---|
| | | 2017 | 2016 |
| Derivatives Not Designated as Hedging Instruments | Location of Gain/(Loss) on Derivatives Recognized in Income | Amount of Gain/(Loss) on Derivatives Recognized in Income | Amount of Gain/(Loss) on Derivatives Recognized in Income |
| Commodity derivatives | Revenue | $143 | $ — |
| Commodity derivatives | Fuel, purchased power and cost of natural gas sold | (1,500 ) | 2,835 |
| | | $(1,357) | $ 2,835 |

As discussed above, financial instruments used in our regulated utilities are not designated as cash flow hedges. However, there is no earnings impact because the unrealized gains and losses arising from the use of these financial instruments are recorded as Regulatory assets. The net unrealized losses included in our Regulatory assets related to the hedges in our Utilities were $11 million, $8.8 million and $12 million at June 30, 2017, December 31, 2016 and June 30, 2016, respectively.

## (11) 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, 9, 10 and 11 to the Consolidated Financial Statements included in our 2016 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 contracts for our Oil and Gas segment are valued using the market approach and include exchange-traded futures, basis swaps and call options. Fair value was derived using exchange quoted settlement 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.

Utilities Segments:

- The commodity contracts for our Utilities Segments, valued using the market approach, include exchange-traded futures, options, basis swaps and over-the-counter swaps and options (Level 2) for natural gas contracts. For exchange-traded futures, options and basis swap assets and liabilities, fair value was derived using broker quotes validated by the exchange settlement pricing for the applicable contract. For over-the-counter instruments, the fair value is obtained by utilizing a nationally recognized service that obtains observable inputs to compute the fair value, which we validate by comparing our valuation with the counterparty. The fair value of these swaps includes a CVA component based on the credit spreads of the counterparties when we are in an unrealized gain position or on our own credit spread when we are in an unrealized loss position.

Corporate Activities:

- As of June 30, 2017, we no longer have derivatives within our corporate activities as our interest rate swaps matured in January 2017. The interest rate swaps that were in place prior to January 2017 were valued using the market approach. We established fair value by obtaining price quotes directly from the counterparty which were based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty was 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 included a CVA component. The CVA considered 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 utilized observable inputs supporting a Level 2 disclosure by using the credit default spread of the obligor, if available, or a generic credit default spread curve that took into account our credit ratings, and the credit rating of our counterparty.

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 are gross assets and gross liabilities and related offsetting cash collateral and counterparty netting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments.

| | As of June 30, 2017 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty Netting | Total |
| | (in thousands) | | | | |
| Assets: | | | | | |
| Commodity derivatives — Oil and Gas | $ — | $ 770 | $ — | $ (230) | $ 540 |
| Commodity derivatives — Utilities | — | 1,622 | — | (977) | 645 |
| Total | $ — | $ 2,392 | $ — | $ (1,207) | $ 1,185 |
| | | | | | |
| Liabilities: | | | | | |
| Commodity derivatives — Oil and Gas | $ — | $ 44 | $ — | $ — | $ 44 |
| Commodity derivatives — Utilities | — | 12,331 | — | (11,568) | 763 |
| Total | $ — | $ 12,375 | $ — | $ (11,568) | $ 807 |

| | As of December 31, 2016 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty Netting | Total |
| | (in thousands) | | | | |
| Assets: | | | | | |
| Commodity derivatives — Oil and Gas | $ — | $ 2,886 | $ — | $ (2,733) | $ 153 |
| Commodity derivatives —Utilities | — | 7,469 | — | (3,262) | 4,207 |
| Total | $ — | $ 10,355 | $ — | $ (5,995) | $ 4,360 |
| | | | | | |
| Liabilities: | | | | | |
| Commodity derivatives — Oil and Gas | $ — | $ 1,586 | $ — | $ — | $ 1,586 |
| Commodity derivatives — Utilities | — | 12,201 | — | (11,144) | 1,057 |
| Interest rate swaps | — | 90 | — | — | 90 |
| Total | $ — | $ 13,877 | $ — | $ (11,144) | $ 2,733 |

| | As of June 30, 2016 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty Netting | Total |
| | (in thousands) | | | | |
| Assets: | | | | | |
| Commodity derivatives — Oil and Gas | $ — | $ 2,748 | $ — | $ (1,150) | $ 1,598 |
| Commodity derivatives — Utilities | — | 6,833 | — | (4,175) | 2,658 |
| Total | $ — | $ 9,581 | $ — | $ (5,325) | $ 4,256 |
| | | | | | |
| Liabilities: | | | | | |
| Commodity derivatives — Oil and Gas | $ — | $ 228 | $ — | $ — | $ 228 |
| Commodity derivatives — Utilities | — | 14,727 | — | (14,427) | 300 |
| Interest rate swaps | — | 28,558 | — | — | 28,558 |
| Total | $ — | $ 43,513 | $ — | $ (14,427) | $ 29,086 |

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 aside from 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.

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

As of June 30, 2017

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|---|---|---|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $ 548 | $ — |
| Commodity derivatives | Derivative assets — non-current | 31 | — |
| Commodity derivatives | Derivative liabilities — current | — | 167 |
| Commodity derivatives | Derivative liabilities — non-current | — | 32 |
| Total derivatives designated as hedges | | $ 579 | $ 199 |
| | | | |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $ 600 | $ — |
| Commodity derivatives | Derivative assets — non-current | 6 | — |
| Commodity derivatives | Derivative liabilities — current | — | 552 |
| Commodity derivatives | Derivative liabilities — non-current | — | 56 |
| Total derivatives not designated as hedges | | $ 606 | $ 608 |

As of December 31, 2016

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|---|---|---|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $ 1,161 | $ — |
| Commodity derivatives | Derivative assets — non-current | 124 | — |
| Commodity derivatives | Derivative liabilities — current | — | 1,090 |
| Commodity derivatives | Derivative liabilities — non-current | — | 238 |
| Interest rate swaps | Derivative liabilities — current | — | 90 |
| Total derivatives designated as hedges | | $ 1,285 | $ 1,418 |
| | | | |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $ 2,977 | $ — |
| Commodity derivatives | Derivative assets — non-current | 98 | — |
| Commodity derivatives | Derivative liabilities — current | — | 1,279 |
| Commodity derivatives | Derivative liabilities — non-current | — | 36 |
| Total derivatives not designated as hedges | | $ 3,075 | $ 1,315 |

As of June 30, 2016

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|---|---|---|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $ 2,549 | $ — |
| Commodity derivatives | Derivative assets — non-current | 81 | — |
| Commodity derivatives | Derivative liabilities — current | — | 44 |
| Commodity derivatives | Derivative liabilities — non-current | — | 226 |
| Interest rate swaps | Derivative liabilities — current | — | 28,558 |
| Total derivatives designated as hedges | | $ 2,630 | $ 28,828 |
| | | | |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $ 1,481 | $ — |
| Commodity derivatives | Derivative assets — non-current | 145 | — |
| Commodity derivatives | Derivative liabilities — current | — | 254 |
| Commodity derivatives | Derivative liabilities — non-current | — | 4 |
| Total derivatives not designated as hedges | | $ 1,626 | $ 258 |

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about the fair value measurements of their assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 18 to the Consolidated Financial Statements included in our 2016 Annual Report on Form 10-K.

## (12) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 11, were as follows (in thousands) as of:

| | June 30, 2017 | | December 31, 2016 | | June 30, 2016 | |
|---|---|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash and cash equivalents [(a)] | $11,590 | $11,590 | $13,580 | $13,580 | $61,859 | $61,859 |
| Restricted cash and equivalents [(a)] | $2,534 | $2,534 | $2,274 | $2,274 | $1,975 | $1,975 |
| Notes payable [(b)] | $107,975 | $107,975 | $96,600 | $96,600 | $75,000 | $75,000 |
| Long-term debt, including current maturities, net of deferred financing costs [(c)] | $3,166,045 | $3,377,891 | $3,216,932 | $3,351,305 | $3,152,090 | $3,427,587 |

(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) Notes payable consist of commercial paper borrowings and borrowings on our Revolving Credit Facility. Carrying value approximates fair value due to the short-term length of maturity; since these borrowings are not traded on an exchange, they are classified in Level 2 in the fair value hierarchy.

(c) 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.

## (13) OTHER COMPREHENSIVE INCOME (LOSS)

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges, commodity contracts designated as cash flow hedges and the amortization of components of our defined benefit plans. Deferred gains (losses) for our commodity contracts designated as cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate swaps are recognized in earnings as they are amortized.

The following table details reclassifications out of AOCI and into net income. The amounts in parentheses below indicate decreases to net income in the Consolidated Statements of Income for the period, net of tax (in thousands):

| | | Amount Reclassified from AOCI | | | |
|---|---|---|---|---|---|
| | Location on the Condensed Consolidated Statements of Income | Three months ended | | Six Months Ended | |
| | | June 30, 2017 | June 30, 2016 | June 30, 2017 | June 30, 2016 |
| Gains and (losses) on cash flow hedges: | | | | | |
| Interest rate swaps | Interest expense | $(713) | $(840) | $(1,515) | $(1,690) |
| Commodity contracts | Revenue | 430 | 3,287 | 659 | 6,939 |
| Commodity contracts | Fuel, purchased power and cost of natural gas sold | (44) | (61) | 14 | (151) |
| | | (327) | 2,386 | (842) | 5,098 |
| Income tax | Income tax benefit (expense) | 106 | (882) | 281 | (1,884) |
| Total reclassification adjustments related to cash flow hedges, net of tax | | $(221) | $1,504 | $(561) | $3,214 |
| | | | | | |
| Amortization of components of defined benefit plans: | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Prior service cost | Operations and maintenance | $49 | $55 | $97 | $110 |
| Actuarial gain (loss) | Operations and maintenance | (414 ) | (494 ) | (828 ) | (989 ) |
| | | (365 ) | (439 ) | (731 ) | (879 ) |
| Income tax | Income tax benefit (expense) | 128 | 154 | 265 | 308 |
| Total reclassification adjustments related to defined benefit plans, net of tax | | $(237) | $(285 ) | $(466 ) | $(571 ) |
| Total reclassifications | | $(458) | $1,219 | $(1,027) | $2,643 |

Balances by classification included within AOCI, net of tax on the accompanying Condensed Consolidated Balance Sheets were as follows (in thousands):

| | Derivatives Designated as Cash Flow Hedges | | | |
|---|---|---|---|---|
| | Interest Rate Swaps | Commodity Derivatives | Employee Benefit Plans | Total |
| As of December 31, 2016 | $(18,109) | $ (233) | $(16,541) | $(34,883) |
| Other comprehensive income (loss) before reclassifications | — | 915 | — | 915 |
| Amounts reclassified from AOCI | 985 | (424) | 466 | 1,027 |
| Ending Balance June 30, 2017 | $(17,124) | $ 258 | $(16,075) | $(32,941) |

| | Derivatives Designated as Cash Flow Hedges | | | |
|---|---|---|---|---|
| | Interest Rate Swaps | Commodity Derivatives | Employee Benefit Plans | Total |
| Balance as of December 31, 2015 | $(341) | $ 7,066 | $(15,780) | $(9,055) |
| Other comprehensive income (loss) before reclassifications | (19,898) | (168) | — | (20,066) |
| Amounts reclassified from AOCI | 1,098 | (4,312) | 571 | (2,643) |
| Ending Balance June 30, 2016 | $(19,141) | $ 2,586 | $(15,209) | $(31,764) |

## (14) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

| Six Months Ended | June 30, 2017 | June 30, 2016 |
|---|---|---|
| | (in thousands) | |
| Non-cash investing and financing activities— | | |
| Property, plant and equipment acquired with accrued liabilities | $37,601 | $52,917 |
| | | |
| Cash (paid) refunded during the period — | | |
| Interest (net of amounts capitalized) | $(65,820) | $(48,139) |
| Income taxes, net | $1 | $(1,162) |

(15) 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, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Service cost | $1,759 | $2,078 | $3,517 | $4,156 |
| Interest cost | 3,880 | 3,936 | 7,760 | 7,872 |
| Expected return on plan assets | (6,129 ) | (5,766 ) | (12,258) | (11,531) |
| Prior service cost | 15 | 15 | 29 | 30 |
| Net loss (gain) | 1,001 | 1,793 | 2,003 | 3,586 |
| Net periodic benefit cost | $526 | $2,056 | $1,051 | $4,113 |

Defined Benefit Postretirement Healthcare Plans

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Service cost | $575 | $467 | $1,150 | $934 |
| Interest cost | 534 | 485 | 1,067 | 970 |
| Expected return on plan assets | (79 ) | (70 ) | (158 ) | (140 ) |
| Prior service cost (benefit) | (109 ) | (107 ) | (218 ) | (214 ) |
| Net loss (gain) | 125 | 84 | 250 | 168 |
| Net periodic benefit cost | $1,046 | $859 | $2,091 | $1,718 |

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, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Service cost | $609 | $878 | $1,436 | $907 |
| Interest cost | 319 | 315 | 638 | 629 |
| Prior service cost | — | 1 | 1 | 1 |
| Net loss (gain) | 250 | 207 | 500 | 414 |
| Net periodic benefit cost | $1,178 | $1,401 | $2,575 | $1,951 |

Contributions

Contributions to the Defined Benefit Pension Plan are cash contributions made directly to the Pension Plan Trust accounts. On July 24, 2017, we made contributions to the Defined Benefit Pension Plan in the amount of approximately $13 million. Contributions to the Healthcare and Supplemental Plans are made in the form of benefit payments. Contributions made in 2017 and anticipated contributions for 2017 and 2018 are as follows (in thousands):

| | Contributions Made | Contributions Made | Additional Contributions | Contributions |
|---|---|---|---|---|
| | Three Months Ended June 30, 2017 | Six Months Ended June 30, 2017 | Anticipated for 2017 | Anticipated for 2018 |
| Defined Benefit Pension Plan | $ — | $ — | $ 12,700 | $ 12,700 |
| Non-pension Defined Benefit Postretirement Healthcare Plans | $ 1,270 | $ 2,540 | $ 2,540 | $ 5,115 |
| Supplemental Non-qualified Defined Benefit and Defined Contribution Plans | $ 396 | $ 792 | $ 792 | $ 1,682 |

(16) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K except for those described below.

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, 2017, we were in compliance with the debt 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.

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 and financing agreements. As of June 30, 2017, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

(17) IMPAIRMENT OF ASSETS

Long-lived Assets

Our Oil and Gas segment accounts for oil and gas activities under the full cost method of accounting. Under the full cost method, all productive and non-productive costs related to acquisition, exploration, development, abandonment and reclamation activities are capitalized. These capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC plus the lower of cost or market value of unevaluated properties. Any costs in excess of the ceiling are written off as a non-cash charge.

There were no impairments for the six months ended June 30, 2017. In determining the ceiling value of our assets under the full cost accounting rules of the SEC, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. At June 30, 2017, the average NYMEX natural gas price was $3.01 per Mcf, adjusted to $2.70 per Mcf at the wellhead; the average NYMEX crude oil price was $48.95 per barrel, adjusted to $44.42 per barrel at the wellhead. At June 30, 2016, the average NYMEX natural gas price was $2.24 per Mcf, adjusted to $1.01 per Mcf at the wellhead; the average NYMEX crude oil price was $43.12 per barrel, adjusted to $37.19 per barrel at the wellhead. During the three and six months ended June 30, 2016, we recorded pre-tax non-cash impairments of oil and gas assets included in our Oil and Gas segment of $11 million and $25 million, respectively.

During the second quarter of 2016, in advancing our Oil and Gas strategy, certain non-core assets were identified that are not suitable for inclusion in a possible Cost of Service Gas program. We assessed these assets for impairment in accordance with ASC 360. We valued the assets applying a market method approach utilizing assumptions consistent with similar known and measurable transactions and determined that the carrying amount exceeded the fair value. As a result, we recorded a pre-tax impairment of depreciable properties at June 30, 2016 of $14 million, in addition to the impairments noted above.

(18) INCOME TAXES

The effective tax rate differs from the federal statutory rate as follows:

| | Three Months Ended June 30, | |
|---|---|---|
| Tax (benefit) expense | 2017 | 2016 |
| Federal statutory rate | 35.0 % | 35.0 % |
| State income tax (net of federal tax effect) [(a)] | (0.1 ) | 16.9 |
| Percentage depletion in excess of cost | (1.2 ) | (5.9 ) |
| Accounting for uncertain tax positions adjustment | — | 1.9 |
| Noncontrolling interest [(b)] | (3.1 ) | (25.1) |
| Tax credits [(c)] | (3.6 ) | — |
| Effective tax rate adjustment [(d)] | 4.4 | 1.7 |
| Flow-through adjustments [(e)] | (2.6 ) | (10.6) |
| AFUDC equity [(f)] | (0.6 ) | (5.8 ) |
| Other tax differences | 0.9 | 0.5 |
| | 29.1 % | 8.6 % |

__________

(a) In the three months ending June 30, 2017, the state income tax benefit is primarily attributable to favorable flow-through adjustments and a pretax net loss at state tax accruing companies.

(b) The adjustment reflects the noncontrolling interest attributable to the sale of 49.9% of the membership interests of Colorado IPP in April 2016.

(c) The increase in tax credits is due to Peak View Wind Project production tax credits and the marginal gas well tax credit on the oil and gas segment.

(d) Adjustment to reflect the projected annual effective tax rate, pursuant to ASC 740-270.

(e) In the three months ending June 30, 2016, the increase in flow-through was primarily attributable to the Section 263A change of accounting method 481(a) adjustment. This change resulted in a basis difference whose tax benefit is flowed through versus being normalized as federal tax depreciation.

(f) In the three months ending June 30, 2016, AFUDC equity benefit increased primarily due to the Peak View Wind Project.

The lower pre-tax income for the second quarter of 2016 caused some of the percentages to not be reflective of the expected impact on full year operating results.

| | Six Months Ended June 30, | |
|---|---|---|
| Tax (benefit) expense | 2017 | 2016 |
| Federal statutory rate | 35.0 % | 35.0 % |
| State income tax (net of federal tax effect) [(a)] | 1.0 | 3.8 |
| Percentage depletion in excess of cost [(b)] | (0.6 ) | (13.5) |
| Accounting for uncertain tax positions adjustment [(c)] | — | (10.4) |
| Noncontrolling interest [(d)] | (1.6 ) | (1.9 ) |
| IRC 172(f) carryback claim [(e)] | (1.3 ) | — |
| Tax credits [(f)] | (1.8 ) | — |
| Effective tax rate adjustment [(g)] | (0.8 ) | (3.5 ) |
| Flow-through adjustments [(h)] | (1.0 ) | (1.7 ) |
| Transaction costs | — | 2.3 |
| Other tax differences | 0.4 | (0.6 ) |
| | 29.3 % | 9.5 % |

(a) The state income tax expense is lower primarily attributable to favorable flow-through adjustments.

(b) The tax benefit for the six months ended June 30, 2016 relates to additional percentage depletion deductions that are being claimed with respect to the oil and gas properties involving prior tax years. Such deductions are primarily the result of a change in the application of the maximum daily limitation of 1,000 barrels of oil equivalent as allowed under the Internal Revenue Code.

(c) The tax benefit for the six months ended June 30, 2016 relates to the release of after-tax interest expense that was previously accrued with respect to the liability for uncertain tax positions involving the like-kind exchange transaction effectuated in connection with the IPP Transaction and Aquila Transaction that occurred in 2008. In addition, the tax benefit includes the release of reserves involving research and development credits and deductions. Both adjustments are the result of a re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016.

(d) Black Hills Colorado IPP went from a single member LLC, wholly-owned by Black Hills Electric Generation, to a partnership as a result of the sale of 49.9% of its membership interest in April 2016. The effective tax rate reflects the income attributable to the noncontrolling interest for which a tax provision is not recorded.

(e) In Q1 2017, the Company filed amended income tax returns for the years 2006 through 2008 to carryback specified liability losses in accordance with IRC172(f). As a result of filing the amended returns, the Company's accrued tax liability interest decreased, certain valuation allowances increased and the previously recorded domestic production activities deduction decreased.

(f) The tax credits for the six months ended June 30, 2017 are the result of Colorado Electric placing the Peak View Wind Project into service in November 2016. The Peak View Wind Project began generating production tax credits during the fourth quarter of 2016.

(g) Adjustment to reflect our 2017 and 2016 annual projected effective tax rate, pursuant to ASC 740-270.

(h) The flow-through adjustments related primarily to an accounting method change for tax purpose that allows us to take a current tax deduction for repair costs that continue to be capitalized for book purposes. In addition, flow-through adjustments were recorded related to an accounting method change for tax purposes that allows us to take a current tax deduction for certain indirect costs that continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to tax expense. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record tax benefits consistent with the flow-through method.

In the first quarter of 2016, we reached an agreement in principle with IRS Appeals in regards to the like-kind exchange transaction associated with the gain deferred from the tax treatment related to the 2008 IPP Transaction and the Aquila Transaction. An agreement in principle was also reached with respect to research and development credits and deductions. Both issues were the subject of an IRS Appeals process involving the 2007 to 2009 tax years. We reversed approximately $35 million of the liability for unrecognized tax benefits, including interest, during the first quarter of 2016. The vast majority of such reversal was to restore accumulated deferred income taxes. We reversed accrued after-tax interest expense and tax credits of approximately $5.1 million associated with these liabilities in the first quarter of 2016. The cash taxes due as a result of the agreement in principle with IRS Appeals is estimated to be $8.0 million excluding interest.

(19) ACCRUED LIABILITIES

The following amounts by major classification are included in Accrued liabilities in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

| | June 30, 2017 | December 31, 2016 | June 30, 2016 |
|---|---|---|---|
| Accrued employee compensation, benefits and withholdings | $45,767 | $56,926 | $45,991 |
| Accrued property taxes | 34,683 | 40,004 | 33,295 |
| Customer deposits and prepayments | 41,067 | 51,628 | 44,200 |
| Accrued interest and contract adjustment payments | 33,914 | 45,503 | 42,330 |
| CIAC current portion | 1,575 | — | 20,211 |
| Other (none of which is individually significant) | 44,987 | 49,973 | 32,223 |
| Total accrued liabilities | $201,993 | $244,034 | $218,250 |

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

We are a customer-focused, growth-oriented utility company operating in the United States. We report our operations and results in the following financial segments:

Electric Utilities: Our Electric Utilities segment generates, transmits and distributes electricity to approximately 208,500 customers in South Dakota, Wyoming, Colorado and Montana. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates.

Gas Utilities: Our Gas Utilities conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming subsidiaries. Our Gas Utilities distribute and transport natural gas through our pipeline network to approximately 1,030,800 natural gas customers. Additionally, we sell temporarily-available, contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates.

We also provide non-regulated services through Black Hills Energy Services. Black Hills Energy Services provides approximately 55,000 retail distribution customers in Nebraska and Wyoming with unbundled natural gas commodity offerings under the regulatory-approved Choice Gas Program. We also sell, install and service air, heating and water-heating equipment, and provide associated repair service and protection plans under various trade names. Service Guard and CAPP primarily provide appliance repair services to approximately 61,000 and 33,000 residential customers, respectively, through Company technicians and third-party service providers, typically through on-going monthly service agreements. Tech Services primarily serves gas transportation customers throughout our service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.

Power Generation: Our Power Generation segment produces electric power from its generating plants and sells the electric capacity and energy principally to our utilities under long-term contracts.

Mining: Our Mining segment produces coal at our coal mine near Gillette, Wyoming and sells the coal primarily to on-site, mine-mouth power generation facilities.

Oil and Gas: Our Oil and Gas segment engages in the production of crude oil and natural gas, primarily in the Rocky Mountain region. We are divesting non-core oil and gas assets while retaining those best suited for a possible future cost of service gas program and we have refocused our professional staff on assisting our utilities with the implementation of a cost of service gas program.

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 our electric utilities is June through August while the normal peak usage season for our 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, 2017 and 2016, and our financial condition as of June 30, 2017, December 31, 2016 and June 30, 2016, 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 73.

The 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, 2017 Compared to Three Months Ended June 30, 2016. Net income (loss) available for common stock for the three months ended June 30, 2017 was $22 million, or $0.40 per share, compared to Net income (loss) available for common stock of $0.7 million, or $0.01 per share, reported for the same period in 2016. The Net income (loss) available for common stock for the three months ended June 30, 2017 increased over the same period in the prior year primarily due to a decrease in after-tax impairment charges of approximately $16 million on our oil and gas properties, lower after-tax corporate expenses of approximately $4.1 million primarily due to acquisition and transition costs incurred in the prior year, and higher earnings of $2.0 million at our Mining segment resulting from an increase in tons sold driven by a prior year outage. These are partially offset by lower earnings of $1.3 million at our Gas Utilities.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. Net income (loss) available for common stock for the six months ended June 30, 2017 was $99 million, or $1.79 per share, compared to Net income (loss) available for common stock of $41 million, or $0.78 per share, reported for the same period in 2016. The Net income (loss) available for common stock for the six months ended June 30, 2017 increased over the same period in the prior year primarily due to higher earnings at our Gas Utilities, Electric Utilities and Mining segments, lower corporate expenses, and a decrease in impairment charges on our oil and gas properties, partially offset by lower earnings at our Power Generation segment and by tax benefits realized during the same period in the prior year.

Net income (loss) available for common stock for the six months ended June 30, 2017 included a $13 million increase in our Gas Utilities' earnings with a full six months of earnings from our acquired SourceGas utilities compared to approximately 4.5 months in the same period of the prior year. Corporate expenses decreased by a total of $22 million after-tax compared to the same period in the prior year driven primarily by a $19 million after-tax reduction of acquisition and transition costs. Our Electric Utilities' earnings increased approximately $2.6 million driven primarily by returns on prior year generation investments. Earnings at our Mining segment increased $1.9 million due to an increase in tons sold as a result of an extended outage in the prior year. The Net income (loss) available for common stock for the six months ended June 30, 2017 is net of $6.7 million of net income attributable to noncontrolling interests compared to $2.7 million in the same period of the prior year. We recognized a $1.4 million tax benefit from a carryback claim during the six months ended June 30, 2017 compared to the same period in the prior year. The prior year included approximately $11 million in tax benefits recognized from additional percentage depletion deductions claimed with respect to our oil and gas properties and the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016. The six months ended June 30, 2016 also included non-cash after-tax impairments on our oil and gas properties of $25 million.

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, | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | Variance | 2017 | 2016 | Variance |
| Revenue | | | | | | |
| Revenue | $377,790 | $353,849 | $23,941 | $965,312 | $839,563 | $125,749 |
| Inter-company eliminations | (29,812) | (28,408) | (1,404) | (63,331) | (64,163) | 832 |
| | $347,978 | $325,441 | $22,537 | $901,981 | $775,400 | $126,581 |
| Net income (loss) available for common stock | | | | | | |
| Electric Utilities | $18,832 | $19,229 | $(397) | $41,062 | $38,444 | $2,618 |
| Gas Utilities | (272) | 987 | (1,259) | 45,738 | 32,914 | 12,824 |
| Power Generation [(a)] | 5,332 | 5,683 | (351) | 11,862 | 14,265 | (2,403) |
| Mining | 2,681 | 724 | 1,957 | 5,571 | 3,662 | 1,909 |
| Oil and Gas [(b)] [(c)] | (1,946) | (19,424) | 17,478 | (4,897) | (26,448) | 21,551 |
| | 24,627 | 7,199 | 17,428 | 99,336 | 62,837 | 36,499 |
| Corporate activities and eliminations [(d)] [(e)] | (2,432) | (6,530) | 4,098 | (618) | (22,166) | 21,548 |
| Net income (loss) available for common stock | $22,195 | $669 | $21,526 | $98,718 | $40,671 | $58,047 |

(a) Net income (loss) available for common stock for the three and six months ended June 30, 2017 is net of net income attributable to noncontrolling interest of $3.1 million and $6.6 million, respectively, and $2.6 million for both the three and six months ended June 30, 2016.

(b) Net income (loss) available for common stock for the three and six months ended June 30, 2016 included non-cash after-tax impairments of our oil and gas properties of $16 million and $25 million. See Note 17 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(c) Net income (loss) available for common stock for the six months ended June 30, 2016 included a tax benefit of approximately $5.8 million recognized from additional percentage depletion deductions that are being claimed with respect to our oil and gas properties involving prior tax years.

(d) Net income (loss) available for common stock for the three and six months ended June 30, 2017 included incremental, non-recurring acquisition costs, after-tax of $0.3 million and $1.2 million, respectively, as compared to $4.1 million and $20 million for the same periods in the prior year. The three and six months ended June 30, 2016 also included after-tax internal labor costs attributable to the acquisition of $2.0 million and $5.7 million, respectively.

(e) Net income (loss) available for common stock for the six months ended June 30, 2017 included a net tax benefit of approximately $1.4 million from a carryback claim for specified liability losses involving prior tax years. Net income (loss) available for common stock for the six months ended June 30, 2016 included tax benefits of approximately $4.4 million as a result of the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016. See Note 18 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Overview of Business Segments and Corporate Activity

Electric Utilities Segment

- Electric Utilities experienced milder weather during the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016. Cooling degree days for the three and six months ended June 30, 2017 were 14% higher than normal compared to 68% higher than normal for the same periods in 2016. Compared to the same periods in the prior year, cooling degree days were 38% lower. Heating degree days for the three and six months ended June 30, 2017 were 9% and 11% lower than normal, respectively, compared to 14% and 13% lower than normal for the same periods in 2016.

- On January 17, 2017, Colorado Electric received approval from the CPUC for a settlement agreement of its electric resource plan which provides for the addition of 60 megawatts of renewable energy to be in service by 2019. The resource plan was filed June 3, 2016, to meet requirements under the Colorado Renewable Energy Standard. In the second quarter of 2017, Colorado Electric issued a request for proposals to construct new generation and plans to present the results to the CPUC by year-end.

- On January 9, 2017, we filed an application with the CPUC for rehearing, reargument or reconsideration of the Commission's December 19, 2016 decision to increase annual revenue by $1.2 million. This application was denied by the CPUC on June 9, 2017. We subsequently filed an appeal of this decision with Denver District Court on July 10, 2017.

- Construction was completed on the 144 mile-long transmission line connecting the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange was placed in service on May 30, 2017.

- On July 19, 2017, Wyoming Electric set a new summer load peak of 249 MW, exceeding the previous summer peak of 236 MW set in July 2016.

Gas Utilities Segment

- Gas Utilities experienced slightly colder weather during the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016. Heating degree days for the three and six months ended June 30, 2017 were 9% and 12% lower than normal, respectively, compared to 17% and 20% lower than normal for the same periods in 2016.

Oil and Gas Segment

- Oil and Gas production volumes decreased 23% and 22% for the three and six months ended June 30, 2017 compared to the same periods in 2016, respectively. The decrease in production was due to the 2016 sales of non-core properties, and limiting natural gas production to meet minimum daily quantity contractual gas processing commitments in the Piceance. Crude oil production also decreased due to non-core property sales in the fourth quarter of 2016. The average hedged price received for natural gas increased 68% and 48% for the three and six months ended June 30, 2017 compared to the same periods in 2016, respectively. The average hedged price received for oil decreased 25% and 15% for the three and six months ended June 30, 2017 compared to the same periods in 2016, respectively.

Corporate Activities

- We utilized favorable short-term borrowings from our CP program to pay down $100 million on a Corporate term loan due in 2019 with principal payments of $50 million paid in May and an additional $50 million paid in July.

- On July 21, 2017, S&P affirmed Black Hills' credit rating at BBB rating and maintained a Stable outlook.

- On March 29, 2017, Fitch affirmed Black Hills' credit rating at BBB+ rating and changed its outlook from Negative to Stable, citing successful integration of SourceGas, a low business risk profile focused on utility operations and expected improvement of credit metrics.

Operating Results

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

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 and purchased power. Gross margin for our Gas Utilities is calculated as operating revenue 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, | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | Variance | 2017 | 2016 | Variance |
| | (in thousands) | | | | | |
| Revenue | $168,453 | $161,481 | $6,972 | $344,477 | $328,757 | $15,720 |
| Total fuel and purchased power | 62,265 | 61,418 | 847 | 130,665 | 127,524 | 3,141 |
| Gross margin | 106,188 | 100,063 | 6,125 | 213,812 | 201,233 | 12,579 |
| Operations and maintenance | 44,315 | 38,879 | 5,436 | 85,098 | 78,204 | 6,894 |
| Depreciation and amortization | 23,120 | 20,473 | 2,647 | 45,981 | 41,731 | 4,250 |
| Total operating expenses | 67,435 | 59,352 | 8,083 | 131,079 | 119,935 | 11,144 |
| Operating income | 38,753 | 40,711 | (1,958) | 82,733 | 81,298 | 1,435 |
| Interest expense, net | (12,893) | (12,131) | (762) | (26,305) | (24,630) | (1,675) |
| Other income (expense), net | 590 | 838 | (248) | 930 | 1,493 | (563) |
| Income tax benefit (expense) | (7,618) | (10,189) | 2,571 | (16,296) | (19,717) | 3,421 |
| Net income | $18,832 | $19,229 | $(397) | $41,062 | $38,444 | $2,618 |

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Results of Operations for the Electric Utilities for the Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016: Net income available for common stock for the Electric Utilities was $19 million for the three months ended June 30, 2017, compared to Net income available for common stock of $19 million for the three months ended June 30, 2016, as a result of:

Gross margin increased due to a $2.3 million return on investment from the Peak View Wind Project, a $1.9 million increase in commercial and industrial margins driven by increased demand largely associated with data centers in Cheyenne, Wyoming, a $1.6 million increase due to prior year billing true-ups, and a $1.5 million increase in rider revenues primarily related to transmission investment recovery. Partially offsetting these increases was $1.2 million in lower residential margins driven primarily by lower cooling degree days as compared to prior year. Cooling degree days were 14 percent higher than normal in the current year as compared to 68 percent higher than normal for the same period in the prior year.

Operations and maintenance increased primarily due to $1.7 million of higher employee costs as a result of prior year integration activities and transition expenses charged to the Corporate segment. Generation outage-related expenses increased by $1.3 million due to the timing of current year outages compared to the prior year and operating expenses increased $0.5 million from the addition of the Peak View Wind Project and the 40-megawatt gas turbine at the Pueblo Airport Generating Station. Property taxes associated with increased asset base increased $0.7 million. A variety of smaller items contributed to the remainder of the increase.

Depreciation and amortization increased primarily due to a higher asset base driven by the addition of the Peak View Wind Project and the 40-megawatt gas turbine at the Pueblo Airport Generating Station.

Interest expense, net increased primarily due to higher intercompany debt resulting from additional investments as compared to prior year.

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

Income tax benefit (expense): The effective tax rate was lower than the prior year due primarily to wind production tax credits related to the Peak View Wind Project.

Results of Operations for the Electric Utilities for the Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016: Net income available for common stock for the Electric Utilities was $41 million for the six months ended June 30, 2017, compared to Net income available for common stock of $38 million for the six months ended June 30, 2016, as a result of:

Gross margin increased over the prior year reflecting a $4.5 million return on investment from the Peak View Wind Project, a $3.7 million increase in commercial and industrial margins driven by increased demand largely associated with data centers in Cheyenne, Wyoming, a $2.9 million increase in rider revenues primarily related to transmission investment recovery, and a $1.5 million increase due to a prior year billing true-up.

Operations and maintenance increased primarily due to $4.6 million of higher employee costs as a result of prior year integration activities and transition expenses charged to the Corporate segment, $1.4 million of higher property taxes with increased asset base, and $1.0 million of higher operating expenses from the Peak View Wind Project and Pueblo Airport Generating Station gas turbine additions.

Depreciation and amortization increased primarily due to a higher asset base driven by the addition of the Peak View Wind Project and the 40-megawatt gas turbine at the Pueblo Airport Generating Station.

Interest expense, net increased primarily due to higher intercompany debt resulting from additional investments as compared to prior year.

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

Income tax benefit (expense): The effective tax rate was lower than the prior year due primarily to wind production tax credits related to the Peak View Wind Project.

| Revenue - Electric (in thousands) | Three Months Ended June 30, 2017 | 2016 | Six Months Ended June 30, 2017 | 2016 |
|---|---|---|---|---|
| Residential: | | | | |
| South Dakota Electric | $15,633 | $16,241 | $35,704 | $35,556 |
| Wyoming Electric | 9,077 | 9,241 | 19,488 | 19,698 |
| Colorado Electric | 23,223 | 23,148 | 46,959 | 46,261 |
| Total Residential | 47,933 | 48,630 | 102,151 | 101,515 |
| | | | | |
| Commercial: | | | | |
| South Dakota Electric | 22,858 | 23,723 | 47,149 | 47,312 |
| Wyoming Electric | 16,205 | 15,839 | 32,176 | 31,512 |
| Colorado Electric | 24,875 | 24,392 | 48,126 | 46,875 |
| Total Commercial | 63,938 | 63,954 | 127,451 | 125,699 |
| | | | | |
| Industrial: | | | | |
| South Dakota Electric | 8,171 | 7,764 | 16,625 | 16,265 |
| Wyoming Electric | 12,831 | 10,352 | 25,633 | 20,449 |
| Colorado Electric | 9,734 | 9,782 | 18,761 | 19,047 |
| Total Industrial | 30,736 | 27,898 | 61,019 | 55,761 |
| | | | | |
| Municipal: | | | | |
| South Dakota Electric | 942 | 960 | 1,778 | 1,791 |
| Wyoming Electric | 543 | 552 | 1,046 | 1,063 |
| Colorado Electric | 3,191 | 2,885 | 6,152 | 5,580 |
| Total Municipal | 4,676 | 4,397 | 8,976 | 8,434 |
| | | | | |
| Total Retail Revenue - Electric | 147,283 | 144,879 | 299,597 | 291,409 |
| | | | | |
| Contract Wholesale: | | | | |
| Total Contract Wholesale - South Dakota Electric [a] | 6,702 | 3,947 | 14,545 | 8,121 |
| | | | | |
| Off-system Wholesale: | | | | |
| South Dakota Electric | 2,424 | 2,734 | 6,257 | 7,320 |
| Wyoming Electric | 1,081 | 1,007 | 2,747 | 2,853 |
| Colorado Electric | 163 | 573 | 174 | 707 |
| Total Off-system Wholesale | 3,668 | 4,314 | 9,178 | 10,880 |
| | | | | |
| Other Revenue: | | | | |
| South Dakota Electric | 9,322 | 6,650 | 17,788 | 14,296 |
| Wyoming Electric | 614 | 520 | 1,539 | 1,110 |
| Colorado Electric | 864 | 1,171 | 1,830 | 2,941 |
| Total Other Revenue | 10,800 | 8,341 | 21,157 | 18,347 |
| | | | | |
| Total Revenue - Electric | $168,453 | $161,481 | $344,477 | $328,757 |

(a) Increase for the three and six months ended June 30, 2017 was primarily due to a new 50 MW power sales agreement with Cargill effective January 1, 2017.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| Quantities Generated and Purchased (in MWh) | 2017 | 2016 | 2017 | 2016 |
| Generated — | | | | |
| Coal-fired: | | | | |
| South Dakota Electric | 289,540 | 265,032 | 677,525 | 653,033 |
| Wyoming Electric | 176,725 | 180,081 | 360,820 | 359,774 |
| Total Coal-fired | 466,265 | 445,113 | 1,038,345 | 1,012,807 |
| | | | | |
| Natural Gas and Oil: | | | | |
| South Dakota Electric [(a)] | 11,024 | 39,433 | 21,374 | 54,995 |
| Wyoming Electric [(a)] | 7,292 | 27,191 | 13,569 | 35,070 |
| Colorado Electric | 45,755 | 61,123 | 57,657 | 63,890 |
| Total Natural Gas and Oil | 64,071 | 127,747 | 92,600 | 153,955 |
| | | | | |
| Wind: | | | | |
| Colorado Electric [(b)] | 58,113 | 10,588 | 128,656 | 23,649 |
| Total Wind | 58,113 | 10,588 | 128,656 | 23,649 |
| | | | | |
| Total Generated: | | | | |
| South Dakota Electric | 300,564 | 304,465 | 698,899 | 708,028 |
| Wyoming Electric [(a)] | 184,017 | 207,272 | 374,389 | 394,844 |
| Colorado Electric [(b)] | 103,868 | 71,711 | 186,313 | 87,539 |
| Total Generated | 588,449 | 583,448 | 1,259,601 | 1,190,411 |
| | | | | |
| Purchased — | | | | |
| South Dakota Electric [(c)] | 418,314 | 315,379 | 865,811 | 655,069 |
| Wyoming Electric [(d)] | 239,140 | 186,085 | 488,675 | 408,880 |
| Colorado Electric [(b)] | 394,614 | 467,365 | 797,041 | 945,248 |
| Total Purchased | 1,052,068 | 968,829 | 2,151,527 | 2,009,197 |
| | | | | |
| Total Generated and Purchased: | | | | |
| South Dakota Electric [(c)] | 718,878 | 619,844 | 1,564,710 | 1,363,097 |
| Wyoming Electric | 423,157 | 393,357 | 863,064 | 803,724 |
| Colorado Electric | 498,482 | 539,076 | 983,354 | 1,032,787 |
| Total Generated and Purchased | 1,640,517 | 1,552,277 | 3,411,128 | 3,199,608 |

(a) Decrease is primarily due to the ability to purchase excess generation in the open market at a lower cost than to generate for the three and six months ended June 30, 2017.

(b) Increase in 2017 is due to the addition of the Peak View Wind Project in November 2016. This generation replaced resources provided by PPAs in 2016.

(c) Increase in 2017 is primarily driven by resource needs from a new 50MW power sales agreement with Cargill effective January 1, 2017.

(d) Year over year increases are primarily driven by new load supporting data centers in Cheyenne, Wyoming.

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| Quantity Sold (in MWh) | Three Months Ended June 30, 2017 | 2016 | Six Months Ended June 30, 2017 | 2016 |
|---|---|---|---|---|
| Residential: | | | | |
| South Dakota Electric | 107,521 | 114,851 | 257,093 | 257,604 |
| Wyoming Electric | 57,191 | 59,587 | 124,364 | 127,900 |
| Colorado Electric | 142,154 | 144,318 | 287,514 | 293,346 |
| Total Residential | 306,866 | 318,756 | 668,971 | 678,850 |
| | | | | |
| Commercial: | | | | |
| South Dakota Electric | 173,720 | 190,207 | 370,126 | 379,095 |
| Wyoming Electric | 128,827 | 130,550 | 261,009 | 260,880 |
| Colorado Electric | 182,658 | 184,150 | 358,144 | 360,346 |
| Total Commercial | 485,205 | 504,907 | 989,279 | 1,000,321 |
| | | | | |
| Industrial: | | | | |
| South Dakota Electric | 103,497 | 102,620 | 213,293 | 210,641 |
| Wyoming Electric [(a)] | 184,809 | 150,332 | 362,796 | 293,074 |
| Colorado Electric | 106,490 | 113,454 | 209,281 | 212,943 |
| Total Industrial | 394,796 | 366,406 | 785,370 | 716,658 |
| | | | | |
| Municipal: | | | | |
| South Dakota Electric | 8,104 | 8,487 | 15,709 | 15,928 |
| Wyoming Electric | 2,006 | 2,102 | 4,489 | 4,647 |
| Colorado Electric | 30,594 | 30,026 | 57,478 | 56,609 |
| Total Municipal | 40,704 | 40,615 | 77,676 | 77,184 |
| | | | | |
| Total Retail Quantity Sold | 1,227,571 | 1,230,684 | 2,521,296 | 2,473,013 |
| | | | | |
| Contract Wholesale: | | | | |
| Total Contract Wholesale-South Dakota Electric [(b)] | 165,881 | 56,087 | 351,997 | 119,540 |
| | | | | |
| Off-system Wholesale: | | | | |
| South Dakota Electric [(c)] | 102,966 | 117,064 | 257,462 | 310,437 |
| Wyoming Electric | 22,183 | 21,253 | 54,536 | 58,746 |
| Colorado Electric [(c)] | 5,274 | 28,233 | 5,860 | 35,695 |
| Total Off-system Wholesale | 130,423 | 166,550 | 317,858 | 404,878 |
| | | | | |
| Total Quantity Sold: | | | | |
| South Dakota Electric | 661,689 | 589,316 | 1,465,680 | 1,293,245 |
| Wyoming Electric | 395,016 | 363,824 | 807,194 | 745,247 |
| Colorado Electric | 467,170 | 500,181 | 918,277 | 958,939 |
| Total Quantity Sold | 1,523,875 | 1,453,321 | 3,191,151 | 2,997,431 |
| | | | | |
| Other Uses, Losses or Generation, net [(d)]: | | | | |
| South Dakota Electric | 57,189 | 30,528 | 99,030 | 69,852 |
| Wyoming Electric | 28,141 | 29,533 | 55,870 | 58,477 |
| Colorado Electric | 31,312 | 38,895 | 65,077 | 73,848 |

| | | | | |
|---|---|---|---|---|
| Total Other Uses, Losses and Generation, net | 116,642 | 98,956 | 219,977 | 202,177 |
| Total Energy | 1,640,517 | 1,552,277 | 3,411,128 | 3,199,608 |

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(a) Year over year increases are driven by new load supporting data centers in Cheyenne, Wyoming.

(b) Increase for the three and six months ended June 30, 2017 was primarily due to a new 50 MW power sales agreement with Cargill effective January 1, 2017.

(c) Decrease in 2017 generation was primarily driven by commodity prices that impacted power marketing sales.

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

| Degree Days | Three Months Ended June 30, 2017 | | | 2016 | |
|---|---|---|---|---|---|
| | Actual | Variance from 30-Year Average | Actual Variance to Prior Year | Actual | Variance from 30-Year Average |
| Heating Degree Days: | | | | | |
| South Dakota Electric | 910 | (11 )% | 4% | 877 | (13 )% |
| Wyoming Electric | 1,164 | (5 )% | 3% | 1,134 | (15 )% |
| Colorado Electric | 567 | (10 )% | 10% | 516 | (15 )% |
| Combined [(a)] | 804 | (9 )% | 6% | 762 | (14 )% |
| | | | | | |
| Cooling Degree Days: | | | | | |
| South Dakota Electric | 114 | 15 % | (39)% | 186 | 74 % |
| Wyoming Electric | 41 | (18 )% | (60)% | 102 | 100 % |
| Colorado Electric | 243 | 16 % | (34)% | 369 | 63 % |
| Combined [(a)] | 158 | 14 % | (38)% | 253 | 68 % |

| Degree Days | Six Months Ended June 30, 2017 | | | 2016 | |
|---|---|---|---|---|---|
| | Actual | Variance from 30-Year Average | Actual Variance to Prior Year | Actual | Variance from 30-Year Average |
| Heating Degree Days: | | | | | |
| South Dakota Electric | 4,040 | (5 )% | 10% | 3,683 | (13 )% |
| Wyoming Electric | 3,894 | (12 )% | —% | 3,910 | (12 )% |
| Colorado Electric | 2,686 | (17 )% | (4)% | 2,801 | (13 )% |
| Combined [(a)] | 3,391 | (11 )% | 2% | 3,323 | (13 )% |
| | | | | | |
| Cooling Degree Days: | | | | | |
| South Dakota Electric | 114 | 15 % | (39)% | 186 | 74 % |
| Wyoming Electric | 41 | (18 )% | (60)% | 102 | 100 % |
| Colorado Electric | 243 | 16 % | (34)% | 369 | 63 % |
| Combined [(a)] | 158 | 14 % | (38)% | 253 | 68 % |

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(a) Combined actuals are calculated based on the weighted average number of total customers by state.

| Electric Utilities Power Plant Availability | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Coal-fired plants [(a)] | 74.8% | 75.1% | 83.0% | 84.5% |
| Natural gas fired plants and Other plants | 94.5% | 97.6% | 96.5% | 96.2% |
| Wind [(b)] | 93.4% | 99.3% | 92.4% | 99.3% |
| Total availability | 88.0% | 89.5% | 91.8% | 92.0% |

| | | | | |
|---|---|---|---|---|
| Wind capacity factor | 35.8% | 33.6% | 39.7% | 37.5% |

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(a) Both years included outages. 2017 included planned outages at Neil Simpson II, Wyodak and Wygen II, and 2016 included a planned outage at Wygen III and an extended planned outage at Wyodak.

(b) 2017 is lower than the prior year primarily due to the addition of the Peak View Wind Project for which 2017 is the first year of commercial operation.

Gas Utilities

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | Variance | 2017 | 2016 | Variance |
| | (in thousands) | | | | | |
| Revenue: | | | | | | |
| Natural gas — regulated | $150,426 | $137,840 | $12,586 | $492,059 | $392,264 | $99,795 |
| Other — non-regulated services | 16,021 | 14,121 | 1,900 | 39,298 | 30,170 | 9,128 |
| Total revenue | 166,447 | 151,961 | 14,486 | 531,357 | 422,434 | 108,923 |
| | | | | | | |
| Cost of sales | | | | | | |
| Natural gas — regulated | 52,332 | 43,149 | 9,183 | 222,034 | 172,914 | 49,120 |
| Other — non-regulated services | 10,018 | 5,156 | 4,862 | 21,698 | 13,355 | 8,343 |
| Total cost of sales | 62,350 | 48,305 | 14,045 | 243,732 | 186,269 | 57,463 |
| | | | | | | |
| Gross margin | 104,097 | 103,656 | 441 | 287,625 | 236,165 | 51,460 |
| | | | | | | |
| Operations and maintenance | 64,956 | 62,237 | 2,719 | 135,715 | 114,924 | 20,791 |
| Depreciation and amortization | 20,924 | 19,931 | 993 | 41,721 | 35,903 | 5,818 |
| Total operating expenses | 85,880 | 82,168 | 3,712 | 177,436 | 150,827 | 26,609 |
| | | | | | | |
| Operating income (loss) | 18,217 | 21,488 | (3,271) | 110,189 | 85,338 | 24,851 |
| | | | | | | |
| Interest expense, net | (19,610) | (19,074) | (536) | (39,392) | (32,591) | (6,801) |
| Other income (expense), net | (225) | (261) | 36 | (48) | 390 | (438) |
| Income tax benefit (expense) | 1,346 | (1,184) | 2,530 | (24,904) | (20,193) | (4,711) |
| Net income (loss) | (272) | 969 | (1,241) | 45,845 | 32,944 | 12,901 |
| Net (income) loss attributable to noncontrolling interest | — | 18 | (18) | (107) | (30) | (77) |
| Net income (loss) available for common stock | $(272) | $987 | $(1,259) | $45,738 | $32,914 | $12,824 |

Results of Operations for the Gas Utilities for the Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016: Net loss available for common stock for the Gas Utilities was $(0.3) million for the three months ended June 30, 2017, compared to Net income available for common stock of $1.0 million for the three months ended June 30, 2016, as a result of:

Gross margin was comparable to the same period in the prior year with comparable heating degree days in an off-peak quarter.

Operations and maintenance increased primarily due to $2.3 million higher employee related expenses as a result of prior year integration activities and transition expenses charged to the Corporate segment.

Depreciation and amortization increased due to additional depreciation from the higher asset base.

Interest expense, net increased primarily due to refinancing from variable to fixed rate debt, partially off-set by reduced borrowings.

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

Income tax benefit (expense): The effective tax rate is different due to pretax loss in 2017 and pretax income in 2016.

Results of Operations for the Gas Utilities for the Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016: Net income available for common stock for the Gas Utilities was $46 million for the six months ended June 30, 2017, compared to Net income available for common stock of $33 million for the six months ended June 30, 2016, as a result of:

Gross margin increased primarily due to margins of approximately $51 million contributed by the SourceGas utilities reflecting a full six months of results in 2017 as compared to approximately 4.5 months in 2016.

Operations and maintenance increased primarily due to additional operating costs of approximately $19 million for the acquired SourceGas utilities, reflecting a full six months of results in 2017 as compared to approximately 4.5 months in 2016. This $19 million increase included approximately $2.9 million of prior year integration activities and transition expenses charged to the Corporate segment. In addition, employee related expenses increased by $2.9 million for the Black Hills legacy gas utilities as a result of prior year integration activities and transition expenses charged to the Corporate segment.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas utilities.

Interest expense, net increased primarily due to additional interest expense from the acquired SourceGas utilities.

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

Income tax benefit (expense): The effective tax rate was lower as compared to the same period in the prior year primarily due to greater flow through benefit.

| Revenue (in thousands) [a] | Three Months Ended June 30, 2017 | 2016 | Six Months Ended June 30, 2017 | 2016 |
|---|---|---|---|---|
| Residential: | | | | |
| Arkansas | $12,551 | $9,799 | $48,907 | $25,577 |
| Colorado | 20,659 | 21,361 | 67,440 | 53,141 |
| Nebraska [b] | 15,841 | 14,327 | 60,343 | 56,873 |
| Iowa | 13,991 | 12,787 | 50,304 | 47,634 |
| Kansas | 10,097 | 9,320 | 36,181 | 31,668 |
| Wyoming [b] | 8,112 | 7,652 | 23,428 | 18,768 |
| Total Residential | $81,251 | $75,246 | $286,603 | $233,661 |
| | | | | |
| Commercial: | | | | |
| Arkansas | $7,131 | $4,801 | $25,184 | $12,529 |
| Colorado | 8,127 | 7,939 | 25,074 | 18,136 |
| Nebraska | 3,671 | 3,256 | 17,573 | 16,339 |
| Iowa | 5,133 | 4,336 | 21,097 | 19,473 |
| Kansas | 3,107 | 2,090 | 12,023 | 10,260 |
| Wyoming | 3,885 | 3,477 | 11,839 | 9,180 |
| Total Commercial | $31,054 | $25,899 | $112,790 | $85,917 |
| | | | | |
| Industrial: | | | | |
| Arkansas | $1,361 | $771 | $3,581 | $1,608 |
| Colorado | 313 | 278 | 682 | 532 |
| Nebraska | 55 | 69 | 205 | 187 |
| Iowa | 228 | 250 | 1,039 | 825 |
| Kansas | 1,585 | 1,959 | 1,982 | 2,589 |
| Wyoming | 739 | 703 | 1,738 | 1,657 |
| Total Industrial | $4,281 | $4,030 | $9,227 | $7,398 |
| | | | | |
| Transportation: | | | | |
| Arkansas | $2,415 | $2,110 | $5,415 | $3,733 |
| Colorado | 819 | 860 | 2,202 | 1,765 |
| Nebraska [b] | 15,219 | 14,148 | 33,859 | 25,925 |
| Iowa | 1,119 | 1,080 | 2,590 | 2,555 |
| Kansas | 1,311 | 1,355 | 3,253 | 3,398 |
| Wyoming [b] | 5,431 | 5,505 | 14,462 | 10,137 |
| Total Transportation | $26,314 | $25,058 | $61,781 | $47,513 |

| Revenue (in thousands) (continued) | Three Months Ended June 30, 2017 | 2016 | Six Months Ended June 30, 2017 | 2016 |
|---|---|---|---|---|
| Transmission: | | | | |
| Arkansas | $450 | $12 | $1,212 | $25 |
| Colorado | 4,018 | 3,683 | 13,764 | 8,762 |
| Wyoming | 1,223 | 1,118 | 2,501 | 2,177 |
| Total Transmission | $5,691 | $4,813 | $17,477 | $10,964 |
| | | | | |
| Other Sales Revenue: | | | | |
| Arkansas | $76 | $520 | $662 | $1,289 |
| Colorado | 149 | 292 | 479 | 455 |
| Nebraska | 788 | 874 | 1,787 | 1,675 |
| Iowa | 152 | 213 | 261 | 313 |
| Kansas | 408 | 643 | 442 | 2,633 |
| Wyoming | 262 | 252 | 550 | 446 |
| Total Other Sales Revenue | $1,835 | $2,794 | $4,181 | $6,811 |
| | | | | |
| Total Regulated Revenue | $150,426 | $137,840 | $492,059 | $392,264 |
| | | | | |
| Non-regulated Services | 16,021 | 14,121 | 39,298 | 30,170 |
| | | | | |
| Total Revenue | $166,447 | $151,961 | $531,357 | $422,434 |

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(a) Certain prior year revenue classes have been revised to conform to current year presentation; total revenue did not change.

(b) Change in prior year due to reclassification of Residential Choice customers from Residential to Transportation class.

| Gross Margin (in thousands) [a] | Three Months Ended June 30, 2017 | 2016 | Six Months Ended June 30, 2017 | 2016 |
|---|---|---|---|---|
| Residential: | | | | |
| Arkansas | $8,642 | $7,752 | $31,086 | $17,381 |
| Colorado | 9,419 | 9,819 | 26,251 | 21,296 |
| Nebraska [b] | 10,313 | 9,936 | 29,050 | 28,420 |
| Iowa | 9,221 | 8,989 | 23,012 | 22,596 |
| Kansas | 6,557 | 6,444 | 17,998 | 16,529 |
| Wyoming [b] | 5,041 | 5,001 | 12,847 | 11,301 |
| Total Residential | $49,193 | $47,941 | $140,244 | $117,523 |
| | | | | |
| Commercial: | | | | |
| Arkansas | $3,578 | $3,012 | $13,149 | $7,044 |
| Colorado | 3,311 | 3,072 | 8,462 | 6,227 |
| Nebraska | 1,798 | 1,756 | 6,346 | 6,213 |
| Iowa | 2,203 | 2,168 | 6,574 | 6,457 |
| Kansas | 1,464 | 1,100 | 4,475 | 4,011 |
| Wyoming | 1,681 | 1,715 | 4,828 | 4,379 |

| | | | | |
|---|---|---|---|---|
| Total Commercial | $14,035 | $12,823 | $43,834 | $34,331 |

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| Gross Margin (in thousands) (continued) | Three Months Ended June 30, 2017 | 2016 | Six Months Ended June 30, 2017 | 2016 |
|---|---|---|---|---|
| Industrial: | | | | |
| Arkansas | $311 | $368 | $1,161 | $686 |
| Colorado | 108 | 148 | 221 | 268 |
| Nebraska | 25 | 50 | 77 | 95 |
| Iowa | 46 | 44 | 136 | 87 |
| Kansas | 379 | 539 | 586 | 768 |
| Wyoming | 157 | 147 | 327 | 350 |
| Total Industrial | $1,026 | $1,296 | $2,508 | $2,254 |
| | | | | |
| Transportation: | | | | |
| Arkansas | $2,415 | $2,110 | $5,415 | $3,733 |
| Colorado | 819 | 860 | 2,202 | 1,765 |
| Nebraska [(b)] | 15,219 | 14,148 | 33,859 | 25,925 |
| Iowa | 1,119 | 1,080 | 2,590 | 2,555 |
| Kansas | 1,311 | 1,355 | 3,253 | 3,398 |
| Wyoming [(b)] | 5,431 | 5,505 | 14,462 | 10,137 |
| Total Transportation | $26,314 | $25,058 | $61,781 | $47,513 |
| | | | | |
| Transmission: | | | | |
| Arkansas | $450 | $12 | $1,212 | $25 |
| Colorado | 4,018 | 3,613 | 13,764 | 8,751 |
| Wyoming | 1,223 | 1,154 | 2,501 | 2,153 |
| Total Transmission | $5,691 | $4,779 | $17,477 | $10,929 |
| | | | | |
| Other Sales Margins: | | | | |
| Arkansas | $76 | $521 | $662 | $1,290 |
| Colorado | 149 | 292 | 479 | 455 |
| Nebraska | 788 | 873 | 1,787 | 1,674 |
| Iowa | 152 | 213 | 261 | 313 |
| Kansas | 408 | 643 | 442 | 2,622 |
| Wyoming | 262 | 252 | 550 | 446 |
| Total Other Sales Margins | $1,835 | $2,794 | $4,181 | $6,800 |
| | | | | |
| Total Regulated Gross Margin | $98,094 | $94,691 | $270,025 | $219,350 |
| | | | | |
| Non-regulated Services | 6,003 | 8,965 | 17,600 | 16,815 |
| | | | | |
| Total Gross Margin | $104,097 | $103,656 | $287,625 | $236,165 |

(a) Certain prior year revenue classes have been revised to conform to current year presentation.
(b) Change in prior year due to reclassification of Residential Choice customers from Residential to Transportation class.

| Gas Utilities Quantities Sold and Transportation (in Dth) [a] | Three Months Ended June 30, 2017 | 2016 | Six Months Ended June 30, 2017 | 2016 |
|---|---|---|---|---|
| Residential: | | | | |
| Arkansas | 964,399 | 852,523 | 4,528,144 | 2,745,603 |
| Colorado | 2,233,388 | 2,528,067 | 8,270,827 | 6,945,901 |
| Nebraska [b] | 1,220,650 | 1,171,552 | 6,749,118 | 6,656,046 |
| Iowa | 1,116,176 | 1,227,179 | 6,146,579 | 6,265,928 |
| Kansas | 706,934 | 736,678 | 3,634,937 | 3,654,752 |
| Wyoming [b] | 859,789 | 908,572 | 3,039,865 | 2,615,807 |
| Total Residential | 7,101,336 | 7,424,571 | 32,369,470 | 28,884,037 |
| | | | | |
| Commercial: | | | | |
| Arkansas | 871,222 | 696,526 | 3,044,374 | 1,850,100 |
| Colorado | 962,873 | 991,492 | 3,220,623 | 2,434,658 |
| Nebraska | 422,759 | 425,341 | 2,446,483 | 2,416,070 |
| Iowa | 691,573 | 728,477 | 3,291,759 | 3,302,428 |
| Kansas | 345,772 | 275,512 | 1,547,299 | 1,550,400 |
| Wyoming | 666,758 | 660,367 | 2,114,733 | 1,812,068 |
| Total Commercial | 3,960,957 | 3,777,715 | 15,665,271 | 13,365,724 |
| | | | | |
| Industrial: | | | | |
| Arkansas | 259,590 | 184,213 | 609,679 | 345,905 |
| Colorado | 60,849 | 92,781 | 123,036 | 132,129 |
| Nebraska | 8,544 | 14,375 | 31,910 | 32,712 |
| Iowa | 49,208 | 64,611 | 195,328 | 191,810 |
| Kansas [c] | 469,807 | 765,078 | 551,656 | 929,423 |
| Wyoming | 193,034 | 215,516 | 456,310 | 488,067 |
| Total Industrial | 1,041,032 | 1,336,574 | 1,967,919 | 2,120,046 |
| | | | | |
| Total Quantities Sold | 12,103,325 | 12,538,860 | 50,002,660 | 44,369,807 |
| | | | | |
| Transportation: | | | | |
| Arkansas | 2,974,728 | 2,137,721 | 6,099,827 | 3,549,313 |
| Colorado | 1,800,301 | 800,220 | 4,430,569 | 1,598,813 |
| Nebraska [b] | 12,256,613 | 11,429,087 | 28,953,844 | 23,600,182 |
| Iowa | 4,774,801 | 4,635,739 | 10,493,104 | 10,466,083 |
| Kansas | 3,673,537 | 3,234,621 | 7,971,476 | 7,048,006 |
| Wyoming [b] | 5,444,324 | 7,185,846 | 13,788,358 | 12,451,629 |
| Total Transportation | 30,924,304 | 29,423,234 | 71,737,178 | 58,714,026 |
| | | | | |
| Total Quantities Sold and Transportation | 43,027,629 | 41,962,094 | 121,739,838 | 103,083,833 |

(a) Certain prior year revenue classes have been revised to conform to current year presentation.

(b) Change in prior year due to reclassification of Residential Choice customers from Residential to Transportation class.

(c) Decrease is primarily driven by lower irrigation load in 2017 compared to the prior year.

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 geographic location in which our Gas Utilities operate, the winter heating season begins around November 1 and ends around March 31.

| Degree Days | Three Months Ended June 30, 2017 | | | 2016 | |
|---|---|---|---|---|---|
| Heating Degree Days: | Actual | Variance from 30-Year Average | Actual Variance to Prior Year | Actual | Variance from 30-Year Average |
| Arkansas [a] [d] | 242 | (27)% | 4% | 232 | (30)% |
| Colorado | 889 | (7)% | —% | 889 | 3% |
| Nebraska | 567 | (11)% | 29% | 440 | (30)% |
| Iowa | 619 | (10)% | (2)% | 633 | (8)% |
| Kansas [a] | 445 | —% | 9% | 407 | (9)% |
| Wyoming | 1,177 | (4)% | 1% | 1,171 | (12)% |
| Combined [b] [d] | 686 | (9)% | 11% | 620 | (17)% |

| Degree Days | Six Months Ended June 30, 2017 | | | 2016 | |
|---|---|---|---|---|---|
| Heating Degree Days: | Actual | Variance from 30-Year Average | Actual Variance to Prior Year [c] | Actual | Variance from 30-Year Average |
| Arkansas [a] [d] | 1,811 | (26 )% | 52% | 1,189 | (51 )% |
| Colorado | 3,354 | (14 )% | (5)% | 3,517 | (7 )% |
| Nebraska | 3,214 | (12 )% | 3% | 3,121 | (16 )% |
| Iowa | 3,551 | (13 )% | (4)% | 3,715 | (9 )% |
| Kansas [a] | 2,547 | (13 )% | (1)% | 2,570 | (13 )% |
| Wyoming | 4,161 | (6 )% | 4% | 4,020 | (9 )% |
| Combined [b] [d] | 3,404 | (12 )% | 11% | 3,069 | (20 )% |

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(a) Arkansas has a weather normalization mechanism in effect during the months of November through April for customers with residential and business rate schedules. Kansas Gas has an approved weather normalization mechanism within its rate structure, which minimizes weather impact on gross margins. The weather normalization mechanism in Arkansas differs from that in Kansas in that it only uses one location to calculate the weather, compared to Kansas, which uses multiple locations. The weather normalization mechanism in Arkansas minimizes weather impact, but does not eliminate the impact.

(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. Arkansas Gas Distribution is partially excluded based on the weather normalization mechanism in effect from November through April.

(c) The actual variance in heating degree days for the six months ended June 30, 2017 compared to prior year is not a reasonable measurement of weather impacts due to the exclusion of the pre-acquisition heating degree days for the SourceGas utilities in Arkansas, Colorado, Nebraska and Wyoming. These utilities were acquired on February 12, 2016.

(d) In 2016, the 30-year weather average for Arkansas was calculated on average actual daily temperatures. To conform to current year comparisons to normal, the 2016 variances for Arkansas compared to normal and the 2016 combined variance compared to normal have been updated for both of the three and six months ended June 30, 2016.

Regulatory Matters

For more information on enacted regulatory provisions with respect to the states in which our Utilities operate, see Part I, Items 1 and 2 of our 2016 Annual Report on Form 10-K filed with the SEC.

South Dakota Electric Settlement

On June 16, 2017, South Dakota Electric received approval from the SDPUC on a settlement reached with the SDPUC staff agreeing to a six-year moratorium period effective July 1, 2017. As part of this agreement, South Dakota Electric will not increase base rates, absent an extraordinary event. The moratorium period also includes suspension of both the Transmission Facility Adjustment and the Environmental Improvement Adjustment, and a $1.0 million increase to the annual power marketing margin guarantee during this period. Additionally, existing regulatory asset balances of approximately $13 million related to decommissioning and Winter Storm Atlas will be amortized over the moratorium period. These balances were previously being amortized over a 10-year period ending September 30, 2024. The vegetation management regulatory asset of $14 million, previously unamortized, will also be amortized over the moratorium period. The change in amortization periods for these costs will increase annual amortization expense by approximately $2.7 million.

The June 16, 2017 settlement had no impact to base rates. The following table illustrates information about certain enacted regulatory provisions with respect to South Dakota Electric:

| Subsidiary | Jurisdiction | Authorized Rate of Return on Equity | Authorized Return on Rate Base | Authorized Capital Structure Debt/Equity | Authorized Rate Base (in millions) | Effective Date | Tariff and Rate Matters | Percentage of Power Marketing Profit Shared with Customers |
|---|---|---|---|---|---|---|---|---|
| South Dakota Electric | SD | Global Settlement | 7.76% | Global Settlement | $543.9 | 10/2014 | ECA, TCA, Energy Efficiency Cost Recovery/DSM | 70% |

Colorado Electric Rate Case filing

On December 19, 2016, Colorado Electric received approval from the CPUC to increase its annual revenues by $1.2 million to recover investments in a $63 million, 40 MW natural gas-fired combustion turbine and normal increases in operating expenses. This increase is in addition to approximately $5.9 million in annualized revenue being recovered under the Clean Air-Clean Jobs Act construction financing rider. The turbine was completed in the fourth quarter of 2016, achieving commercial operation on December 29, 2016. The approval allowed a return on rate base of 6.02% for this turbine, with a 9.37% return on equity and a capital structure of 67.34% debt and 32.66% equity. An authorized return on rate base of 7.4% was received for the remaining system investments, with a return on equity of 9.37% and an approved capital structure of 47.6% debt and 52.4% equity.

On January 9, 2017, we filed an application with the CPUC for rehearing, reargument or reconsideration of the Commission’s December 19, 2016 decision which reduced our proposed $8.9 million annual revenue increase to $1.2 million. This application was denied by the CPUC on June 9, 2017. We subsequently filed an appeal of this decision with Denver District Court on July 10, 2017.

We believe the CPUC made errors in their December decision by demonstrating bias, making decisions not supported by evidence, making findings inconsistent with cost-recovery provisions of the Colorado Clean Air-Clean Jobs Act and the Commission’s own prior decisions, and treating Colorado Electric differently than other regulated utilities in Colorado have been treated in similar situations.

Gas Utilities Rates and Rate Activity

The following table summarizes recent activity of certain state and federal rate reviews, riders and surcharges (dollars in millions):

| | Type of Service | Date Requested | Effective Date | Revenue Amount Requested | Revenue Amount Approved |
|---|---|---|---|---|---|
| Arkansas Stockton Storage [a] | Gas - storage | 11/2016 | 1/2017 | $ 2.6 | $ 2.6 |
| Arkansas MRP/ARMRP [b] | Gas | 6/2017 | 6/2017 | $ 2.1 | $ 2.1 |
| Kansas Gas [c] | Gas | 5/2017 | 6/2017 | $ 1.4 | $ 1.4 |
| RMNG [d] | Gas - transmission and storage | 11/2016 | 1/2017 | $ 2.9 | $ 2.9 |
| Nebraska Gas Dist. [e] | Gas | 10/2016 | 2/2017 | $ 6.5 | $ 6.5 |

(a) On November 15, 2016, Arkansas Gas filed for the recovery of the Stockton Storage revenue requirement through the Stockton Storage Acquisition Rates regulatory mechanism with the rider effective January 1, 2017. This recovery mechanism was initially approved on October 15, 2015 for the Stockton Storage acquisition.

(b) On June 30, 2017 Arkansas Gas filed for recovery of $1.7 million related to projects for the replacement of eligible mains (MRP) and the recovery of $0.4 million related to projects for the relocation of certain at risk meters (ARMRP). Pursuant to the Arkansas Gas Tariff, the filed rates go into effect on the date of the filing.

(c) On February 21, 2017, Kansas Gas filed with the KCC requesting recovery of $1.4 million, which includes $0.6 million of new revenue related to the Gas System Reliability Surcharge rider (“GSRS”). This GSRS filing was approved by the KCC on May 23, 2017 and went into effect on June 1, 2017.

(d) On November 3, 2016, RMNG filed with the CPUC requesting recovery of $2.9 million, which includes $1.2 million of new revenue related to system safety and integrity expenditures on projects for the period of 2014 through 2017. This SSIR request was approved by the CPUC in December 2016, and went into effect on January 1, 2017.

(e) On October 3, 2016, Nebraska Gas Dist. filed with the NPSC requesting recovery of $6.5 million, which includes $1.7 million of new revenue related to system safety and integrity expenditures on projects for the period of 2012 through 2017. This SSIR tariff was approved by the NPSC in January 2017, and went into effect on February 1, 2017.

Power Generation

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | Variance | 2017 | 2016 | Variance |
| | (in thousands) | | | | | |
| Revenue [a] | $21,795 | $21,714 | $ 81 | $45,362 | $45,022 | $340 |
| Operations and maintenance | 8,528 | 8,648 | (120) | 16,582 | 16,690 | (108) |
| Depreciation and amortization [a] | 1,069 | 1,053 | 16 | 2,276 | 2,084 | 192 |
| Total operating expense | 9,597 | 9,701 | (104) | 18,858 | 18,774 | 84 |
| Operating income | 12,198 | 12,013 | 185 | 26,504 | 26,248 | 256 |
| Interest expense, net | (704) | (120) | (584) | (1,291) | (934) | (357) |
| Other (expense) income, net | (13) | (19) | 6 | (31) | 4 | (35) |
| Income tax (expense) benefit | (3,033) | (3,559) | 526 | (6,688) | (8,421) | 1,733 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Net income | 8,448 | 8,315 | 133 | 18,494 | 16,897 | 1,597 |
| Net income attributable to noncontrolling interest | (3,116) | (2,632) | (484) | (6,632) | (2,632) | (4,000) |
| Net income (loss) available for common stock | $5,332 | $5,683 | $(351) | $11,862 | $14,265 | $(2,403) |

(a) 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.

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million. Black Hills Electric Generation continues to be the majority owner and operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Net income available for common stock for the three and six months ended June 30, 2017, was reduced by $3.1 million and $6.6 million, respectively, and $2.6 million for both the three and six months ended June 30, 2016, attributable to this noncontrolling interest.

Results of Operations for Power Generation for the Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016: Net income available for common stock for the Power Generation segment was $5.3 million for the three months ended June 30, 2017, compared to Net income available for common stock of $5.7 million for the same period in 2016 as a result of:

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

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 increased due to prior year higher interest income associated with the proceeds from the noncontrolling interest sale in April 2016.

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

Income tax (expense) benefit: Black Hills Colorado IPP went from a single member LLC, wholly owned by Black Hills Electric Generation, to a partnership as a result of the sale of 49.9 percent of its membership interest in April 2016. The effective tax rate reflects the income attributable to the noncontrolling interest for which a tax provision is not recorded.

Net income attributable to noncontrolling interest: Net income attributable to noncontrolling interest increased by $0.5 million as a result of the noncontrolling interest sale in April 14, 2016.

Results of Operations for Power Generation for the Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016: Net income available for common stock for the Power Generation segment was $12 million for the six months ended June 30, 2017, compared to Net income available for common stock of $14 million for the same period in 2016 as a result of:

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

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 increased due to prior year higher interest income associated with the proceeds from the noncontrolling interest sale in April 2016.

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

Income tax (expense) benefit: Black Hills Colorado IPP went from a single member LLC, wholly owned by Black Hills Electric Generation, to a partnership as a result of the sale of 49.9% of its membership interest in April 2016.

The effective tax rate reflects the income attributable to the noncontrolling interest for which a tax provision is not recorded.

Net income attributable to noncontrolling interest: Net income attributable to noncontrolling interest increased by $4.0 million as a result of the noncontrolling interest sale in April 2016.

The following table summarizes MWh for our Power Generation segment:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Quantities Sold, Generated and Purchased (MWh) [a] | | | | |
| Sold | | | | |
| Black Hills Colorado IPP [b] | 214,059 | 310,442 | 469,024 | 644,320 |
| Black Hills Wyoming [c] | 142,593 | 141,976 | 312,969 | 309,007 |
| Total Sold | 356,652 | 452,418 | 781,993 | 953,327 |
| | | | | |
| Generated | | | | |
| Black Hills Colorado IPP [b] | 214,059 | 310,442 | 469,024 | 644,320 |
| Black Hills Wyoming [c] | 127,454 | 119,985 | 267,694 | 258,904 |
| Total Generated | 341,513 | 430,427 | 736,718 | 903,224 |
| | | | | |
| Purchased | | | | |
| Black Hills Colorado IPP | — | — | — | — |
| Black Hills Wyoming [c] | 10,962 | 16,936 | 32,217 | 45,239 |
| Total Purchased | 10,962 | 16,936 | 32,217 | 45,239 |

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(a) Company uses and losses are not included in the quantities sold, generated, and purchased.

(b) Decrease from the prior year is a result of the 2017 impact of Colorado Electric's wind generation replacing natural-gas generation.

(c) Under the 20-year economy energy PPA with the City of Gillette, effective September 2014, Black Hills Wyoming purchases energy on behalf of the City of Gillette and sells that energy to the City of Gillette. MWh sold may not equal MWh generated and purchased due to a dispatch agreement Black Hills Wyoming has with South Dakota Electric to cover energy imbalances.

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Contracted power plant fleet availability: | | | | |
| Coal-fired plant | 90.4% | 85.9% | 95.2% | 91.8% |
| Natural gas-fired plants | 99.1% | 99.2% | 99.1% | 99.3% |
| Total availability | 96.9% | 95.8% | 98.1% | 97.4% |

Mining

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | Variance | 2017 | 2016 | Variance |
| | (in thousands) | | | | | |
| Revenue | $14,946 | $11,047 | $3,899 | $31,492 | $27,329 | $4,163 |
| Operations and maintenance | 9,833 | 8,287 | 1,546 | 20,927 | 18,721 | 2,206 |
| Depreciation, depletion and amortization | 2,062 | 2,448 | (386) | 4,227 | 4,927 | (700) |
| Total operating expenses | 11,895 | 10,735 | 1,160 | 25,154 | 23,648 | 1,506 |
| Operating income (loss) | 3,051 | 312 | 2,739 | 6,338 | 3,681 | 2,657 |
| Interest (expense) income, net | (74) | (91) | 17 | (99) | (183) | 84 |
| Other income, net | 536 | 532 | 4 | 1,077 | 1,066 | 11 |
| Income tax benefit (expense) | (832) | (29) | (803) | (1,745) | (902) | (843) |
| Net income (loss) | $2,681 | $724 | $1,957 | $5,571 | $3,662 | $1,909 |

The following table provides certain operating statistics for our Mining segment (in thousands, except for Revenue per ton):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Tons of coal sold | 927 | 614 | 1,976 | 1,616 |
| Cubic yards of overburden moved [(a)] | 1,961 | 1,686 | 4,065 | 3,451 |
| Revenue per ton | $16.12 | $17.99 | $15.94 | $16.91 |

(a) Increase is driven by mining in areas with more overburden than in the prior year as well as higher production.

Results of Operations for Mining for the Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016: Net income available for common stock for the Mining segment was $2.7 million for the three months ended June 30, 2017, compared to Net income available for common stock of $0.7 million for the same period in 2016 as a result of:

Revenue increased due to a 51% increase in tons sold, partially offset by a 10% decrease in price per ton sold. The increased tons sold were driven by an 11-week outage at the Wyodak plant last year. The decrease in price per ton sold was driven by contract price adjustments based on actual mining costs. During the current period, approximately 46% of the mine's production was sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operations and maintenance increased primarily due to higher major maintenance costs and higher royalties and production taxes on increased revenues.

Depreciation, depletion and amortization decreased primarily due to a reduction in asset retirement obligation 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 increased reflecting a prior year tax benefit of percentage depletion.

Results of Operations for Mining for the Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016: Net income available for common stock for the Mining segment was $5.6 million for the six months ended June 30, 2017, compared to Net income available for common stock of $3.7 million for the same period in 2016 as a result of:

Revenue increased due to a 22% increase in tons sold, partially offset by a 6% decrease in price per ton sold. The increased tons sold were driven by an 11-week outage at the Wyodak plant last year. The decrease in price per ton sold was driven by contract price adjustments based on actual mining costs. During the current period, approximately 46% of the mine's production was sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operations and maintenance increased primarily due to higher major maintenance costs and royalties and production taxes on increased revenues.

Depreciation, depletion and amortization decreased primarily due to lower asset retirement obligation 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 increased reflecting a prior year tax benefit of percentage depletion.

Oil and Gas

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | Variance | 2017 | 2016 | Variance |
| | (in thousands) | | | | | |
| Revenue | $6,149 | $7,646 | $(1,497) | $12,624 | $16,021 | $(3,397) |
| Operations and maintenance | 6,149 | 7,912 | (1,763) | 14,309 | 16,947 | (2,638) |
| Depreciation, depletion and amortization | 1,902 | 3,819 | (1,917) | 3,909 | 7,932 | (4,023) |
| Impairment of long-lived assets | — | 25,497 | (25,497) | — | 39,993 | (39,993) |
| Total operating expenses | 8,051 | 37,228 | (29,177) | 18,218 | 64,872 | (46,654) |
| Operating income (loss) | (1,902) | (29,582) | 27,680 | (5,594) | (48,851) | 43,257 |
| Interest income (expense), net | (1,083) | (1,159) | 76 | (2,190) | (2,233) | 43 |
| Other income (expense), net | 11 | 30 | (19) | 17 | 69 | (52) |
| Income tax benefit (expense) | 1,028 | 11,287 | (10,259) | 2,870 | 24,567 | (21,697) |
| Net income (loss) | $(1,946) | $(19,424) | $17,478 | $(4,897) | $(26,448) | $21,551 |

Results of Operations for Oil and Gas for the Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016: Net loss available for common stock for the Oil and Gas segment was $(1.9) million for the three months ended June 30, 2017, compared to Net loss available for common stock of $(19) million for the same period in 2016 as a result of:

Revenue decreased primarily due to a 23% production decrease compared to the same period in the prior year. Natural gas production decreased primarily due to the 2016 sales of non-core properties, and the intentional limiting of gas production to the minimum daily quantities required to meet contractual processing commitments in the Piceance Basin. Crude oil production also decreased due to non-core property sales in the fourth quarter of 2016. The average hedged price received for crude oil sold decreased 25%. The lower production volumes and crude oil pricing was partially offset by a 68% increase in the average hedged price received for natural gas sold.

Operations and maintenance decreased primarily due to lower employee costs and lower production and ad valorem taxes on lower revenue.

Depreciation, depletion and amortization decreased primarily due to the reduction in our full cost pool resulting from the ceiling test impairments incurred in the prior year.

Impairment of long-lived assets represents a prior year non-cash write-down in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices. The prior year write-down of $25 million included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $11 million. The ceiling test write-down in the second quarter of 2016 used a trailing 12 month average NYMEX natural gas price of $2.24 per Mcf, adjusted to $1.01 per Mcf at the wellhead, and $43.12 per barrel for crude oil, adjusted to $37.19 per barrel at the wellhead.

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

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

Income tax (expense) benefit: Each period represents a tax benefit. The effective tax rate is comparable to the same period last year.

Results of Operations for Oil and Gas for the Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016: Net loss available for common stock for the Oil and Gas segment was $(4.9) million for the six months ended June 30, 2017, compared to Net loss available for common stock of $(26) million for the same period in 2016 as a result of:

Revenue decreased primarily due to a 22% production decrease compared to the same period in the prior year. Natural gas production decreased primarily due to the 2016 sales of non-core properties and the intentional limiting of gas production to the minimum daily quantities required to meet contractual processing commitments in the Piceance Basin. Crude oil production also decreased due to non-core property sales in the fourth quarter of 2016. The average hedged price received for crude oil sold decreased 15%. The lower production volumes and crude oil pricing were partially offset by a 48% increase in the average hedged price received for natural gas sold.

Operations and maintenance decreased primarily due to lower employee costs and lower production and ad valorem taxes on lower revenue.

Depreciation, depletion and amortization decreased primarily due to the reduction in our full cost pool resulting from the ceiling test impairments incurred in the prior year.

Impairment of long-lived assets represents a prior year non-cash write-down in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices. The write down of $40 million included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $26 million. The ceiling test write-down for the six months ended June 30, 2016 used an average NYMEX natural gas price of $2.24 per Mcf, adjusted to $1.01 per Mcf at the well head, and $43.12 per barrel for crude oil, adjusted to $37.19 per barrel at the wellhead.

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

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

Income tax (expense) benefit: Each period represents a tax benefit. The effective tax rate for the six months ended June 30, 2016 reflects a benefit of approximately $5.8 million from additional percentage depletion deductions being claimed with respect to a change in estimate for tax purposes. Such deductions were primarily the result of a change in the application of the maximum daily limitation of 1,000 Bbls of oil equivalent allowed under the Internal Revenue Code.

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Production: | | | | |
| Bbls of oil sold | 51,200 | 76,152 | 94,402 | 174,219 |
| Mcf of natural gas sold | 1,962,088 | 2,435,454 | 4,013,810 | 4,722,060 |
| Bbls of NGL sold | 26,986 | 40,892 | 51,729 | 77,895 |
| Mcf equivalent sales | 2,431,204 | 3,137,718 | 4,890,596 | 6,234,744 |

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Average price received: [a] | | | | |

| | | | | |
|---|---|---|---|---|
| Oil/Bbl | $45.02 | $60.16 | $45.38 | $53.22 |
| Gas/Mcf | $1.56 | $0.93 | $1.64 | $1.11 |
| NGL/Bbl | $16.04 | $11.23 | $18.92 | $10.82 |
| | | | | |
| Depletion expense/Mcfe | $0.41 | $0.83 | $0.43 | $0.88 |

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(a) Net of hedge settlement gains and losses.

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

| | Three Months Ended June 30, 2017 | | | | Three Months Ended June 30, 2016 | | | |
|---|---|---|---|---|---|---|---|---|
| Producing Basin | LOE | Gathering, Compression, Processing and Transportation (a) | Production Taxes | Total | LOE | Gathering, Compression, Processing and Transportation (a) | Production Taxes | Total |
| San Juan | $1.55 | $ 1.03 | $ 0.34 | $2.92 | $1.51 | $ 1.05 | $ 0.23 | $2.79 |
| Piceance | 0.51 | 1.99 | 0.07 | 2.57 | 0.34 | 1.80 | 0.09 | 2.23 |
| Powder River | 2.23 | — | 0.75 | 2.98 | 2.95 | — | 0.57 | 3.52 |
| Williston | — | — | — | — | 2.88 | — | 1.00 | 3.88 |
| All other properties | 1.57 | — | 0.24 | 1.81 | 0.19 | — | 0.12 | 0.31 |
| Total weighted average | $1.09 | $ 1.37 | $ 0.26 | $2.72 | $1.07 | $ 1.20 | $ 0.23 | $2.50 |

| | Six Months Ended June 30, 2017 | | | | Six Months Ended June 30, 2016 | | | |
|---|---|---|---|---|---|---|---|---|
| Producing Basin | LOE | Gathering, Compression, Processing and Transportation (a) | Production Taxes | Total | LOE | Gathering, Compression, Processing and Transportation (a) | Production Taxes | Total |
| San Juan | $1.71 | $ 1.15 | $ 0.39 | $3.25 | $1.63 | $ 1.07 | $ 0.27 | $2.97 |
| Piceance | 0.56 | 1.94 | 0.04 | 2.54 | 0.34 | 1.87 | 0.11 | 2.32 |
| Powder River | 2.56 | — | 0.74 | 3.30 | 2.78 | — | 0.56 | 3.34 |
| Williston | — | — | — | — | 1.53 | — | 0.52 | 2.05 |
| All other properties | 1.58 | — | 0.31 | 1.89 | 0.40 | — | 0.07 | 0.47 |
| Total weighted average | $1.18 | $ 1.39 | $ 0.24 | $2.81 | $1.08 | $ 1.17 | $ 0.24 | $2.49 |

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(a) These costs include both third-party costs and operations costs.

In the Piceance and San Juan Basins, our natural gas is transported through our own and third-party gathering systems and pipelines, for which we incur processing, gathering, compression and transportation fees. The sales price for natural gas, condensate and NGLs is reduced for these third-party costs, while the cost of operating our own gathering systems is included in operations and maintenance. The gathering, compression, processing and transportation costs shown in the tables above include amounts paid to third parties, as well as costs incurred in operations associated with our own gas gathering, compression, processing and transportation.

We have a ten-year gas gathering and processing contract for our natural gas production in the Piceance Basin which became effective in March of 2014. This take-or-pay contract requires us to pay a fee on a minimum of 20,000 Mcf per day, regardless of the volume delivered. Our gathering, compression and processing costs on a per Mcfe basis, as shown in the table above, will be higher in periods when we are not meeting the minimum contract requirements.

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016: Net loss available for common stock for Corporate was $(2.4) million for the three months ended June 30, 2017, compared to Net loss available for common stock of $(6.5) million for the three months ended June 30, 2016. The variance from the prior year was primarily due to higher corporate expenses incurred in the prior year related to the SourceGas Acquisition. The second quarter of 2016 included approximately $6.1 million of after-tax acquisition and transition costs, including $4.1 million of incremental non-recurring acquisition costs and $2.0 million of after-tax internal labor related to the SourceGas Acquisition that otherwise would have been charged to other business segments. The second quarter of 2016 also included lower income tax expense compared to the second quarter of 2017.

Results of Operations for Corporate activities for the Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016: Net loss available for common stock for Corporate was $(0.6) million for the six months ended June 30, 2017, compared to Net loss available for common stock of $(22) million for the six months ended June 30, 2016. The variance from the prior year was primarily due to higher corporate expenses incurred in the prior year related to the SourceGas Acquisition. Current year corporate expenses include approximately $1.2 million of after-tax acquisition and transition costs, compared to a total of approximately $26 million of after-tax acquisition and transition costs, which included $20 million of non-recurring incremental acquisition and transition costs and approximately $5.7 million of after-tax internal labor related to the SourceGas Acquisition that otherwise would have been charged to other business segments. During the six months ended June 30, 2017, we recognized a tax benefit of approximately $1.4 million tax benefit from a carryback claim for specified liability losses involving prior years. The same period in the prior year included a tax benefit of approximately $4.4 million recognized as a result of an agreement reached with IRS Appeals relating to the release of the reserve for after-tax interest expense previously accrued with respect to the liability for uncertain tax positions involving a like-kind exchange transaction from 2008.

Critical Accounting Estimates

There have been no material changes in our critical accounting estimates from those reported in our 2016 Annual Report on Form 10-K filed with the SEC. For more information on our critical accounting estimates, see Part II, Item 7 of our 2016 Annual Report on Form 10-K.

Liquidity and Capital Resources

OVERVIEW

Our Company requires significant cash to support and grow our business. Our predominant source of cash is supplied by our operations and supplemented with corporate financings. 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 uses of cash are our capital expenditures, the purchase of natural gas for our Gas Utilities and our Power Generation segment, as well as the payment of dividends to our shareholders. We experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices, as well as during the summer construction season.

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 and acquisitions, 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.

Our Utilities maintain wholesale commodity contracts for the purchases and sales of electricity and natural gas which have performance assurance provisions that allow the counterparty to require collateral postings under certain conditions, including when requested on a reasonable basis due to a deterioration in our financial condition or nonperformance. A significant downgrade in our credit ratings, such as a downgrade to a level below investment grade, could result in counterparties requiring collateral postings under such adequate assurance provisions. The amount of credit support that we may be required to provide at any point in the future is dependent on the amount of the initial transaction, changes in the market price, open positions and the amounts owed by or to the counterparty.

At June 30, 2017, we had $2.5 million of collateral posted related to our wholesale commodity contracts transactions. At June 30, 2017, we had sufficient liquidity to cover any additional collateral that could be required to be posted under these contracts.

Cash Flow Activities

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

| Cash provided by (used in): | 2017 | 2016 | Increase (Decrease) |
|---|---|---|---|
| Operating activities | $262,869 | $183,503 | $79,366 |
| Investing activities | $(163,790) | $(1,324,741) | $1,160,951 |
| Financing activities | $(101,069) | $762,236 | $(863,305 ) |

Year-to-Date 2017 Compared to Year-to-Date 2016

Operating Activities

Net cash provided by operating activities was $263 million for the six months ended June 30, 2017, compared to net cash provided by operating activities of $184 million for the same period in 2016 for a variance of $79 million. The variance was primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $48 million higher for the six months ended June 30, 2017 compared to the same period in the prior year;

- Net cash inflows from changes in operating assets and liabilities were $1.1 million for the six months ended June 30, 2017, compared to net cash outflows of $20 million in the same period in the prior year. This $21 million variance was primarily due to:

Cash inflows increased by approximately $5.5 million for the six months ended June 30, 2017 primarily as a result of changes in our accounts receivable driven by higher commodity prices, partially offset by higher natural gas in storage for the six months ended June 30, 2017 compared to the same period in the prior year;

Cash outflows decreased by approximately $11 million as a result of changes in accounts payable and accrued liabilities driven by changes in working capital requirements, primarily related to acquisition and transaction costs that took place in the prior year;

Cash inflows increased by approximately $4.1 million as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and commodity price impacts on working capital compared to the same period in the prior year; and

- Net cash outflows decreased by $10 million due to pension contributions made in the prior year.

Investing Activities

Net cash used in investing activities was $164 million for the six months ended June 30, 2017, compared to net cash used in investing activities of $1.325 billion for the same period in 2016. The variance was primarily driven by:

- The prior year's cash outflows included $1.124 billion for the acquisition of SourceGas, net of $760 million of long term debt assumed (see Note 2 of our Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K for more details); and

- Capital expenditures of approximately $164 million for the six months ended June 30, 2017 compared to $200 million for the six months ended June 30, 2016. The variance to the prior year was due primarily to higher prior year capital expenditures at our Electric Utilities primarily from generation investments at Colorado Electric.

Financing Activities

Net cash used in financing activities for the six months ended June 30, 2017 was $101 million, compared to $762 million of net cash provided by financing activities for the same period in 2016. The $863 million variance was primarily driven by:

- Proceeds of $216 million from the sale of a 49.9% noncontrolling interest of Colorado IPP that took place in the prior year;

- Long-term borrowings were higher in the prior year due to the $546 million of net proceeds from our January 13, 2016 public debt offering used to partially finance the SourceGas Acquisition and proceeds from a $29 million term loan used to fund the early settlement of a gas gathering contract;

- Net short-term borrowings increased by $13 million primarily due to CP borrowings used to pay down other long-term debt;

- Proceeds from common stock decreased by approximately $54 million due to prior year stock issuances under our ATM equity offering program;

- Current year distributions to noncontrolling interests of $8.3 million;

- Increased dividend payments of approximately $4.3 million;

- Higher current year payments on long-term debt of $11 million; and

- Higher other financing activities in the current year primarily driven by the $5.6 million paid for a redeemable noncontrolling interest in March 2017.

Dividends

Dividends paid on our common stock totaled $48 million for the six months ended June 30, 2017, or $0.445 per share. On July 26, 2017, our board of directors declared a quarterly dividend of $0.445 per share payable September 1, 2017, which is equivalent to an annual dividend rate of $1.78 per share. The amount of any future cash dividends to be declared and paid, if any, 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, our CP Program and our corporate Revolving Credit Facility.

Revolving Credit Facility and CP Program

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extended the term through August 9, 2021 with two one-year extension options. This facility is 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 total commitments of the facility to up to $1 billion. 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 or Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.250%, 1.250%, and 1.250%, respectively, at June 30, 2017. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

On December 22, 2016, we implemented a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption.

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

| Credit Facility | Expiration | Current Capacity | Revolver Borrowings at June 30, 2017 | CP Program Borrowings at June 30, 2017 | Letters of Credit at June 30, 2017 | Available Capacity at June 30, 2017 |
|---|---|---|---|---|---|---|
| Revolving Credit Facility | August 9, 2021 | $ 750 | $ — | $ 108 | $ 25 | $ 617 |

The weighted average interest rate on CP Program borrowings at June 30, 2017 was 1.41%. Revolving Credit Facility and CP Program financing activity for the six months ended June 30, 2017 was (dollars in millions):

| | For the Six Months Ended June 30, 2017 |
|---|---|
| Maximum amount outstanding - commercial paper (based on daily outstanding balances) | $ 122 |
| Maximum amount outstanding - revolving credit facility (based on daily outstanding balances) | $ 97 |

| | |
|---|---|
| Average amount outstanding - commercial paper (based on daily outstanding balances) [(a)] | $ 72 |
| Average amount outstanding - revolving credit facility (based on daily outstanding balances) [(a)] | $ 55 |
| Weighted average interest rates - commercial paper [(a)] | 1.19 % |
| Weighted average interest rates - revolving credit facility [(a)] | 2.07 % |

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(a) Averages for the Revolving Credit Facility are for the first 29 days of the year after which all borrowings were through the CP Program.

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on certain liens, restrictions on certain transactions, and maintenance of a certain Consolidated Indebtedness to Capitalization Ratio. Under the Revolving Credit Facility, our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit, certain guarantees issued and excludes RSNs by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs. 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, 2017.

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.

Financing Activities

Financing activities for the six months ended June 30, 2017 consisted of short-term borrowings from our Revolving Credit Facility and CP Program. We also made a principal payment of $50 million on our Corporate term loan due August 9, 2019. An additional $50 million was paid on the same term loan on July 17, 2017. Short-term borrowings from our CP program were used to fund the payments on the Corporate term loan. We did not issue any shares of common stock under our ATM equity offering program.

In addition to the CP Program and amended Revolving Credit Facility discussed above, other financing activities from the prior year consisted of completing the permanent financing for the SourceGas Acquisition. In addition to the net proceeds of $536 million from our November 2015 equity issuances, we completed the Acquisition financing with $546 million of net proceeds from our January 2016 debt offering. We also refinanced the long-term debt assumed with the SourceGas Acquisition primarily through $693 million of net proceeds from our August 19, 2016 debt offerings. In addition to our debt refinancings, we issued a total of 1.97 million shares of common stock throughout 2016 for net proceeds of approximately $119 million through our ATM equity offering program, and sold a 49.9% noncontrolling interest in Black Hills Colorado IPP for $216 million in April 2016.

Future Financing Plans

We anticipate the following financing activities:

- Renewing our shelf registration and ATM equity offering program; expected filing on August 4, 2017;
- Remarketing the junior subordinated notes maturing in 2018;
- Evaluating a one-to-two year extension of our Revolving Credit Facility and CP program to be completed in 2018; and
- Evaluating refinancing options for term loan and short-term borrowings under Revolving Credit Facility and CP program.

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 Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming 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 the 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, 2017, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 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 and existing term loans is a Consolidated Indebtedness to Capitalization Ratio, which requires us to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00 at the end of any fiscal quarter. Our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit, certain guarantees issued and excludes RSNs by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs. 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, 2017, we were in compliance with these covenants.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2016 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, the Company's credit ratings, cash flows from routine operations and the credit ratings of counterparties. After assessing the current operating performance, liquidity and the credit ratings of the Company, management believes that the Company will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. BHC notes that credit ratings 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 and risk profile of BHC at June 30, 2017:

| Rating Agency | Senior Unsecured Rating | Outlook |
|---|---|---|
| S&P [(a)] | BBB | Stable |
| Moody's[(b)] | Baa2 | Stable |
| Fitch [(c)] | BBB+ | Stable |

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(a) On July 21, 2017, S&P affirmed BBB rating and maintained a Stable outlook.

(b) On December 9, 2016, Moody's issued a Baa2 rating with a Stable outlook, which reflects the higher debt leverage resulting from the incremental debt used to fund the SourceGas Acquisition.

(c) On March 29, 2017, Fitch affirmed BBB+ rating and changed their outlook from Negative to Stable, citing successful integration of SourceGas, a low business risk profile focused on utility operations and expected improvement of credit metrics.

The following table represents the credit ratings of Black Hills Power at June 30, 2017:

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

There were no rating changes for Black Hills Power from previously disclosed ratings.

Capital Requirements

Capital Expenditures

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

| | Expenditures for the Six Months Ended June 30, 2017 [a] | Total 2017 Planned Expenditures [b] | Total 2018 Planned Expenditures | Total 2019 Planned Expenditures |
|---|---|---|---|---|
| Electric Utilities | $ 80,529 | $ 126,000 | $ 128,000 | $ 192,000 |
| Gas Utilities | 73,696 | 185,000 | 213,000 | 260,000 |
| Power Generation | 1,823 | 2,000 | 3,000 | 8,000 |
| Mining | 4,037 | 7,000 | 7,000 | 8,000 |
| Oil and Gas [c] | 11,782 | 20,000 | 1,000 | — |
| Corporate | 2,603 | 10,000 | 12,000 | 10,000 |
| | $ 174,470 | $ 350,000 | $ 364,000 | $ 478,000 |

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(a) Expenditures for the six months ended June 30, 2017 include the impact of accruals for property, plant and equipment.
(b) Includes actual capital expenditures for the six months ended June 30, 2017.
(c) Expenditures reflect the completion of two wells previously drilled in 2015 to meet minimum daily quantity requirements for the Piceance Basin gathering and processing contract.

We have updated our planned 2018 and 2019 capital expenditures to primarily reflect the following:

- additional planned transmission and distribution investments at our Electric Utilities in 2018 and 2019; and
- additional planned growth and integrity investments in our Gas utilities, primarily as a result of gaining further knowledge of the SourceGas utilities.

We continue to evaluate potential future acquisitions and other growth opportunities when they arise. As a result, capital expenditures may vary significantly from the estimates identified above.

Contractual Obligations

There have been no significant changes in contractual obligations from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K except for those described in Note 16 of the Notes to Condensed Consolidated Financial Statements in Item 1 of Part I of this Quarterly Report on Form 10-Q.

Guarantees

There have been no significant changes to guarantees from those previously disclosed in Note 20 of the Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the pronouncements reported in our 2016 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 inc 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 2016 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2016 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, 2017 | December 31, 2016 | June 30, 2016 |
|---|---|---|---|
| Net derivative (liabilities) assets | $(7,075) | $(4,733 ) | $(7,894 ) |
| Cash collateral offset in Derivatives | 6,950 | 7,882 | 10,251 |
| Cash collateral included in Other current assets | 2,339 | 4,840 | 8,067 |
| Net asset (liability) position | $2,214 | $7,989 | $10,424 |

Oil and Gas Activities

We have entered into agreements to hedge a portion of our estimated 2017 and 2018 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at June 30, 2017, were as follows:

Natural Gas

| | March 31 | June 30 | September 30 | December 31 | Total Year |
|---|---|---|---|---|---|
| 2017 | | | | | |
| Swaps - MMBtu | — | — | 540,000 | 540,000 | 1,080,000 |
| Weighted Average Price per MMBtu | $ | —$ | —$ 3.04 | $ 3.04 | $ 3.04 |

Crude Oil

| | March 31 | June 30 | September 30 | December 31 | Total Year |
|---|---|---|---|---|---|
| 2017 | | | | | |
| Swaps - Bbls | — | — | 18,000 | 18,000 | 36,000 |
| Weighted Average Price per Bbl | $— | $— | $ 51.55 | $ 52.33 | $51.94 |
| | | | | | |
| Calls - Bbls | — | — | 9,000 | 9,000 | 18,000 |
| Weighted Average Price per Bbl | $— | $— | $ 50.00 | $ 50.00 | $50.00 |
| | | | | | |
| 2018 | | | | | |
| Swaps - Bbls | 9,000 | 9,000 | 9,000 | 9,000 | 36,000 |
| Weighted Average Price per Bbl | $49.58 | $49.85 | $ 50.12 | $ 50.45 | $50.00 |

The fair value of our Oil and Gas segment's derivative contracts is summarized below (in thousands) as of:

| | June 30, 2017 | December 31, 2016 | June 30, 2016 |
|---|---|---|---|
| Net derivative (liabilities) assets | $497 | $(1,433 ) | $2,520 |
| Cash collateral offset in Derivatives | 230 | 2,733 | (1,150 ) |
| Cash Collateral included in Other current assets | — | — | — |

| | | | |
|---|---|---|---|
| Net asset (liability) position | $ 727 | $ 1,300 | $ 1,370 |

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. Historically, 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 and anticipated long-term refinancings. Further details of the swap agreements are set forth in Note 9 of the Notes to Consolidated Financial Statements in our 2016 Annual Report on Form 10-K and in Note 10 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, 2017 | December 31, 2016 | June 30, 2016 | | |
|---|---|---|---|---|---|
| | Designated Interest Rate Swaps | Designated Interest Rate Swap [(a)] | Designated Interest Rate Swap [(b)] | Designated Interest Rate Swap [(b)] | Designated Interest Rate Swaps [(a)] |
| Notional | $ — | $ 50,000 | $ 150,000 | $ 250,000 | $ 75,000 |
| Weighted average fixed interest rate | — % | 4.94 % | 2.09 % | 2.29 % | 4.97 % |
| Maximum terms in months | 0 | 1 | 10 | 10 | 6 |
| Derivative assets, non-current | $ — | $ — | $ — | $ — | $ — |
| Derivative liabilities, current | $ — | $ 90 | $ 8,553 | $ 18,500 | $ 1,505 |
| Derivative liabilities, non-current | $ — | $ — | $ — | $ — | $ — |
| Pre-tax accumulated other comprehensive income (loss) | $ — | $ (90 ) | $ (8,553 ) | $ (18,500 ) | $ (1,505 ) |

(a) The $25 million in swaps expired in October 2016 and the $50 million in swaps expired in January 2017. These swaps were designated to borrowings on our Revolving Credit Facility and were priced using three-month LIBOR, matching the floating portion of the related borrowings.

(b) These swaps were settled and terminated in August 2016 in conjunction with the refinancing of acquired SourceGas debt.

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, 2017. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective at June 30, 2017.

Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Security Exchange Act of 1934, as amended, is recorded, processed, summarized and reported, within the time periods specified in the Commission’s rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2017, 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.

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BLACK HILLS CORPORATION

## Part II — Other Information

### ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 2016 Annual Report on Form 10-K and Note 16 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 16 is incorporated by reference into this item.

### ITEM 1A. Risk Factors

There are no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2016 Annual Report on Form 10-K filed with the SEC.

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

There were no unregistered securities sold during the six months ended June 30, 2017.

### 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 2.1* | Purchase and Sale Agreement by and among Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer dated as of July 12, 2015 (filed as Exhibit 2.1 to the Registrant's Form 8-K file on July 14, 2015). First Amendment to Purchase and Sale Agreement effective December 10, 2015, by and among, Alinda Gas Delaware LLC, Alinda Infrastructure Fund I L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant’s Form 10-K for 2015). |
| Exhibit 2.2* | Option Agreement by and among Aircraft Services Corporation, as ASC, SourceGas Holdings LLC, as the Company and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 8-K file on July 14, 2015). |
| Exhibit 2.3* | Guaranty of Black Hills Corporation in favor of Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, dated as of July 12, 2015 (filed as Exhibit 2.3 to the Registrant's Form 8-K file on July 14, 2015). |
| 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 April 24, 2017 (filed as Exhibit 3 to the Registrant’s Form 8-K filed on April 28, 2017). |
| 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). Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant’s Form 8-K filed on January 13, 2016). Sixth Supplemental Indenture dated as of August 19, 2016 (filed as Exhibit 4.1 to the Registrant’s Form 8-K filed on August 19, 2016). |
| 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)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on October 2, 2014). |

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|---|---|
| Exhibit 4.3* | Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant’s Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant’s Form 8-K filed on October 2, 2014). Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant’s Form 8-K filed on October 2, 2014). |
| Exhibit 4.4* | Junior Subordinated Indenture dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Registrant’s Form 8-K filed on November 23, 2015). First Supplemental Indenture dated as of November 23, 2015 (filed as Exhibit 4.2 to the Registrant’s Form 8-K filed on November 23, 2015). |

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| Exhibit 4.5* | Purchase Contract and Pledge Agreement dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as purchase contract agent, collateral agent, custodial agent and securities intermediary (filed as Exhibit 4.4 to the Registrant's Form 8-K filed on November 23, 2015). |
| Exhibit 4.6* | Indenture dated as of April 16, 2007 between SourceGas LLC and U.S. Bank National Association, as Trustee (relating to $325 million, 5.90% Senior Notes due 2017) (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on March 18, 2016). |
| Exhibit 4.7* | 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 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.
†Indicates a board of director or management compensatory plan.

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 and
Chief Executive Officer

/s/ Richard W. Kinzley
Richard W. Kinzley, Senior Vice President and
Chief Financial Officer

Dated: August 4, 2017

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