

BLACK HILLS CORP /SD/
Form 10-Q
May 04, 2018

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

Form 10-Q

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

For the quarterly period ended March 31, 2018

OR

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

For the transition period from _____ to _____.

Commission File Number 001-31303

Black Hills Corporation
Incorporated in South Dakota IRS Identification Number 46-0458824
7001 Mount Rushmore Road
Rapid City, South Dakota 57702

Registrant's telephone number (605) 721-1700

Former name, former address, and former fiscal year if changed since
last report

NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes No

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 Accelerated filer

Non-accelerated filer (Do not check if a smaller
reporting company)

Smaller reporting company

Emerging growth company

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.

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

Yes No

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

| Class | Outstanding at April 30, 2018 |
|--------------------------------|----------------------------------|
| Common stock, \$1.00 par value | 53,592,446 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) |
| Arkansas Gas | Black Hills Energy Arkansas, Inc., a direct, wholly-owned subsidiary of Black Hills Gas Inc. |
| 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 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 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 |
| CAPP | Customer Appliance Protection Plan |
| 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 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. |
| 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 |
| Dth | Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu) |
| 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
Fitch
GAAP

United States Federal Energy Regulatory Commission
Fitch Ratings
Accounting principles generally accepted in the United States of America

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| | |
|---------------------------|---|
| Heating Degree Day | A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average. |
| IPP | Independent power producer |
| IRS | United States Internal Revenue Service |
| 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) |
| LIBOR | London Interbank Offered Rate |
| MMBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| 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) |
| 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 |
| 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 |
| 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 |
| TCJA | Tax Cuts and Jobs Act enacted on December 22, 2017 |
| 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. |
| Wyodak Plant | Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, 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 |

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

| (unaudited) | Three Months Ended March 31, 2018 2017 (in thousands, except per share amounts) | |
|---|--|-----------|
| Revenue | \$575,389 | \$547,528 |
| Operating expenses: | | |
| Fuel, purchased power and cost of natural gas sold | 247,639 | 219,777 |
| Operations and maintenance | 116,096 | 114,552 |
| Depreciation, depletion and amortization | 48,590 | 46,702 |
| Taxes - property, production and severance | 13,300 | 13,386 |
| Other operating expenses | 1,490 | 2,925 |
| Total operating expenses | 427,115 | 397,342 |
| Operating income | 148,274 | 150,186 |
| Other income (expense): | | |
| Interest charges - | | |
| Interest expense incurred (including amortization of debt issuance costs, premiums and discounts) | (35,455) | (35,058) |
| Allowance for funds used during construction - borrowed | 133 | 486 |
| Capitalized interest | 17 | 75 |
| Interest income | 310 | 41 |
| Allowance for funds used during construction - equity | 68 | 492 |
| Other income (expense), net | (172) | (119) |
| Total other income (expense), net | (35,099) | (34,083) |
| Income before income taxes | 113,175 | 116,103 |
| Income tax benefit (expense) | 25,802 | (34,388) |
| Income from continuing operations | 138,977 | 81,715 |
| (Loss) from discontinued operations, net of tax | (2,343) | (1,569) |
| Net income | 136,634 | 80,146 |
| Net income attributable to noncontrolling interest | (3,630) | (3,623) |
| Net income available for common stock | \$133,004 | \$76,523 |
| Amounts attributable to common shareholders: | | |
| Net income from continuing operations | 135,347 | 78,092 |
| Net (loss) from discontinued operations | (2,343) | (1,569) |
| Net income (loss) available for common stock | \$133,004 | \$76,523 |
| Earnings per share of common stock: | | |
| Earnings (loss) per share, Basic - | | |
| Income from continuing operations, per share | \$2.54 | \$1.47 |

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| | | | |
|--|---------|---------|---|
| (Loss) from discontinued operations, per share | (0.05 |)(0.03 |) |
| Earnings per share, Basic | \$2.49 | \$1.44 | |
| Earnings (loss) per share, Diluted - | | | |
| Income from continuing operations, per share | \$2.50 | \$1.42 | |
| (Loss) from discontinued operations, per share | (0.04 |)(0.03 |) |
| Earnings per share, Diluted | \$2.46 | \$1.39 | |
| Weighted average common shares outstanding: | | | |
| Basic | 53,319 | 53,152 | |
| Diluted | 54,122 | 54,932 | |
| Dividends declared per share of common stock | \$0.475 | \$0.445 | |

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 March 31, 2018 2017 (in thousands) | |
|---|--|-----------|
| Net income | \$ 136,634 | \$ 80,146 |
| Other comprehensive income (loss), net of tax: | | |
| Reclassification adjustments of benefit plan liability - prior service cost (net of tax benefit of \$10 and \$17 for the three months ended March 31, 2018 and 2017, respectively) | (35) |)(31) |
| Reclassification adjustments of benefit plan liability - net gain (net of tax expense of \$(136) and \$(154) for the three months ended March 31, 2018 and 2017, respectively) | 486 | 260 |
| Derivative instruments designated as cash flow hedges: | | |
| Net unrealized gains (losses) on interest rate swaps (net of tax of \$0 and \$(32) for the three months ended March 31, 2018 and 2017, respectively) | — | 58 |
| Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of \$(152) and \$(249) for the three months ended March 31, 2018 and 2017, respectively) | 561 | 463 |
| Net unrealized gains (losses) on commodity derivatives (net of tax of \$69 and \$(342) for the three months ended March 31, 2018 and 2017, respectively) | (228) |)584 |
| Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of \$(145) and \$106 for the three months ended March 31, 2018 and 2017, respectively) | 476 | (181) |
| Other comprehensive income, net of tax | 1,260 | 1,153 |
| Comprehensive income | 137,894 | 81,299 |
| Less: comprehensive income attributable to noncontrolling interest | (3,630) |)(3,623) |
| Comprehensive income available for common stock | \$ 134,264 | \$ 77,676 |

See Note 14 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 | | |
|--|--------------------|----------------------|--------------------|
| | March 31, 2018 | December 31, 2017 | March 31, 2017 |
| | (in thousands) | | |
| ASSETS | | | |
| Current assets: | | | |
| Cash and cash equivalents | \$30,947 | \$15,420 | \$11,291 |
| Restricted cash | 2,958 | 2,820 | 2,409 |
| Accounts receivable, net | 257,772 | 248,330 | 221,775 |
| Materials, supplies and fuel | 82,045 | 113,283 | 80,863 |
| Derivative assets, current | 295 | 304 | 982 |
| Income tax receivable, net | 13,900 | — | — |
| Regulatory assets, current | 54,492 | 81,016 | 53,476 |
| Other current assets | 24,972 | 25,367 | 21,558 |
| Current assets held for sale | 24,724 | 84,242 | 9,048 |
| Total current assets | 492,105 | 570,782 | 401,402 |
| Investments | 40,927 | 13,090 | 12,712 |
| Property, plant and equipment | 5,608,539 | 5,567,518 | 5,337,031 |
| Less: accumulated depreciation and depletion | (1,048,933) | (1,026,088) | (928,306) |
| Total property, plant and equipment, net | 4,559,606 | 4,541,430 | 4,408,725 |
| Other assets: | | | |
| Goodwill | 1,299,454 | 1,299,454 | 1,299,454 |
| Intangible assets, net | 7,357 | 7,559 | 8,182 |
| Regulatory assets, non-current | 212,740 | 216,438 | 249,113 |
| Other assets, non-current | 14,800 | 10,149 | 11,291 |
| Noncurrent assets held for sale | — | — | 108,692 |
| Total other assets, non-current | 1,534,351 | 1,533,600 | 1,676,732 |
| TOTAL ASSETS | \$6,626,989 | \$6,658,902 | \$6,499,571 |

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 | | |
|--|--------------------------------------|----------------------|--------------------|
| | March 31, 2018 | December 31, 2017 | March 31, 2017 |
| | (in thousands, except share amounts) | | |
| LIABILITIES AND TOTAL EQUITY | | | |
| Current liabilities: | | | |
| Accounts payable | \$106,281 | \$160,887 | \$104,375 |
| Accrued liabilities | 194,040 | 219,462 | 196,576 |
| Derivative liabilities, current | 891 | 2,081 | 75 |
| Accrued income taxes, net | — | 1,022 | 3,726 |
| Regulatory liabilities, current | 42,499 | 6,832 | 22,118 |
| Notes payable | 164,200 | 211,300 | 50,950 |
| Current maturities of long-term debt | 255,743 | 5,743 | 5,743 |
| Current liabilities held for sale | 24,910 | 41,774 | 7,979 |
| Total current liabilities | 788,564 | 649,101 | 391,542 |
| Long-term debt | 2,858,787 | 3,109,400 | 3,210,730 |
| Deferred credits and other liabilities: | | | |
| Deferred income tax liabilities, net | 290,491 | 336,520 | 600,933 |
| Regulatory liabilities, non-current | 495,362 | 478,294 | 196,538 |
| Benefit plan liabilities | 160,580 | 159,646 | 174,827 |
| Other deferred credits and other liabilities | 105,221 | 105,735 | 112,828 |
| Non-current liabilities held for sale | — | — | 23,195 |
| Total deferred credits and other liabilities | 1,051,654 | 1,080,195 | 1,108,321 |
| Commitments and contingencies (See Notes 9, 11, 16, 17) | | | |
| Equity: | | | |
| Stockholders' equity — | | | |
| Common stock \$1 par value; 100,000,000 shares authorized; issued 53,648,817; 53,579,986; and 53,502,252 shares, respectively | 53,649 | 53,580 | 53,502 |
| Additional paid-in capital | 1,151,933 | 1,150,285 | 1,143,102 |
| Retained earnings | 656,161 | 548,617 | 513,885 |
| Treasury stock, at cost – 53,959; 39,064; and 41,443 shares, respectively | (3,049) | (2,306) | (2,443) |
| Accumulated other comprehensive income (loss) | (39,924) | (41,202) | (33,730) |
| Total stockholders' equity | 1,818,770 | 1,708,974 | 1,674,316 |
| Noncontrolling interest | 109,214 | 111,232 | 114,662 |
| Total equity | 1,927,984 | 1,820,206 | 1,788,978 |
| TOTAL LIABILITIES AND TOTAL EQUITY | \$6,626,989 | \$6,658,902 | \$6,499,571 |

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

| | Three Months Ended March 31, | |
|---|---------------------------------|------------|
| | 2018 | 2017 |
| | (in thousands) | |
| Operating activities: | | |
| Net income | \$ 136,634 | \$ 80,146 |
| Loss from discontinued operations, net of tax | 2,343 | 1,569 |
| Income (loss) from continuing operations | 138,977 | 81,715 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 48,590 | 46,702 |
| Deferred financing cost amortization | 1,900 | 1,690 |
| Stock compensation | 2,209 | 3,091 |
| Deferred income taxes | (25,430) |)41,213 |
| Employee benefit plans | 3,378 | 3,242 |
| Other adjustments, net | 3,053 | (2,303) |
| Changes in certain operating assets and liabilities: | | |
| Materials, supplies and fuel | 31,196 | 22,461 |
| Accounts receivable, unbilled revenues and other operating assets | (25,113) |)38,746 |
| Accounts payable and other operating liabilities | (71,149) |)(98,559) |
| Regulatory assets - current | 47,903 | 236 |
| Regulatory liabilities - current | 16,098 | 9,083 |
| Other operating activities, net | (278) |)(1,644) |
| Net cash provided by operating activities of continuing operations | 171,334 | 145,673 |
| Net cash provided by (used in) operating activities of discontinued operations | (1,459) |)1,167 |
| Net cash provided by (used in) operating activities | 169,875 | 146,840 |
| Investing activities: | | |
| Property, plant and equipment additions | (69,972) |)(66,480) |
| Purchase of investment | (23,500) |)— |
| Other investing activities | (261) |)(50) |
| Net cash provided by (used in) investing activities of continuing operations | (93,733) |)(66,530) |
| Net cash provided by (used in) investing activities of discontinued operations | 20,179 | (2,829) |
| Net cash provided by (used in) investing activities | (73,554) |)(69,359) |
| Financing activities: | | |
| Dividends paid on common stock | (25,444) |)(23,754) |
| Common stock issued | 372 | 2,171 |
| Net (payments) borrowings of short-term debt | (47,100) |)(45,650) |
| Long-term debt - repayments | (1,436) |)(1,436) |
| Distributions to noncontrolling interest | (5,648) |)(4,349) |
| Other financing activities | (1,400) |)(6,555) |
| Net cash provided by (used in) financing activities | (80,656) |)(79,573) |
| Net change in cash, cash equivalents and restricted cash | 15,665 | (2,092) |
| Cash, cash equivalents and restricted cash at beginning of period | 18,240 | 15,792 |
| Cash, cash equivalents and restricted cash at end of period | \$ 33,905 | \$ 13,700 |

See Note 15 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.

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BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)

(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2017 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 2017 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 and Mining. 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.

On November 1, 2017, the BHC board of directors approved a complete divestiture of our Oil and Gas segment. The Oil and Gas segment assets and liabilities are classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, excluding certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. As of May 4, 2018, we have executed agreements to sell or we have closed on sales transactions for approximately 96% of our oil and gas properties. We expect to execute agreements to sell all remaining assets by mid-year 2018. See Note 18 for more information on discontinued operations.

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 March 31, 2018, December 31, 2017, and March 31, 2017 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 months ended March 31, 2018 and March 31, 2017, and our financial condition as of March 31, 2018, December 31, 2017, and March 31, 2017, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

Cash and Cash Equivalents and Restricted Cash

For purposes of the cash flow statements, we consider all highly liquid investments with original maturities of three months or less at the time of purchase to be cash equivalents.

Investments

We account for investments that we do not control under the cost method of accounting as we do not have the ability to exercise significant influence over the operating and financial policies of the investee. The cost method investments are recorded at cost and we record dividend income when applicable dividends are declared.

Recently Issued Accounting Standards

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 most leases, 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. Under the current guidance, 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. In January 2018, the FASB issued amendments to the new lease standard, ASU No. 2018-01, allowing an entity to elect not to assess whether certain land easements are, or contain, leases when transitioning to the new lease standard.

We currently expect to adopt this standard on January 1, 2019 and anticipate electing not to assess existing or expired land easements that were not previously accounted for as a lease when transitioning to the new standard. We continue to evaluate the impact of this new standard on our financial position, results of operations and cash flows as well as monitor utility industry implementation guidance. We continue the process of identifying and categorizing our lease contracts and evaluating our current business processes relating to leases. We have selected and initiated implementation of a new lease software solution.

Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities, 2017-12

In August 2017, the FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities. This standard better aligns risk management activities and financial reporting for hedging relationships, simplifies hedge accounting requirements and improves disclosures of hedging arrangements. This ASU is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. We do not anticipate the adoption of this guidance to have a material impact on our financial position, results of operations or cash flows.

Simplifying the Test for Goodwill Impairment, 2017-04

In January 2017, the FASB issued ASU 2017-04, Simplifying the Test for Goodwill Impairment by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the amount of goodwill allocated to that reporting unit. The new standard is effective for interim and annual reporting periods beginning after December 15, 2019, applied on a prospective basis with early adoption permitted. We do not anticipate the adoption of this standard to have any impact on our financial position, results of operations or cash flows.

Recently Adopted Accounting Standards

Revenue from Contracts with Customers, ASU 2014-09

Effective January 1, 2018, we adopted ASU 2014-09, Revenue from Contracts with Customers, and its related amendments (collectively known as ASC 606). Under this standard, revenue is recognized when a customer obtains

control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In addition, the standard requires disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. We applied the five-step method outlined in the ASU to all in-scope revenue streams and elected the modified retrospective implementation method. Implementation of the standard did not have a material impact on our financial position, results of operations or cash flows. Implementation of the standard did not have a significant impact on the measurement or recognition of revenue; therefore, no cumulative adoption adjustment to the opening balance of Retained earnings at the date of initial application was necessary. The additional disclosures required by the ASU are included in Note 2.

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

Effective January 1, 2018, we adopted ASU 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost. The standard requires 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. The capitalization of only the service cost component of net periodic pension and post-retirement benefit costs in assets was applied on a prospective basis. For our rate-regulated entities, we capitalize the other components of net periodic benefit costs into regulatory assets or regulatory liabilities and maintain a FERC-to-GAAP reporting difference for these capitalized costs. The presentation changes required for net periodic pension and post-retirement costs resulted in offsetting changes to Operating income and Other income. Implementation of the standard did not have a material impact on our financial position, results of operations or cash flows.

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

Effective January 1, 2018, we adopted 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. We implemented this standard effective January 1, 2018 using the retrospective transition method. This standard had no impact on our financial position, results of operations or cash flows.

Statement of Cash Flows: Restricted Cash, ASU 2016-18

Effective January 1, 2018, we adopted ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash. This ASU provides guidance on the presentation of restricted cash or restricted cash equivalents and reduces the diversity in practice. This ASU requires amounts generally described as restricted cash and restricted cash equivalents to be included with cash and cash equivalents when reconciling beginning-of-period and end-of-period total amounts on the statement of cash flows. We elected, as permitted by the standard, to early adopt ASU 2016-18 retrospectively as of January 1, 2017 and have applied it to all periods presented herein. The adoption of ASU 2016-18 did not have a material impact to our condensed consolidated financial statements. The effect of the adoption of ASU 2016-18 on our Condensed Consolidated Statements of Cash Flows was to include restricted cash balances in the beginning and end of period balances of cash, cash equivalents, and restricted cash. The change in restricted cash was previously disclosed in investing activities in the Condensed Consolidated Statements of Cash Flows.

(2) REVENUE

Revenue Recognition

Revenues are recognized in an amount that reflects the consideration we expect to receive in exchange for goods or services, when control of the promised goods or services is transferred to our customers. Our primary types of revenue contracts are:

Regulated natural gas and electric utility services tariffs - Our utilities have regulated operations, as defined by ASC 980, that provide services to regulated customers under rates, charges, terms and conditions of service, and prices determined by the jurisdictional regulators designated for our service territories. Collectively, these rates, charges, terms and conditions are included in a tariff, which governs all aspects of the provision of our regulated services. Our regulated services primarily encompass single performance obligations material to the context of the contract for delivery of either commodity natural gas, commodity electricity, natural gas transportation or electric transmission services. These service revenues are variable based on quantities delivered, influenced by seasonal business and weather patterns. Tariffs are only permitted to be changed through a rate-setting process involving the regulator-empowered statute to establish contractual rates between the utility and its customers. All of our utilities' regulated sales are subject to regulatory-approved tariffs.

Power sales agreements - Our electric utilities and power generation segments have long-term wholesale power sales agreements with other load-serving entities, including affiliates, for the sale of excess power from owned generating units. These agreements include a combination of "take or pay" arrangements, where the customer is obligated to pay for the energy regardless of whether it actually takes delivery, as well as "requirements only" arrangements, where the customer is only obligated to pay for the energy the customer needs. In addition to these long-term contracts, Black Hills also sells excess energy to other load-serving entities on a short-term basis as a member of the Western States Power Pool. The pricing for all of these arrangements is included in the executed contracts or confirmations, reflecting the standalone selling price and is variable based on energy delivered.

Coal supply agreements - Our mining segment sells coal primarily under long-term contracts to utilities for use at their power generating plants, including affiliate electric utilities, and an affiliate non-regulated power generation entity. The contracts include a single promise to supply coal necessary to fuel the customers' facilities during the contract term. The transaction price is established in the coal supply agreements, including cost-based agreements with the affiliated regulated utilities, and is variable based on tons of coal delivered.

Other non-regulated services - Our natural gas and electric utility segments also provide non-regulated services primarily comprised of appliance repair service and protection plans, electric and natural gas technical infrastructure construction and maintenance services, and in Nebraska and Wyoming, an unbundled natural gas commodity offering under the regulatory-approved Choice Gas Program. Revenue contracts for these services generally represent a single performance obligation with the price reflecting the standalone selling price stated in the agreement, and the revenue is variable based on the units delivered or services provided.

The following table depicts the disaggregation of revenue, including intercompany revenue, from contracts with customers by customer type and timing of revenue recognition for each of the reporting segments. Sales tax and other similar taxes are excluded from revenues.

| Three Months Ended March 31, 2018 | Electric Utilities | Gas Utilities | Power Generation | Mining | Inter-company Revenues | Total |
|---|--------------------|---------------|------------------|-----------|------------------------|-------------|
| Customer types: | (in thousands) | | | | | |
| Retail | \$147,057 | \$341,394 | \$ — | \$ 16,557 | \$ (7,842) |) \$497,166 |
| Transportation | — | 41,669 | — | — | (409) |) 41,260 |
| Wholesale | 9,050 | — | 13,933 | — | (12,213) |) 10,770 |
| Market - off-system sales | 4,144 | 427 | — | — | (2,522) |) 2,049 |
| Transmission/Other | 13,071 | 12,670 | — | — | (3,631) |) 22,110 |
| Revenue from contracts with customers | 173,322 | 396,160 | 13,933 | 16,557 | (26,617) |) 573,355 |
| Other revenues | 233 | 1,184 | 9,170 | 571 | (9,124) |) 2,034 |
| Total revenues | \$173,555 | \$397,344 | \$ 23,103 | \$ 17,128 | \$ (35,741) |) \$575,389 |
| Timing of revenue recognition: | | | | | | |
| Services transferred at a point in time | \$— | \$— | \$ — | \$ 16,557 | \$ (7,842) |) \$8,715 |
| Services transferred over time | 173,322 | 396,160 | 13,933 | — | (18,775) |) 564,640 |
| Revenue from contracts with customers | \$173,322 | \$396,160 | \$ 13,933 | \$ 16,557 | \$ (26,617) |) \$573,355 |

The majority of our revenue contracts are based on variable quantities delivered; any fixed consideration contracts with an expected duration of one year or more are immaterial to our consolidated revenues. Variable consideration constraints in the form of discounts, rebates, credits, price concessions, incentives, performance bonuses, penalties or other similar items are not material for our revenue contracts. We are the principal in our revenue contracts, as we have control over the services prior to those services being transferred to the customer.

Revenue Not in Scope of ASC 606

Other revenues included in the table include our revenue accounted for under separate accounting guidance, including lease revenue under ASC 840 and alternative revenue programs revenue under ASC 980. The majority of our lease revenue is related to a 20-year power sale agreement between Colorado IPP and affiliate Colorado Electric. This agreement is accounted for as a direct financing lease whereby Colorado IPP receives revenue for energy delivered and related capacity payments. This lease revenue is eliminated in our consolidated revenues.

Significant Judgments and Estimates

TCJA Revenue Reserve

The TCJA or “tax reform” signed into law on December 22, 2017, reduced the federal corporate income tax rate from 35% to 21% effective for tax years beginning after December 31, 2017. Many of Black Hills’ regulators have directed the utilities to calculate the impact of tax reform on existing customer rates and tariffs caused by the income tax rate reduction. Until the regulators have a chance to review and approve these calculations, the utilities continue to charge customers existing rates with the embedded 35% tax rate, resulting in a reserve to revenue until new rates reflecting the 21% federal tax rate are effective. We estimated and recorded a reserve to revenue of approximately \$15 million during the three months ended March 31, 2018.

Unbilled Revenue

Revenues attributable to natural gas and electricity delivered to customers but not yet billed are estimated and accrued, and the related costs are charged to expense. Factors influencing the determination of unbilled revenues include

estimates of delivered sales volumes based on weather information and customer consumption trends.

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Contract Balances

The nature of our primary revenue contracts provides an unconditional right to consideration upon service delivery; therefore, no customer contract assets or liabilities exist. The unconditional right to consideration is represented by the balance in our Accounts Receivable further discussed in Note 4. We do not typically incur costs that would be capitalized to obtain or fulfill a contract.

Practical Expedients

Our revenue contracts generally provide for performance obligations that are fulfilled and transfer control to customers over time, represent a series of distinct services that are substantially the same, involve the same pattern of transfer to the customer, and provide a right to consideration from our customers in an amount that corresponds directly with the value to the customer for the performance completed to date. Therefore, we recognize revenue in the amount to which we have a right to invoice.

We have revenue contract performance obligations with similar characteristics, and we reasonably expect that the financial statement impact of applying the new revenue recognition guidance to a portfolio of contracts would not differ materially from applying this guidance to the individual contracts or performance obligations within the portfolio. Therefore, we have elected the portfolio approach in applying the new revenue guidance.

(3) BUSINESS SEGMENT INFORMATION

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

| Three Months Ended March 31, 2018 | External Operating Revenue | | Inter-company Operating Revenue | | Total Revenues | Net income (loss) from continuing operations |
|-----------------------------------|----------------------------|----------------|---------------------------------|----------------|----------------|--|
| | Contract Customers | Other Revenues | Contract Customers | Other Revenues | | |
| Segment: | | | | | | |
| Electric | \$ 167,178 | \$ 233 | \$ 6,144 | \$ — | \$ 173,555 | \$ 19,845 |
| Gas ^(a) | 395,742 | 1,184 | 418 | — | 397,344 | 107,620 |
| Power Generation ^(b) | 1,720 | 371 | 12,213 | 8,799 | 23,103 | 5,856 |
| Mining | 8,715 | 246 | 7,842 | 325 | 17,128 | 2,984 |
| Corporate and Other | — | — | — | — | — | (958) |
| Inter-company eliminations | — | — | (26,617) | (9,124) | (35,741) | — |
| Total | \$ 573,355 | \$ 2,034 | \$ — | \$ — | \$ 575,389 | \$ 135,347 |

Under our modified retrospective adoption of ASU 2014-09, revenues for the three months ended March 31, 2017 are not presented by contract type.

| Three Months Ended March 31, 2017 | External Operating Revenue | Inter-company Operating Revenue | Net |
|------------------------------------|----------------------------|---------------------------------|--|
| | | | income (loss) from continuing operations |
| Segment: | | | |
| Electric | \$ 172,170 | \$ 3,854 | \$ 22,230 |
| Gas | 364,901 | 9 | 46,010 |
| Power Generation ^(b) | 2,102 | 21,465 | 6,530 |
| Mining | 8,355 | 8,191 | 2,890 |
| Corporate and Other ^(c) | — | — | 432 |
| Inter-company eliminations | — | (33,519) | — |
| Total | \$ 547,528 | \$ — | \$ 78,092 |

Net income from continuing operations available for common stock for the three months ended March 31, 2018 (a) included a \$49 million tax benefit resulting from legal entity restructuring. See Note 19 of the Notes to Condensed Consolidated Financial Statements for more information.

Net income from continuing operations available for common stock for the three months ended March 31, 2018 (b) and March 31, 2017 reflects net income attributable to noncontrolling interests of \$3.6 million and \$3.5 million, respectively.

Net income (loss) from continuing operations available for common stock for the three months ended March 31, 2017 (c) included a \$1.4 million tax benefit recognized from carryback claims for specified liability losses involving prior tax years.

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: | March 31, 2018 | December 31, 2017 | March 31, 2017 |
| Segment: | | | |
| Electric ^(a) | \$2,890,708 | \$2,906,275 | \$2,872,989 |
| Gas | 3,398,473 | 3,426,466 | 3,260,989 |
| Power Generation ^(a) | 53,323 | 60,852 | 69,737 |
| Mining | 65,568 | 65,455 | 64,973 |
| Corporate activities | 194,193 | 115,612 | 113,143 |
| Discontinued operations | 24,724 | 84,242 | 117,740 |
| Total assets | \$6,626,989 | \$6,658,902 | \$6,499,571 |

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

(4) ACCOUNTS RECEIVABLE

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

| | Accounts Receivable, Trade | Less Unbilled Revenue | Allowance for Doubtful Accounts | Accounts Receivable, net |
|--------------------|----------------------------------|-----------------------------|--|--------------------------------|
| March 31, 2018 | | | | |
| Electric Utilities | \$ 40,492 | \$ 33,907 | \$ (624) | \$ 73,775 |
| Gas Utilities | 120,910 | 60,142 | (3,684) | 177,368 |
| Power Generation | 1,580 | — | — | 1,580 |
| Mining | 3,133 | — | — | 3,133 |
| Corporate | 1,916 | — | — | 1,916 |
| Total | \$ 168,031 | \$ 94,049 | \$ (4,308) | \$ 257,772 |

| | Accounts Receivable, Trade | Less Unbilled Revenue | Allowance for Doubtful Accounts | Accounts Receivable, net |
|--------------------|----------------------------------|-----------------------------|--|--------------------------------|
| December 31, 2017 | | | | |
| Electric Utilities | \$ 39,347 | \$ 36,384 | \$ (586) | \$ 75,145 |
| Gas Utilities | 81,256 | 88,967 | (2,495) | 167,728 |
| Power Generation | 1,196 | — | — | 1,196 |
| Mining | 2,804 | — | — | 2,804 |
| Corporate | 1,457 | — | — | 1,457 |
| Total | \$ 126,060 | \$ 125,351 | \$ (3,081) | \$ 248,330 |

| | Accounts Receivable, Trade | Less Unbilled Revenue | Allowance for Doubtful Accounts | Accounts Receivable, net |
|--|----------------------------------|-----------------------------|--|--------------------------------|
|--|----------------------------------|-----------------------------|--|--------------------------------|

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| March 31, 2017 | Receivable, Trade | Revenue | Doubtful Accounts | Receivable, net |
|--------------------|----------------------|-----------|----------------------|--------------------|
| Electric Utilities | \$ 39,679 | \$ 30,778 | \$ (639) | \$ 69,818 |
| Gas Utilities | 98,027 | 51,926 | (3,646) | 146,307 |
| Power Generation | 1,353 | — | — | 1,353 |
| Mining | 3,197 | — | — | 3,197 |
| Corporate | 1,100 | — | — | 1,100 |
| Total | \$ 143,356 | \$ 82,704 | \$ (4,285) | \$ 221,775 |

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(5) REGULATORY ACCOUNTING

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

| | Maximum Amortization (in years) | March 31, 2018 | December 31, 2017 | March 31, 2017 |
|---|------------------------------------|-------------------|----------------------|-------------------|
| Regulatory assets | | | | |
| Deferred energy and fuel cost adjustments - current ^(a) | 1 | \$25,056 | \$20,187 | \$23,756 |
| Deferred gas cost adjustments ^(a) | 1 | 2,118 | 31,844 | 8,610 |
| Gas price derivatives ^(a) | 3 | 11,045 | 11,935 | 11,520 |
| Deferred taxes on AFUDC ^{(b) (f)} | 45 | 7,808 | 7,847 | 14,976 |
| Employee benefit plans ^(c) | 12 | 109,999 | 109,235 | 109,172 |
| Environmental ^(a) | subject to approval | 1,012 | 1,031 | 1,089 |
| Asset retirement obligations ^(a) | 44 | 521 | 517 | 507 |
| Loss on reacquired debt ^(a) | 28 | 20,267 | 20,667 | 21,866 |
| Renewable energy standard adjustment ^(a) | subject to approval | 1,600 | 1,088 | 963 |
| Deferred taxes on flow through accounting ^{(c) (f)} | 54 | 28,014 | 26,978 | 39,152 |
| Decommissioning costs | 10 | 12,552 | 13,287 | 15,745 |
| Gas supply contract termination ^(a) | 4 | 18,590 | 20,001 | 24,178 |
| Other regulatory assets ^(a) | 30 | 28,650 | 32,837 | 31,055 |
| Total regulatory assets | | 267,232 | 297,454 | 302,589 |
| Less current regulatory assets | | (54,492) | (81,016) | (53,476) |
| Regulatory assets, non-current | | \$212,740 | \$216,438 | \$249,113 |
| Regulatory liabilities | | | | |
| Deferred energy and gas costs ^(a) | 1 | \$20,194 | \$3,427 | \$19,494 |
| Employee benefit plan costs and related deferred taxes ^{(c) (f)} | 12 | 40,332 | 40,629 | 67,973 |
| Cost of removal ^(a) | 44 | 139,002 | 130,932 | 122,548 |
| Excess deferred income taxes ^{(c) (d)} | 40 | 310,622 | 301,553 | 59 |
| TCJA revenue reserve ^(e) | subject to approval | 15,239 | — | — |
| Other regulatory liabilities ^(c) | 25 | 12,472 | 8,585 | 8,582 |
| Total regulatory liabilities | | 537,861 | 485,126 | 218,656 |
| Less current regulatory liabilities | | (42,499) | (6,832) | (22,118) |
| Regulatory liabilities, non-current | | \$495,362 | \$478,294 | \$196,538 |

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

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

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

The increase in the regulatory tax liability is primarily related to the revaluation of deferred income tax balances at the lower income tax rate. As of March 31, 2018 and December 31, 2017, all of the liability was classified as

(d) non-current due to uncertainties around the timing and other regulatory decisions that will affect the amount of regulatory tax liability amortized and returned to customers through rate reductions of other revenue offsets in 2018.

(e) As of March 31, 2018, the amortization periods are yet to be determined and subject to approval by our regulators.

(f) The variance to the prior periods is primarily due to the TCJA.

Regulatory Matters

Except as discussed below, there have been no other significant changes to our Regulatory Matters from those previously disclosed in Note 13 of the Notes to the Consolidated Financial Statements in our 2017 Annual Report on Form 10-K.

TCJA revenue reserve - The TCJA signed into law on December 22, 2017, reduced the federal corporate income tax rate from 35% to 21%. Effective January 1, 2018, the key impact of tax reform on existing utility revenues/tariffs established prior to tax reform results primarily from the change in the federal tax rate from 35% to 21% (including the effects of tax gross-ups not yet approved) affecting current income tax expense embedded in those tariffs. Many of Black Hills' regulators have issued orders directing the utilities to calculate the impacts of tax reform on existing rates/tariffs caused by the income tax rate reduction. Until each regulator has a chance to review and approve the calculations, the utilities continue to charge customers existing rates with the embedded 35% federal tax rate, resulting in a reserve to revenue until new rates reflecting the 21% federal tax rate are effective. We estimated and recorded a reserve to revenue of approximately \$15 million during the three months ended March 31, 2018.

Each of our utilities is working with their respective regulators to address the impact of tax reform and the appropriate benefit to customers.

Rate Review - On April 16, 2018, RMNG received a recommended decision from a Colorado administrative law judge approving a settlement agreement with the Colorado Office of Consumer Counsel and staff on its rate review application previously filed on October 3, 2017. The settlement included \$1.1 million in annual revenue increases and an extension of SSIR to recover costs from 2018 through December 31, 2021. The annual increase is based on a return on equity of 9.9% and a capital structure of 46.63% equity and 53.37% debt. New rates are expected to be effective June 1, 2018 pending approval from the CPUC.

(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:

| | March 31, 2018 | December 31, 2017 | March 31, 2017 |
|--|----------------------|----------------------|----------------------|
| Materials and supplies | \$72,045 | \$69,732 | \$68,202 |
| Fuel - Electric Utilities | 2,903 | 2,962 | 3,433 |
| Natural gas in storage held for distribution | 7,097 | 40,589 | 9,228 |
| Total materials, supplies and fuel | \$82,045 | \$113,283 | \$80,863 |

(7) INVESTMENTS

In February 2018, we contributed \$28 million of assets in exchange for equity securities in a privately held company. The carrying value of our investment in the equity securities was determined using the cost method. We will review this investment on a periodic basis to determine whether a significant event or change in circumstances has occurred that may have an adverse effect on the value of the investment. We estimate that the fair value of this cost method investment approximated or exceeded its carrying value as of March 31, 2018.

The following table presents the carrying value of our investments (in thousands) as of:

| | March 31, 2018 | December 31, 2017 | March 31, 2017 |
|------------------------|----------------------|----------------------|----------------------|
| Cost method investment | \$28,100 | \$— | \$— |

| | | | |
|----------------------|----------|-----------|----------|
| Cash surrender value | 12,827 | 13,090 | 12,712 |
| Total investments | \$40,927 | \$ 13,090 | \$12,712 |

(8) 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 March 31, | |
|---------------------------------------|---------------------------------|-----------|
| | 2018 | 2017 |
| Net income available for common stock | \$ 133,004 | \$ 76,523 |
| Weighted average shares - basic | 53,319 | 53,152 |
| Dilutive effect of: | | |
| Equity Units ^(a) | 733 | 1,595 |
| Equity compensation | 70 | 185 |
| Weighted average shares - diluted | 54,122 | 54,932 |

(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 March 31, | |
|----------------------|---------------------------------------|------|
| | 2018 | 2017 |
| Equity compensation | 71 | — |
| Anti-dilutive shares | 71 | — |

(9) NOTES PAYABLE AND CURRENT MATURITIES

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

| | March 31, 2018 | | December 31, 2017 | | March 31, 2017 | |
|---------------------------|------------------------|-------------------------|------------------------|-------------------------|------------------------|-------------------------|
| | Balance Outstanding | Letters of Credit | Balance Outstanding | Letters of Credit | Balance Outstanding | Letters of Credit |
| Revolving Credit Facility | \$— | \$ 15,830 | \$— | \$ 26,848 | \$— | \$ 28,100 |
| CP Program | 164,200 | — | 211,300 | — | 50,950 | — |
| Total | \$ 164,200 | \$ 15,830 | \$ 211,300 | \$ 26,848 | \$ 50,950 | \$ 28,100 |

Revolving Credit Facility and CP Program

Our \$750 million corporate Revolving Credit Facility extends through August 9, 2021 with two one-year extension options (subject to consent from lenders). This facility 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 are 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 March 31, 2018. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

We have 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 three months ended March 31, 2018 and our notes outstanding as of March 31, 2018 were \$164 million. As of March 31, 2018, the weighted average interest rate on CP Program borrowings was 2.34%.

Debt Covenants

Our Revolving Credit Facility and term loan agreements allow for the exclusion of the Remarketable Junior Subordinated Notes (RSNs) from our Consolidated Indebtedness to Capitalization Ratio covenant calculation. Under our 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 Term Loans require compliance with the following financial covenant at the end of each quarter:

| | As of March 31, 2018 | Covenant Requirement |
|---|----------------------|----------------------|
| Consolidated Indebtedness to Capitalization Ratio | 59% | Less than 65% |

As of March 31, 2018, we were in compliance with this covenant.

Current Maturities

As of March 31, 2018, our \$250 million Senior unsecured notes due January 11, 2019 and \$5.7 million of principal due in the next twelve months on our Corporate term loan due June 7, 2021 are classified as Current maturities of long-term debt.

(10) EQUITY

A summary of the changes in equity is as follows:

| Three Months Ended March 31, 2018 | Total Stockholders' Equity | Noncontrolling Interest | Total Equity |
|---|----------------------------|-------------------------|--------------|
| | (in thousands) | | |
| Balance at December 31, 2017 | \$ 1,708,974 | \$ 111,232 | \$ 1,820,206 |
| Net income (loss) | 133,004 | 3,630 | 136,634 |
| Other comprehensive income (loss) | 1,260 | — | 1,260 |
| Dividends on common stock | (25,444) | — | (25,444) |
| Share-based compensation | 755 | — | 755 |
| Issuance of common stock | — | — | — |
| Dividend reinvestment and stock purchase plan | 219 | — | 219 |
| Other | 2 | — | 2 |
| Distribution to noncontrolling interest | — | (5,648) | (5,648) |
| Balance at March 31, 2018 | \$ 1,818,770 | \$ 109,214 | \$ 1,927,984 |

| Three Months Ended March 31, 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) | 76,523 | 3,516 | 80,039 |
| Other comprehensive income (loss) | 1,153 | — | 1,153 |
| Dividends on common stock | (23,754) |)— | (23,754) |
| Share-based compensation | 2,392 | — | 2,392 |
| Dividend reinvestment and stock purchase plan | 748 | — | 748 |
| Redeemable noncontrolling interest | (1,096) |)— | (1,096) |
| Cumulative effect of ASU 2016-09 implementation | 3,714 | — | 3,714 |
| Other stock transactions | (3) |)— | (3) |
| Distribution to noncontrolling interest | — | (4,349) | (4,349) |
| Balance at March 31, 2017 | \$ 1,674,316 | \$ 114,662 | \$ 1,788,978 |

At-the-Market Equity Offering Program

On August 4, 2017, we renewed our ATM equity offering program which reset the size of the program to an aggregate value of up to \$300 million. The renewed program, which allows us to sell shares of our common stock, is the same as the prior program other than the aggregate value increased from \$200 million to \$300 million. The shares may be offered from time to time pursuant to a sales agreement dated August 4, 2017. 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 three months ended March 31, 2018 and March 31, 2017 under the ATM equity offering program.

Noncontrolling Interest

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 Colorado IPP to a third-party buyer. 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.

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 Colorado IPP's economic performance. Black Hills Electric Generation, as the primary beneficiary, continues to consolidate Colorado IPP. Colorado IPP has not received financial or other support from the Company outside of pre-existing contractual arrangements during the reporting period. 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 Condensed Consolidated Balance Sheets related to the VIE described above as of:

| | March 31, 2018 | December 31, 2017 | March 31, 2017 |
|--|-------------------|----------------------|-------------------|
| | (in thousands) | | |
| Assets | | | |
| Current assets | \$12,567 | \$14,837 | \$12,167 |
| Property, plant and equipment of variable interest entities, net | \$205,725 | \$208,595 | \$217,083 |

Liabilities

| | | | |
|---------------------|---------|---------|---------|
| Current liabilities | \$3,404 | \$4,565 | \$3,464 |
|---------------------|---------|---------|---------|

(11) 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 2017 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 retail natural gas marketing activities and our fuel procurement for certain gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt.

Credit Risk

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

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

We perform ongoing credit evaluations of our customers and adjust credit limits based 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 12.

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, over-the-counter 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.

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 April 2018 through May 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 inception of the hedge, upon occurrence of a triggering event

and as of the end of each quarter.

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:

| | March 31, 2018 | | December 31, 2017 | | March 31, 2017 | |
|--|----------------------|--|----------------------|--|----------------------|--|
| | Notional (MMBtus) | Maximum Term (months) ^(a) | Notional (MMBtus) | Maximum Term (months) ^(a) | Notional (MMBtus) | Maximum Term (months) ^(a) |
| Natural gas futures purchased | 6,760,000 | 33 | 8,330,000 | 36 | 12,330,000 | 45 |
| Natural gas options purchased, net | 170,000 | 11 | 3,540,000 | 14 | 500,000 | 21 |
| Natural gas basis swaps purchased | 6,770,000 | 33 | 8,060,000 | 36 | 11,230,000 | 45 |
| Natural gas over-the-counter swaps, net ^(b) | 2,760,000 | 26 | 3,820,000 | 29 | 3,165,952 | 26 |
| Natural gas physical contracts, net ^(c) | 386,250 | 32 | 12,826,605 | 35 | 3,015,234 | 12 |

(a) Term reflects the maximum forward period hedged.

(b) As of March 31, 2018, 675,000 MMBtus were designated as cash flow hedges for the natural gas over-the-counter swaps purchased.

(c) Volumes exclude contracts that qualify for the normal purchase, normal sales exception.

Based on March 31, 2018 prices, a \$0.4 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

At March 31, 2018, we had no outstanding interest rate swap agreements. Our last interest rate swap agreement with a \$50 million notional value, which was designated to borrowings on our Revolving Credit Facility, expired in January 2017.

Discontinued Operations

Our Oil and Gas segment was exposed to risks associated with changes in the market prices of oil and gas. Through December 2017, we used exchange traded futures, swaps and options to hedge portions of our crude oil and natural gas production to mitigate commodity price risk and preserve cash flows. Hedge accounting was elected on the swaps and futures contracts. These transactions were designated upon inception as cash flow hedges, documented under accounting standards for derivatives and hedging and initially met prospective effectiveness testing. As a result of divesting our Oil and Gas assets, these activities were discontinued and there were no outstanding derivative agreements as of March 31, 2018 or December 31, 2017. At March 31, 2017, we had outstanding crude oil futures and swap contracts with notional volumes of 90,000 Bbls, crude oil option contracts with notional volumes of 27,000 Bbls and natural gas futures and swap contracts with notional volumes of 1,890,000 MMBtus.

Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income is presented below for the three months ended March 31, 2018 and 2017 (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 March 31, 2018

| Location of | Amount of | Location of |
|-------------|-----------|-------------|
|-------------|-----------|-------------|

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| Derivatives in Cash Flow Hedging Relationships | Reclassifications from AOCI into Income | Gain/(Loss) Reclassified from AOCI into Income (Settlements) | 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 | Fuel, purchased power and cost of natural gas sold | (621) | Fuel, purchased power and cost of natural gas sold | — |
| Total | | \$ (1,334) | | \$ — |

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Three Months Ended March 31, 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 | \$ (712) | Interest expense | \$ — |
| Commodity derivatives | Net (loss) from discontinued operations | 229 | Net (loss) from discontinued operations | — |
| Commodity derivatives | Fuel, purchased power and cost of natural gas sold | 58 | Fuel, purchased power and cost of natural gas sold | — |
| Total | | \$ (425) | | \$ — |

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 months ended March 31, 2018 and 2017. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts, if any, are immediately recognized in the Condensed Consolidated Statements of Income as incurred.

| | Three Months Ended March 31, | |
|---|------------------------------|---------|
| | 2018 | 2017 |
| | (In thousands) | |
| Increase (decrease) in fair value: | | |
| Interest rate swaps | \$— | \$90 |
| Forward commodity contracts | (297) | 926 |
| Recognition of (gains) losses in earnings due to settlements: | | |
| Interest rate swaps | 713 | 712 |
| Forward commodity contracts | 621 | (287) |
| Total other comprehensive income (loss) from hedging | \$1,037 | \$1,441 |

Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Condensed Consolidated Statements of Income for the three months ended March 31, 2018 and 2017 (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.

| Derivatives Not Designated as Hedging Instruments | Location of Gain/(Loss) on Derivatives Recognized in Income | Three Months Ended March 31, | |
|---|---|------------------------------|-----------------------|
| | | 2018 | 2017 |
| | | Amount of Gain/(Loss) | Amount of Gain/(Loss) |
| | | Recognized in Income | Recognized in Income |
| Commodity derivatives | Net (loss) from discontinued operations | \$— | \$ 117 |
| Commodity derivatives | Fuel, purchased power and cost of natural gas sold | 254 | (809) |
| | | \$254 | \$ (692) |

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 or Regulatory liabilities. The net unrealized losses included in our Regulatory assets or Regulatory liability accounts related to the hedges in our Utilities were \$11 million, \$12 million and \$12 million at March 31, 2018, December 31, 2017 and March 31, 2017, respectively.

(12) 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 2017 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

Discontinued Operations:

Oil and gas derivative instruments are included in assets and liabilities held for sale discussed in Note 18.

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Utilities Segments:

The commodity contracts for our Utilities Segments, are valued using the market approach and 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 March 31, 2018, we no longer have derivatives within our corporate activities as our last interest rate swaps matured in January 2017.

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.

Oil and gas derivative instruments are included in assets and liabilities held for sale discussed in Note 18. 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 March 31, 2018 | | | |
|-----------------------------------|----------------------|---------|-------------|--|
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty Netting |
| | | | | Total |
| (in thousands) | | | | |
| Assets: | | | | |
| Commodity derivatives — Utilities | \$414 | \$ | —\$ (119 |) \$295 |
| Total | \$414 | \$ | —\$ (119 |) \$295 |
| Liabilities: | | | | |
| Commodity derivatives — Utilities | \$12,259 | \$ | —\$ (11,175 |) \$1,084 |
| Total | \$12,259 | \$ | —\$ (11,175 |) \$1,084 |

| | As of December 31, 2017 | | | |
|--|-------------------------|---------|---------|----------------------------------|
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty |
| | | | | Total |
| | | | | |

Netting

(in thousands)

Assets:

| | | | | | |
|-----------------------------------|------------|----|------------|---|-------|
| Commodity derivatives — Utilities | \$ \$1,586 | \$ | —\$ (1,282 |) | \$304 |
| Total | \$ \$1,586 | \$ | —\$ (1,282 |) | \$304 |

Liabilities:

| | | | | | |
|-----------------------------------|-------------|----|-------------|---|---------|
| Commodity derivatives — Utilities | \$ \$13,756 | \$ | —\$ (11,497 |) | \$2,259 |
| Total | \$ \$13,756 | \$ | —\$ (11,497 |) | \$2,259 |

| As of March 31, 2017 | | | | | |
|-----------------------------------|---------|---------|---------|--|-------|
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty Netting | Total |
| (in thousands) | | | | | |
| Assets: | | | | | |
| Commodity derivatives — Utilities | \$2,642 | \$ | — | \$(1,651) | \$991 |
| Total | \$2,642 | \$ | — | \$(1,651) | \$991 |

| | | | | | |
|-----------------------------------|----------|----|---|------------|-------|
| Liabilities: | | | | | |
| Commodity derivatives — Utilities | \$13,139 | \$ | — | \$(12,933) | \$206 |
| Total | \$13,139 | \$ | — | \$(12,933) | \$206 |

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 March 31, 2018

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|--|--|---------------------------------------|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative liabilities — current | \$ — | \$ 394 |
| Commodity derivatives | Other deferred credits and other liabilities | — | 29 |
| Total derivatives designated as hedges | | \$ — | \$ 423 |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$ 295 | \$ — |
| Commodity derivatives | Derivative liabilities — current | — | 497 |
| Commodity derivatives | Other deferred credits and other liabilities | — | 164 |
| Total derivatives not designated as hedges | | \$ 295 | \$ 661 |

As of December 31, 2017

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|--|--|---------------------------------------|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative liabilities — current | \$ — | \$ 817 |
| Commodity derivatives | Other deferred credits and other liabilities | — | 67 |
| Total derivatives designated as hedges | | \$ — | \$ 884 |

Derivatives not designated as hedges:

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| | | | |
|--|--|--------|----------|
| Commodity derivatives | Derivative assets — current | \$ 304 | \$ — |
| Commodity derivatives | Derivative liabilities — current | — | 1,264 |
| Commodity derivatives | Other deferred credits and other liabilities | — | 111 |
| Total derivatives not designated as hedges | | \$ 304 | \$ 1,375 |

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As of March 31, 2017

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|--|--|---------------------------------------|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$ 163 | \$ — |
| Commodity derivatives | Current assets held for sale | 559 | — |
| Commodity derivatives | Derivative liabilities — current | — | 12 |
| Commodity derivatives | Other deferred credits and other liabilities | — | 26 |
| Commodity derivatives | Current liabilities held for sale | — | 293 |
| Commodity derivatives | Noncurrent liabilities held for sale | — | 45 |
| Total derivatives designated as hedges | | \$ 722 | \$ 376 |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$ 819 | \$ — |
| Commodity derivatives | Other assets, non—current | 9 | — |
| Commodity derivatives | Derivative liabilities — current | — | 63 |
| Commodity derivatives | Other deferred credits and other liabilities | — | 105 |
| Commodity derivatives | Current liabilities held for sale | — | 96 |
| Total derivatives not designated as hedges | | \$ 828 | \$ 264 |

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 2017 Annual Report on Form 10-K.

(13) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 12, were as follows (in thousands) as of:

| | March 31, 2018 | | December 31, 2017 | | March 31, 2017 | |
|---|--------------------|-------------|--------------------|-------------|--------------------|-------------|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash and cash equivalents ^(a) | \$30,947 | \$30,947 | \$15,420 | \$15,420 | \$11,291 | \$11,291 |
| Restricted cash ^(a) | \$2,958 | \$2,958 | \$2,820 | \$2,820 | \$2,409 | \$2,409 |
| Notes payable ^(b) | \$164,200 | \$164,200 | \$211,300 | \$211,300 | \$50,950 | \$50,950 |
| Long-term debt, including current maturities ^{(c) (d)} | \$3,114,530 | \$3,265,965 | \$3,115,143 | \$3,350,544 | \$3,216,473 | \$3,388,809 |

^(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.

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.

^(d) Carrying amount of long-term debt is net of deferred financing costs.

(14) 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 Condensed Consolidated Statements of Income for the period, net of tax (in thousands):

| | Location on the Condensed Consolidated Statements of Income | Amount Reclassified from AOCI Three Months Ended | |
|---|---|--|----------------|
| | | March 31, 2018 | March 31, 2017 |
| Gains and (losses) on cash flow hedges: | | | |
| Interest rate swaps | Interest expense | \$(713) | \$(712) |
| Commodity contracts | Net (loss) from discontinued operations | — | 229 |
| Commodity contracts | Fuel, purchased power and cost of natural gas sold | (621) | 58 |
| | | (1,334) | (425) |
| Income tax | Income tax benefit (expense) | 297 | 143 |
| Total reclassification adjustments related to cash flow hedges, net of tax | | \$(1,037) | \$(282) |
| Amortization of components of defined benefit plans: | | | |
| Prior service cost | Operations and maintenance | \$45 | \$48 |
| Actuarial gain (loss) | Operations and maintenance | (622) | (414) |
| | | (577) | (366) |
| Income tax | Income tax benefit (expense) | 126 | 137 |
| Total reclassification adjustments related to defined benefit plans, net of tax | | \$(451) | \$(229) |
| Total reclassifications | | \$(1,488) | \$(511) |

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, 2017 | \$(19,581) | \$ (518) | \$ (21,103) | \$(41,202) |
| Other comprehensive income (loss) before reclassifications | — | (228) | — | (228) |
| Amounts reclassified from AOCI | 561 | 476 | 451 | 1,488 |
| Reclassifications of certain tax effects from AOCI | 15 | — | 3 | 18 |
| Ending Balance March 31, 2018 | \$(19,005) | \$ (270) | \$ (20,649) | \$(39,924) |

| | Derivatives Designated as Cash Flow Hedges | | | |
|---|--|--------------------------|------------------------------|------------|
| | Interest Rate Swaps | Commodity Derivatives | Employee Benefit Plans | Total |
| Balance as of December 31, 2016 | \$(18,109) | \$ (233) | \$ (16,541) | \$(34,883) |
| Other comprehensive income (loss) before reclassifications | 58 | 584 | — | 642 |
| Amounts reclassified from AOCI | 463 | (181) | 229 | 511 |
| Ending Balance March 31, 2017 | \$(17,588) | \$ 170 | \$ (16,312) | \$(33,730) |

(15) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

| Three Months Ended | March 31, March 31, 2018 2017 (in thousands) | |
|---|--|------------|
| Non-cash investing and financing activities— | | |
| Property, plant and equipment acquired with accrued liabilities | \$21,708 | \$26,532 |
| Cash (paid) refunded during the period — | | |
| Interest (net of amounts capitalized) | \$(36,928) | \$(36,418) |
| Income taxes (paid) refunded | \$ (14,336) | \$ 13 |

(16) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plan

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

| | Three Months Ended March 31, | |
|--------------------------------|------------------------------------|---------|
| | 2018 | 2017 |
| Service cost | \$1,708 | \$1,758 |
| Interest cost | 3,867 | 3,880 |
| Expected return on plan assets | (6,185) | (6,129) |
| Prior service cost | 15 | 14 |
| Net loss (gain) | 2,158 | 1,002 |
| Net periodic benefit cost | \$1,563 | \$525 |

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 March 31, | |
|--------------------------------|------------------------------------|---------|
| | 2018 | 2017 |
| Service cost | \$573 | \$575 |
| Interest cost | 521 | 533 |
| Expected return on plan assets | (57) | (79) |
| Prior service cost (benefit) | (99) | (109) |
| Net loss (gain) | 54 | 125 |
| Net periodic benefit cost | \$992 | \$1,045 |

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 March 31, | |
|---------------------------|---------------------------------------|---------|
| | 2018 | 2017 |
| Service cost | \$280 | \$827 |
| Interest cost | 293 | 319 |
| Prior service cost | — | 1 |
| Net loss (gain) | 250 | 250 |
| Net periodic benefit cost | \$823 | \$1,397 |

For the three months ended March 31, 2018, service costs were recorded in Operations and maintenance expense while non-service costs were recorded in Other income (expense), net, on the Condensed Consolidated Statements of Income. For the three months ended March 31, 2017, service costs and non-service costs were recorded in Operations

and maintenance expense. Because prior years' costs were not considered material, they were not reclassified on the Condensed Consolidated Statements of Income. See Note 1 for additional information.

Contributions

Contributions to the Defined Benefit Pension Plan are cash contributions made directly to the Pension Plan Trust account. Contributions to the Postretirement Healthcare and Supplemental Plans are made in the form of benefit payments. Contributions made in 2018 and anticipated contributions for 2018 and 2019 are as follows (in thousands):

| | Contributions Made Three Months Ended March 31, 2018 | Additional Contributions Anticipated for 2018 | Contributions Anticipated for 2019 |
|---|--|--|---------------------------------------|
| Defined Benefit Pension Plan | \$ — | \$ 12,700 | \$ 12,700 |
| Non-pension Defined Benefit Postretirement Healthcare Plans | \$ 1,234 | \$ 3,702 | \$ 4,802 |
| Supplemental Non-qualified Defined Benefit and Defined Contribution Plans | \$ 343 | \$ 1,029 | \$ 1,921 |

(17) 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 2017 Annual Report on Form 10-K.

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 March 31, 2018, 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 March 31, 2018, the restricted net assets at our Electric Utilities and Gas Utilities were approximately \$257 million.

(18) DISCONTINUED OPERATIONS

Results of operations for discontinued operations have been classified as Loss from discontinued operations, net of income taxes in the accompanying Condensed Consolidated Statements of Income. Current assets, noncurrent assets, current liabilities and non-current liabilities of the discontinued operations have been reclassified and reflected on the accompanying Condensed Consolidated Balance Sheets as “Current assets held for sale,” “Noncurrent assets held for sale,” “Current liabilities held for sale,” and “Noncurrent liabilities held for sale”, respectively. Prior periods relating to our discontinued operations have also been reclassified to reflect consistency within our condensed consolidated financial

statements.

Oil and Gas Segment

On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. As of May 4, 2018, we have executed agreements to sell or we have closed on sales transactions for approximately 96% of our oil and gas properties. We expect to execute agreements to sell all remaining assets, transfer associated liabilities, and settle substantially all remaining liabilities by mid-year 2018.

In the process of divesting our Oil and Gas segment, we performed a fair value assessment of the assets and liabilities classified as held for sale. We evaluated our disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. The market approach was based on our recent fourth quarter 2017 sale of our Powder River Basin assets and pending sale transactions of our other properties.

There is risk involved when determining the fair value of assets, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In

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addition, the fair value of the assets and liabilities could be different using different estimates and assumptions in the valuation techniques used. We believe that the estimates used in calculating the fair value of our assets and liabilities held for sale are reasonable based on the information that was known when the estimates were made and how they compared with the additional property sales occurring in the first quarter of 2018.

At December 31, 2017, the fair value of our held for sale assets was less than our carrying value, which required an after-tax write down of \$13 million. There were no further adjustments made to the fair value of our held for sale assets at March 31, 2018.

Total assets and liabilities of BHEP at March 31, 2018 and December 31, 2017 have been classified as Current assets held for sale and Current liabilities held for sale on the accompanying Condensed Consolidated Balance Sheets due to the expected final disposals occurring by mid-year 2018. Held for sale assets and liabilities at March 31, 2017 are classified as current and non-current.

| (in thousands) | As of March 31, 2018 | December 31, 2017 | March 31, 2017 |
|--|-------------------------------|----------------------|-------------------|
| Other current assets | \$4,332 | \$10,360 | \$9,112 |
| Derivative assets, current and noncurrent | — | — | 559 |
| Deferred income tax assets, noncurrent, net | 3,739 | 16,966 | 23,722 |
| Property, plant and equipment, net | 16,653 | 56,916 | 84,347 |
| Other current liabilities | (17,233) | (18,966) | (7,589) |
| Derivative liabilities, current and noncurrent | — | — | (434) |
| Other noncurrent liabilities | (7,677) | (22,808) | (23,150) |
| Net assets (liabilities) | \$(186) | \$42,468 | \$86,567 |

At March 31, 2018, December 31, 2017 and March 31, 2017, the Oil and Gas segment's net deferred tax assets were primarily comprised of basis differences on oil and gas properties, which are settled when their related properties are sold.

BHEP's accrued liabilities at March 31, 2018 and December 31, 2017 consisted primarily of a liability contingent on final approval from the Bureau of Indian Affairs on the Jicarilla property sale, accrued royalties, payroll and property taxes. Current liabilities at March 31, 2017 consisted primarily of accrued royalties, payroll and property taxes. Other liabilities at March 31, 2018, December 31, 2017 and March 31, 2017 consisted primarily of asset retirement obligations relating to plugging and abandonment of oil and gas wells.

Operating results of the Oil and Gas segment included in Discontinued operations on the accompanying Condensed Consolidated Statements of Income were as follows (in thousands):

| | Three Months Ended March 31, 2018 2017 (in thousands) | |
|--|--|-----------|
| Revenue | \$3,915 | \$6,475 |
| Operations and maintenance | 5,901 | 7,205 |
| Depreciation, depletion and amortization | 1,300 | 1,945 |
| Total operating expenses | 7,201 | 9,150 |
| Operating (loss) | (3,286) | (2,675) |
| Other income (expense), net | 29 | 73 |
| Income tax benefit (expense) | 914 | 1,033 |
| (Loss) from discontinued operations | \$(2,343) | \$(1,569) |

(19) INCOME TAXES

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

| | Three Months Ended March 31, 2018 2017 | |
|---|---|--------|
| Tax (benefit) expense | 21.0 % | 35.0 % |
| Federal statutory rate | 2.0 | 1.4 |
| State income tax (net of federal tax effect) | (0.2) | (0.4) |
| Percentage depletion in excess of cost | (0.7) | (1.1) |
| Noncontrolling interest | — | (1.7) |
| IRC 172(f) carryback claim ^(a) | (1.3) | (1.2) |
| Tax credits | (2.1) | (2.4) |
| Effective tax rate adjustment | (0.4) | — |
| Flow-through adjustments | 2.0 | — |
| TCJA change in estimate ^(b) | (43.7) | — |
| Tax benefit related to legal restructuring ^(c) | 0.6 | — |
| Other tax differences | (22.8)% | 29.6 % |

During the first quarter of 2017, the Company filed amended income tax returns for the years 2006 through 2008 to carryback specified liability losses in accordance with IRC 172(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.

The TCJA was signed into law on December 22, 2017. In accordance with ASC 740, net deferred tax assets and liabilities were revalued as of December 31, 2017 due to the reduction in the federal income tax rate from 35% to 21%. During the three months ended March 31, 2018, certain estimated items associated with the revaluation have been updated.

(c)

Tax benefit from legal restructuring associated with amortizable goodwill as part of ongoing jurisdictional simplification.

Tax benefit related to legal restructuring

As part of the Company's ongoing efforts to continue to integrate the legal entities that the Company has acquired in recent years, certain legal entity restructuring transactions occurred on March 31, 2018. As a result of these transactions, additional deferred income tax assets of \$49 million, related to goodwill that is amortizable for tax purposes, were recorded and deferred tax benefits of \$49 million were recorded to income tax benefit (expense) on the Condensed Consolidated Statements of Income. Due to this being a common control transaction, it had no effect on the other assets and liabilities of these entities.

TCJA

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. The Company remeasured deferred income taxes at the 21% federal tax rate as of December 31, 2017. The entities subject to regulatory construct have made their best estimate regarding the probability of settlements of net regulatory liabilities established pursuant to the TCJA. The amount of the settlements may change based on decisions and actions by the rate regulators, which could have a material impact on the Company's future results of operations, cash flows or financial position. We revalued our deferred tax assets and liabilities as of December 31, 2017, which reflected our estimate of the impact of the TCJA. We will continue to evaluate subsequent regulations, clarifications and interpretations with the assumptions made, which could materially change our estimate.

(20) ACCRUED LIABILITIES

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

| | March 31, 2018 | December 31, 2017 | March 31, 2017 |
|--|-------------------|----------------------|-------------------|
| Accrued employee compensation, benefits and withholdings | \$46,262 | \$52,467 | \$46,410 |
| Accrued property taxes | 42,912 | 42,029 | 39,134 |
| Customer deposits and prepayments | 35,748 | 44,420 | 41,135 |
| Accrued interest and contract adjustment payments | 30,426 | 33,822 | 30,488 |
| CIAC current portion | 1,552 | 1,552 | 1,575 |
| Other (none of which is individually significant) | 37,140 | 45,172 | 37,834 |
| Total accrued liabilities | \$194,040 | \$219,462 | \$196,576 |

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 210,000 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 1,042,000 natural gas customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as available basis.

Our Gas Utilities also provide non-regulated services through Black Hills Energy Services. Black Hills Energy Services provides approximately 52,000 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 conditioning, heating and water-heating equipment, and provide associated repair service and protection plans under various trade names. Service Guard and CAPP provide appliance repair services to approximately 63,000 and 31,000 residential customers, respectively, through Company technicians and third-party service providers, typically through on-going monthly service agreements. Tech Services 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.

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. All of our non-utility business segments support our utilities. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

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 months ended March 31, 2018 and 2017, and our financial condition as of March 31, 2018, December 31, 2017 and March 31, 2017, 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 55.

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 March 31, 2018 Compared to Three Months Ended March 31, 2017. Net income from continuing operations available for common stock for the three months ended March 31, 2018 was \$135 million, or \$2.50 per diluted share, compared to \$78 million, or \$1.42 per diluted share, reported for the same period in 2017. The variance to the prior year included the following:

Gas Utilities' earnings increased \$62 million primarily due to the recognition of a deferred tax benefit of \$49 million resulting from legal entity restructuring associated with amortizable goodwill for tax purposes; earnings also benefited from colder winter weather;

Electric Utilities' earnings decreased \$2.4 million driven primarily by higher operating expenses, partially offset by colder weather;

Corporate and other expenses increased \$1.4 million primarily due to higher tax benefits recognized in the prior year, partially offset by a reduction in corporate operating expenses; and

Power Generation's earnings decreased \$0.7 million primarily due to lower MWh sold and higher operating expenses.

Net income available for common stock for the three months ended March 31, 2018 was \$133 million, or \$2.46 per diluted share, compared to \$77 million, or \$1.39 per diluted share reported for the same period in 2017. (Loss) from discontinued operations for the three months ended March 31, 2018 was \$(2.3) million, or \$(0.04) per diluted share compared to \$(1.6) million or \$(0.03) per diluted share reported for the same period in 2017.

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

| | Three Months Ended March 31, | | |
|---|------------------------------|-----------|------------|
| | 2018 | 2017 | Variance |
| Revenue | | | |
| Revenue | \$611,130 | \$581,047 | \$30,083 |
| Inter-company eliminations | (35,741) | (33,519) | (2,222) |
| | \$575,389 | \$547,528 | \$27,861 |
| Net income (loss) from continuing operations available for common stock | | | |
| Electric Utilities ^(b) | \$19,845 | \$22,230 | \$(2,385) |
| Gas Utilities ^(a) | 107,620 | 46,010 | 61,610 |
| Power Generation ^(b) | 5,856 | 6,530 | (674) |
| Mining ^(b) | 2,984 | 2,890 | 94 |
| | 136,305 | 77,660 | 58,645 |
| Corporate and Other ^(b) | (958) | 432 | (1,390) |
| Net income from continuing operations | 135,347 | 78,092 | 57,255 |
| (Loss) from discontinued operations, net of tax | (2,343) | (1,569) | (774) |
| Net income available for common stock | \$133,004 | \$76,523 | \$56,481 |

Net income (loss) from continuing operations for the three months ended March 31, 2018 included a \$49 million (a) tax benefit resulting from legal entity restructuring. See Note 19 of the Notes to Condensed Consolidated Financial Statements for more information.

(b) Net income (loss) from continuing operations for the three months ended March 31, 2018 included approximately \$2.3 million of income tax expense recorded primarily as a result of an increase to a valuation allowance associated with tax reform related changes in estimated future taxable income. The impact to our operating segments and

Corporate and Other was: Electric Utilities \$0.4 million; Mining \$0.5 million; Power Generation \$0.7 million; and Corporate and Other \$0.7 million.

Overview of Business Segments and Corporate Activity

Electric Utilities Segment

Electric Utilities experienced colder winter weather during the three months ended March 31, 2018 compared to the three months ended March 31, 2017. Heating degree days for the three months ended March 31, 2018 were 1% higher than normal compared to 11% lower than normal for the same period in 2017.

On April 25, 2018, Colorado Electric received approval from the CPUC to contract with Black Hills Electric Generation to purchase 60 megawatts of wind energy through a 25-year power purchase agreement. This renewable energy will enable Colorado Electric to comply with Colorado's Renewable Energy Standard.

During the first quarter of 2018, South Dakota Electric commenced construction of a \$70 million, 230-kV, 175 mile-long transmission line that connects Rapid City, South Dakota to Stegall, Nebraska. The project will be constructed in two segments, with the first segment expected to be placed in service in 2018 and the second segment expected to be serving customers in 2019.

Gas Utilities Segment

As part of the Company's ongoing efforts to continue to integrate the legal entities that the Company has acquired in recent years, certain legal entity restructuring transactions occurred on March 31, 2018. As a result of these transactions, additional deferred income tax assets of \$49 million, related to goodwill that is amortizable for tax purposes, were recorded and deferred tax benefits of \$49 million were recorded to income tax benefit (expense) on the Condensed Consolidated Statements of Income.

On April 16, 2018, RMNG received a recommended decision from a Colorado administrative law judge approving a settlement agreement with the Colorado Office of Consumer Counsel and staff on its rate review application previously filed on October 3, 2017. The settlement included \$1.1 million in annual revenue increases and an extension of SSIR to recover costs from 2018 through December 31, 2021. The annual increase is based on a return on equity of 9.9% and a capital structure of 46.63% equity and 53.37% debt. New rates are expected to be effective June 1, 2018, pending approval from the CPUC.

Gas Utilities experienced colder winter weather during the three months ended March 31, 2018 compared to the three months ended March 31, 2017. Heating degree days for the three months ended March 31, 2018 were 2% higher than normal compared to 13% lower than normal for the same period in 2017.

Power Generation

On April 25, 2018 Black Hills Electric Generation was selected to provide renewable energy to Colorado Electric from a new 60-megawatt wind project. The \$71 million Busch Ranch II wind project is expected to be in service by the end of 2019.

Corporate and Other

On March 8, 2018, S&P affirmed Black Hills' credit rating at BBB and revised the outlook to Positive.

Discontinued Operations

On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. As of May 4, 2018, we have executed agreements to sell or we have closed on sales transactions for approximately 96% of our oil and gas properties. We expect to execute agreements to sell all remaining assets by mid-year 2018. See Note 18 of the Notes to Condensed Consolidated Financial Statements for more information.

Operating Results

A discussion of operating results from our segments and Corporate activities follows. Revenues for operating segments in the following sections are presented in total and by retail class. For disaggregation of revenue by contract type and operating segment, see Note 2 of the Notes to Condensed Consolidated Financial Statements for more information.

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 March 31, | | |
|--------------------------------|---------------------------------|-----------|-----------|
| | 2018 | 2017 | Variance |
| | (in thousands) | | |
| Revenue | \$173,555 | \$176,024 | \$(2,469) |
| Total fuel and purchased power | 67,123 | 68,400 | (1,277) |
| Gross margin | 106,432 | 107,624 | (1,192) |
| Operations and maintenance | 45,093 | 40,783 | 4,310 |
| Depreciation and amortization | 24,513 | 22,861 | 1,652 |
| Total operating expenses | 69,606 | 63,644 | 5,962 |
| Operating income | 36,826 | 43,980 | (7,154) |
| Interest expense, net | (13,291) | (13,412) | 121 |
| Other income (expense), net | (181) | 340 | (521) |
| Income tax benefit (expense) | (3,509) | (8,678) | 5,169 |
| Net income | \$19,845 | \$22,230 | \$(2,385) |

Results of Operations for the Electric Utilities for the Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017: Net income from continuing operations available for common stock for the Electric Utilities was \$20 million for the three months ended March 31, 2018, compared to Net income from continuing operations available for common stock of \$22 million for the three months ended March 31, 2017, as a result of:

Gross margin decreased primarily due to a \$6.1 million reserve to revenue to reflect the lower federal income tax rate from the TCJA on our existing rate tariffs, lower commercial and industrial demand of \$0.5 million and lower Peak View margins of \$0.3 million. These decreases were partially offset by a \$1.7 million increase in residential margins

from colder weather in the current year, higher rider revenues of \$1.6 million primarily related to transmission investment recovery and higher non-energy revenue of \$2.6 million.

Operations and maintenance increased primarily due to \$2.8 million of higher vegetation management expenses. Higher employee costs, property taxes and outage related expenses comprise the remainder of the increase compared to the same period in the prior year.

Depreciation and amortization increased primarily due to a higher asset base driven by the prior year additions of Horizon Point and the Teckla-Osage transmission line.

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

Other income (expense), net decreased due to higher prior year AFUDC associated with higher prior year capital spend.

Income tax benefit (expense): The effective tax rate decreased from the prior year due to the reduction in the federal corporate income tax rate from 35 percent to 21 percent from the TCJA, effective January 1, 2018.

Operating Statistics

| | Electric Revenue | | Quantities sold | |
|---------------------------------------|------------------|-----------|-----------------|-----------|
| | (in thousands) | | (MWh) | |
| | Three Months | | Three Months | |
| | Ended | | Ended | |
| | March 31, | March 31, | March 31, | March 31, |
| | 2018 | 2017 | 2018 | 2017 |
| Residential | \$55,741 | \$54,218 | 383,270 | 362,105 |
| Commercial | 61,984 | 63,513 | 500,136 | 504,074 |
| Industrial | 30,800 | 30,283 | 400,709 | 390,574 |
| Municipal | 4,141 | 4,300 | 36,324 | 36,972 |
| Subtotal Retail Revenue - Electric | 152,666 | 152,314 | 1,320,439 | 1,293,725 |
| Contract Wholesale | 9,050 | 7,843 | 237,704 | 186,116 |
| Off-system/Power Marketing Wholesale | 4,144 | 5,510 | 129,041 | 187,435 |
| Other | 7,695 | 10,357 | — | — |
| Total Revenue and Energy Sold | 173,555 | 176,024 | 1,687,184 | 1,667,276 |
| Other Uses, Losses or Generation, net | — | — | 90,855 | 103,335 |
| Total Revenue and Energy | 173,555 | 176,024 | 1,778,039 | 1,770,611 |
| Less cost of fuel and purchased power | 67,123 | 68,400 | | |
| Gross Margin | \$106,432 | \$107,624 | | |

| Three Months Ended March 31, | Electric Revenue | | Gross Margin | | Quantities Sold | |
|---|------------------|-----------|----------------|-----------|-----------------|-----------|
| | (in thousands) | | (in thousands) | | (MWh) | |
| | 2018 | 2017 | (a) 2018 | (a) 2017 | (b) 2018 | (b) 2017 |
| South Dakota Electric | \$73,815 | \$73,794 | \$51,376 | \$50,645 | 828,177 | 845,832 |
| Wyoming Electric | 41,387 | 42,278 | 21,695 | 22,786 | 462,862 | 439,907 |
| Colorado Electric | 58,353 | 59,952 | 33,361 | 34,193 | 487,000 | 484,872 |
| Total Electric Revenue, Gross Margin, and Quantities Sold | \$173,555 | \$176,024 | \$106,432 | \$107,624 | 1,778,039 | 1,770,611 |

(a) Non-GAAP measure

(b) Total MWh includes Other Uses, Losses or Generation, net, which is approximately 3%, 6%, and 7% for South Dakota Electric, Wyoming Electric, and Colorado Electric, respectively.

Three Months
Ended

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| Quantities Generated and Purchased (MWh) | March 31, | |
|--|-----------|-----------|
| | 2018 | 2017 |
| Coal-fired | 595,600 | 572,080 |
| Natural Gas and Oil | 41,323 | 28,529 |
| Wind | 73,981 | 70,543 |
| Total Generated | 710,904 | 671,152 |
| Purchased | 1,067,135 | 1,099,459 |
| Total Generated and Purchased | 1,778,039 | 1,770,611 |

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| | Three Months Ended March 31, | |
|--|------------------------------------|-----------|
| Quantities Generated and Purchased (MWh) | 2018 | 2017 |
| Generated: | | |
| South Dakota Electric | 412,194 | 398,335 |
| Wyoming Electric | 206,662 | 190,372 |
| Colorado Electric | 92,048 | 82,445 |
| Total Generated | 710,904 | 671,152 |
| Purchased: | | |
| South Dakota Electric | 415,983 | 447,497 |
| Wyoming Electric | 256,200 | 249,535 |
| Colorado Electric | 394,952 | 402,427 |
| Total Purchased | 1,067,135 | 1,099,459 |
| Total Generated and Purchased | 1,778,039 | 1,770,611 |

| Degree Days | Three Months Ended March 31, | | | |
|-------------------------|------------------------------|-------------------------------|--------|-------------------------------|
| | 2018 | | 2017 | |
| | Actual | Variance from 30-Year Average | Actual | Variance from 30-Year Average |
| | | Actual Variance to Prior Year | | |
| Heating Degree Days: | | | | |
| South Dakota Electric | 3,699 | 15 % | 18% | 3,130 (3)% |
| Wyoming Electric | 2,984 | (7)% | 9% | 2,730 (10)% |
| Colorado Electric | 2,406 | (9)% | 14% | 2,119 (19)% |
| Combined ^(a) | 2,964 | 1 % | 15% | 2,587 (11)% |

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

| Electric Utilities Power Plant Availability | Three Months Ended March 31, | |
|---|------------------------------------|-------|
| | 2018 | 2017 |
| Coal-fired plants | 95.0% | 91.2% |
| Natural gas-fired plants and Other plants | 96.5% | 98.4% |
| Wind | 97.1% | 91.5% |
| Total availability | 96.1% | 95.5% |
| Wind capacity factor | 50.4% | 43.6% |

Gas Utilities

| | Three Months Ended March | | |
|---|--------------------------|-----------|----------|
| | 31, 2018 | 2017 | Variance |
| | (in thousands) | | |
| Revenue: | | | |
| Natural gas — regulated | \$370,268 | \$332,696 | \$37,572 |
| Other — non-regulated services ^(a) | 27,076 | 32,214 | (5,138) |
| Total revenue | 397,344 | 364,910 | 32,434 |
| Cost of sales | | | |
| Natural gas — regulated | 205,084 | 169,702 | 35,382 |
| Other — non-regulated services ^(a) | 4,601 | 11,680 | (7,079) |
| Total cost of sales | 209,685 | 181,382 | 28,303 |
| Gross margin | 187,659 | 183,528 | 4,131 |
| Operations and maintenance | 70,906 | 70,759 | 147 |
| Depreciation and amortization | 21,310 | 20,797 | 513 |
| Total operating expenses | 92,216 | 91,556 | 660 |
| Operating income | 95,443 | 91,972 | 3,471 |
| Interest expense, net | (19,766) | (19,782) | 16 |
| Other income (expense), net | 155 | 177 | (22) |
| Income tax benefit (expense) | 31,788 | (26,250) | 58,038 |
| Net income (loss) | 107,620 | 46,117 | 61,503 |
| Net (income) loss attributable to noncontrolling interest | — | (107) | 107 |
| Net income (loss) available for common stock | \$107,620 | \$46,010 | \$61,610 |

(a) The three months ended March 31, 2018 includes certain BHES trading activities which are reported on a net basis. These trading activities are presented on a gross basis in the prior year. This change in presentation had no impact on gross margin.

Results of Operations for the Gas Utilities for the Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017: Net income from continuing operations available for common stock for the Gas Utilities was \$108 million for the three months ended March 31, 2018, compared to Net income from continuing operations available for common stock of \$46 million for the three months ended March 31, 2017, as a result of:

Gross margin increased primarily due to a \$9.1 million weather impact from colder winter temperatures as our service territories experienced colder weather in the current period compared to the same period in the prior year. Heating degree days were 2 percent higher than normal in the current year compared to 13 percent below normal for the same period in the prior year. Customer growth added \$1.8 million in additional margin over the prior year and rider revenues increased by \$1.8 million primarily from our capital integrity recovery riders. These increases over the prior year are partially offset by a \$9.1 million current year reserve to revenue to reflect the reduction of the lower federal income tax rate from the TCJA on our existing rate tariffs.

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

Depreciation and amortization increased due to a higher asset base driven by previous year capital expenditures.

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

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

Income tax benefit (expense): The 2018 tax benefit is due to legal restructuring to enable jurisdictional simplification that resulted in the recognition of a deferred tax benefit of approximately \$49 million associated with amortizable goodwill for tax purposes. The current year effective tax rate also reflects the reduction of the federal corporate income tax rate from 35 percent to 21 percent from the TCJA, effective January 1, 2018.

Operating Statistics

| | Gas Revenue (in thousands) | | Gross Margin ^(a) (in thousands) | |
|----------------------------------|----------------------------|-----------|--|-----------|
| | Three Months Ended | | Three Months Ended | |
| | March 31, | | March 31, | |
| | 2018 | 2017 | 2018 | 2017 |
| Residential | \$234,751 | \$205,352 | \$96,777 | \$91,051 |
| Commercial | 95,005 | 81,736 | 32,203 | 29,799 |
| Industrial | 5,982 | 4,946 | 1,674 | 1,482 |
| Other ^(a) | (7,531) |)2,388 | (7,531) |)2,388 |
| Total Distribution | 328,207 | 294,422 | 123,123 | 124,720 |
| Transportation and Transmission | 42,061 | 38,274 | 42,061 | 38,274 |
| Total Regulated | 370,268 | 332,696 | 165,184 | 162,994 |
| Non-regulated Services | 27,076 | 32,214 | 22,475 | 20,534 |
| Total Gas Revenue & Gross Margin | \$397,344 | \$364,910 | \$187,659 | \$183,528 |

(a) Includes current year reserve to revenue to reflect the reduction of the lower federal income tax rate from the TCJA on our existing rate tariffs.

| | Revenue (in thousands) | | Gross Margin ^(a) (in thousands) | |
|----------------------------------|------------------------|-----------|--|-----------|
| | Three Months Ended | | Three Months Ended | |
| | March 31, | | March 31, | |
| | 2018 | 2017 | 2018 | 2017 |
| Arkansas | \$70,388 | \$61,098 | \$35,917 | \$37,309 |
| Colorado | 71,398 | 67,179 | 33,145 | 34,363 |
| Nebraska | 106,761 | 98,315 | 53,860 | 49,752 |
| Iowa | 67,884 | 57,448 | 22,426 | 21,452 |
| Kansas | 42,381 | 38,949 | 17,897 | 17,463 |
| Wyoming | 38,532 | 41,921 | 24,414 | 23,189 |
| Total Gas Revenue & Gross Margin | \$397,344 | \$364,910 | \$187,659 | \$183,528 |

(a) Non-GAAP measure

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| | Three Months Ended March 31, | |
|---|---------------------------------|------------|
| Gas Utilities Quantities Sold & Transported (Dth) | 2018 | 2017 |
| Residential | 30,096,237 | 25,268,134 |
| Commercial | 13,949,121 | 11,704,314 |
| Industrial | 1,183,617 | 926,887 |
| Total Distribution Quantities Sold | 45,228,975 | 37,899,335 |
| Transportation and Transmission | 44,733,475 | 40,812,874 |
| Total Quantities Sold & Transported | 89,962,450 | 78,712,209 |
| | Three Months Ended March 31, | |
| Gas Utilities Quantities Sold & Transported (Dth) | 2018 | 2017 |
| Arkansas | 11,878,626 | 9,212,085 |
| Colorado | 11,703,351 | 10,987,644 |
| Nebraska | 27,987,224 | 24,272,789 |
| Iowa | 15,502,989 | 13,495,012 |
| Kansas | 10,297,328 | 8,509,318 |
| Wyoming | 12,592,932 | 12,235,361 |
| Total Quantities Sold & Transported | 89,962,450 | 78,712,209 |

Our Gas Utilities are highly seasonal, and sales volumes vary considerably with weather and seasonal heating and industrial loads. Approximately 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 March 31, | | | 2017 | Variance from 30-Year Average |
|-------------------------|------------------------------|-------------------------------------|-------------------------------|--------|--|
| | 2018 | Variance from 30-Year Average | Actual Variance to Prior Year | | |
| Heating Degree Days: | Actual | | Actual | Actual | |
| Arkansas ^(a) | 2,048 | (3)% | 31% | 1,569 | (25)% |
| Colorado | 2,704 | (8)% | 10% | 2,465 | (16)% |
| Nebraska | 3,207 | 6% | 21% | 2,647 | (13)% |
| Iowa | 3,531 | 5% | 20% | 2,932 | (13)% |
| Kansas ^(a) | 2,470 | —% | 18% | 2,102 | (15)% |
| Wyoming | 3,244 | 1% | 9% | 2,984 | (7)% |
| Combined ^(b) | 3,159 | 2% | 16% | 2,718 | (13)% |

(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 residential and business 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.

The combined heating degree days are calculated based on a weighted average of total customers by state (b)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.

Regulatory Matters

For more information on recent regulatory activity and enacted regulatory provisions with respect to the states in which our Utilities operate, see Note 5 of the Notes to Condensed Consolidated Financial Statements of this Quarterly Report on Form 10-Q and Part I, Items 1 and 2 and Part II, Item 8 of our 2017 Annual Report on Form 10-K filed with the SEC.

Power Generation

| | Three Months Ended March 31, | | |
|--|------------------------------|----------|-----------|
| | 2018 | 2017 | Variance |
| | (in thousands) | | |
| Revenue ^(a) | \$23,103 | \$23,567 | \$ (464) |
| Operations and maintenance | 8,127 | 8,054 | 73 |
| Depreciation and amortization ^(a) | 1,602 | 1,207 | 395 |
| Total operating expense | 9,729 | 9,261 | 468 |
| Operating income | 13,374 | 14,306 | (932) |
| Interest expense, net | (1,173) | (587) | (586) |
| Other (expense) income, net | 6 | (18) | 24 |
| Income tax (expense) benefit | (2,721) | (3,655) | 934 |
| Net income | 9,486 | 10,046 | (560) |
| Net income attributable to noncontrolling interest | (3,630) | (3,516) | (114) |
| Net income available for common stock | \$5,856 | \$6,530 | \$ (674) |

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 ^(a) of the facility is recorded at Colorado Electric and is being depreciated by Colorado Electric for segment reporting purposes.

In 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Colorado IPP. 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 Colorado Electric. Net income available for common stock for the three months ended March 31, 2018 and March 31, 2017 was reduced by \$3.6 million and \$3.5 million, respectively, attributable to this noncontrolling interest.

Results of Operations for Power Generation for the Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017: Net income from continuing operations available for common stock for the Power Generation segment was \$5.9 million for the three months ended March 31, 2018, compared to Net income from continuing operations available for common stock of \$6.5 million for the same period in 2017. Revenue decreased in the current year as a result of lower Wygen I MWh sold. Operating expenses increased from higher depreciation in the current year. The variance in tax expense reflects the reduction in the federal tax rate from 35 percent to 21 percent from the TCJA, effective January 1, 2018, partially offset by \$0.7 million of additional tax expense recorded on a valuation allowance due to changes in estimated future taxable income subsequent to the TCJA.

The following table summarizes MWh for our Power Generation segment:

| | Three Months Ended March 31, 2018 2017 | |
|--|---|---------|
| Quantities Sold, Generated and Purchased (MWh) ^(a) | | |
| Sold | | |
| Black Hills Colorado IPP ^(b) | 232,375 | 254,965 |
| Black Hills Wyoming ^(c) | 165,601 | 170,376 |
| Total Sold | 397,976 | 425,341 |
| Generated | | |
| Black Hills Colorado IPP ^(b) | 232,375 | 254,965 |
| Black Hills Wyoming ^(c) | 134,029 | 140,240 |
| Total Generated | 366,404 | 395,205 |
| Purchased | | |
| Black Hills Colorado IPP | — | — |
| Black Hills Wyoming ^(c) | 31,917 | 21,255 |
| Total Purchased | 31,917 | 21,255 |

(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 impact of Colorado Electric's wind generation replacing natural-gas generation.

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 March 31, 2018 2017 | |
|--|---|---------|
| Contracted power plant fleet availability: | | |
| Coal-fired plant | 94.7 % | 100.0 % |
| Natural gas-fired plants | 99.5 % | 99.1 % |
| Total availability | 98.3 % | 99.3 % |

Mining

| | Three Months Ended March 31, | | |
|--|---------------------------------|----------|----------|
| | 2018 | 2017 | Variance |
| | (in thousands) | | |
| Revenue | \$17,128 | \$16,546 | \$ 582 |
| Operations and maintenance | 10,922 | 11,094 | (172) |
| Depreciation, depletion and amortization | 1,935 | 2,165 | (230) |
| Total operating expenses | 12,857 | 13,259 | (402) |
| Operating income | 4,271 | 3,287 | 984 |
| Interest (expense) income, net | (100) | (25) | (75) |
| Other income, net | (26) | 541 | (567) |
| Income tax benefit (expense) | (1,161) | (913) | (248) |
| Net income | \$2,984 | \$2,890 | \$ 94 |

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

| | Three Months Ended March 31, | |
|---------------------------------|------------------------------------|---------|
| | 2018 | 2017 |
| Tons of coal sold | 1,078 | 1,049 |
| Cubic yards of overburden moved | 2,022 | 2,104 |
| Revenue per ton | \$15.89 | \$15.78 |

Results of Operations for Mining for the Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017: Net income from continuing operations available for common stock for the Mining segment was \$3.0 million for the three months ended March 31, 2018, compared to Net income from continuing operations available for common stock of \$2.9 million for the same period in 2017 as a result of:

Revenue increased due to a 3 percent increase in tons sold, with comparable pricing to the same period last year. Current year revenue is also reflective of lease and rental revenue, previously reported in Other income (expense), net. During the current period, approximately 48 percent of the mine's production was sold under contracts that include price adjustments based on actual mining costs, including income taxes.

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

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

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

Other income, net decreased from the prior year due to the presentation change of lease and rental revenue to Revenue in the current year, previously reported in Other income (expense), net.

Income tax benefit (expense): The variance in tax expense to the prior year reflects the reduction in the federal corporate income tax rate from 35 percent to 21 percent from the TCJA, effective January 1, 2018, partially offset by \$0.5 million of additional tax expense related to previous years' other comprehensive items pursuant to the TCJA.

Corporate and Other

| | Three Months Ended | | |
|---|--------------------|-----------|-----------|
| | March 31, | | |
| | 2018 | 2017 | Variance |
| | (in thousands) | | |
| Operating (loss) ^(a) | \$(1,640) | \$(3,359) | \$1,719 |
| Other income (expense): | | | |
| Interest (expense) income, net ^(a) | (665) | (650) | (15) |
| Other income (expense), net | (58) | (667) | 609 |
| Income tax benefit (expense) | 1,405 | 5,108 | (3,703) |
| Net income (loss) | \$(958) | \$432 | \$(1,390) |

^(a) Includes certain general and administrative expenses and interest expenses that are not reported as discontinued operations.

Results of Operations for Corporate and Other for the Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017: Net loss from continuing operations available for common stock for Corporate and Other was \$(1.0) million for the three months ended March 31, 2018, compared to Net income from continuing operations available for common stock of \$0.4 million for the three months ended March 31, 2017. The variance to the prior year was driven by transition and acquisition expenses which occurred in the prior year. Income tax benefit (expense) decreased due to a higher prior year tax benefit of \$1.4 million comprised primarily of benefits from a carryback claim for specified liability losses involving prior tax years, and approximately \$0.6 million of current year tax expense recorded pursuant to the TCJA.

Discontinued Operations

| | Three Months Ended | | |
|--|--------------------|-----------|-----------|
| | March 31, | | |
| | 2018 | 2017 | Variance |
| | (in thousands) | | |
| Revenue | \$3,915 | \$6,475 | \$(2,560) |
| Operations and maintenance | 5,901 | 7,205 | (1,304) |
| Depreciation, depletion and amortization | 1,300 | 1,945 | (645) |
| Total operating expenses | 7,201 | 9,150 | (1,949) |
| Operating (loss) | (3,286) | (2,675) | (611) |
| Other income (expense), net | 29 | 73 | (44) |
| Income tax benefit (expense) | 914 | 1,033 | (119) |
| (Loss) from discontinued operations available for common stock | \$(2,343) | \$(1,569) | \$(774) |

Results of Discontinued Operations for the Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017: Net loss from discontinued operations was \$(2.3) million for the three months ended March 31, 2018, compared to Net loss from discontinued operations of \$(1.6) million for the same period in 2017. The variance to the prior year is driven by lower revenues due to current year and prior year property sales, partially offset

by lower oil and gas operating expenses and lower employee costs. Current year depreciation expense is representative of the write-down of the remaining book value of accounting software. Depreciation expense in the prior year is reflective of full cost accounting on full cost pool assets as full cost accounting continued through November 1, 2017.

Critical Accounting Estimates

There have been no material changes in our critical accounting estimates from those reported in our 2017 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 2017 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. As discussed in more detail below under income taxes, we expect an increase in working capital requirements as a result of complying with the TCJA and the impact of providing TCJA benefits to customers.

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 March 31, 2018, we had sufficient liquidity to cover collateral that could be required to be posted under these contracts.

Income Tax

The TCJA legislation was signed into law on December 22, 2017. The new tax law required revaluation at December 31, 2017 of federal deferred tax assets and liabilities using the new lower corporate tax rate of 21%. As a result of the revaluation, deferred tax assets and liabilities were reduced by approximately \$309 million. Of the \$309 million,

approximately \$301 million is related to our regulated utilities and is reclassified to a regulatory liability. This regulatory liability will generally be amortized over the remaining life of the related assets as specifically prescribed in the TCJA.

We expect an increase in working capital requirements as a result of complying with the TCJA and the impact of providing TCJA benefits to customers. We estimate the lower tax rate will negatively impact the Company's cash flows by approximately \$35 million to \$45 million annually for the next several years. Each of our utilities is working with their respective regulators to address the impact of tax reform and the appropriate benefit to customers.

Cash Flow Activities

The following table summarizes our cash flows for the three months ended March 31 (in thousands):

| Cash provided by (used in): | 2018 | 2017 | Increase (Decrease) |
|-----------------------------|------------|------------|------------------------|
| Operating activities | \$169,875 | \$146,840 | \$23,035 |
| Investing activities | \$(73,554) | \$(69,359) | \$(4,195) |
| Financing activities | \$(80,656) | \$(79,573) | \$(1,083) |

Year-to-Date 2018 Compared to Year-to-Date 2017

Operating Activities

Net cash provided by operating activities was \$170 million for the three months ended March 31, 2018, compared to net cash provided by operating activities of \$147 million for the same period in 2017 for a variance of \$23 million.

The variance was primarily attributable to:

Cash earnings (net income plus non-cash adjustments) were \$2.7 million lower for the three months ended March 31, 2018 compared to the same period in the prior year;

Net cash outflows from changes in operating assets and liabilities were \$1.3 million for the three months ended March 31, 2018, compared to net cash outflows of \$30 million in the same period in the prior year. This \$28 million variance was primarily due to:

Cash inflows decreased by approximately \$55 million primarily as a result of changes in our accounts receivable, unbilled revenues and other operating assets, partially offset by lower natural gas in storage for the three months ended March 31, 2018 compared to the same period in the prior year;

Cash outflows decreased by approximately \$27 million as a result of changes in accounts payable and accrued liabilities driven by changes in working capital requirements;

Cash inflows increased by approximately \$55 million as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and cash collected from customers on billings that do not reflect benefits of the TCJA compared to the same period in the prior year;

Investing Activities

Net cash used in investing activities was \$74 million for the three months ended March 31, 2018, compared to net cash used in investing activities of \$69 million for the same period in 2017 for a variance of \$4.2 million. This variance was primarily due to:

Capital expenditures of approximately \$70 million for the three months ended March 31, 2018 compared to \$66 million for the three months ended March 31, 2017.

A \$24 million investment partially offset by \$23 million primarily due to net proceeds from the sale of assets held for sale.

Financing Activities

Net cash used in financing activities for the three months ended March 31, 2018 was \$81 million, compared to \$80 million of net cash used in financing activities for the same period in 2017 for a variance of \$1.1 million. This variance is primarily due to higher current year dividend payments.

Dividends

Dividends paid on our common stock totaled \$25 million for the three months ended March 31, 2018, or \$0.475 per share per quarter. On April 23, 2018, our board of directors declared a quarterly dividend of \$0.475 per share payable June 1, 2018, equivalent to an annual dividend of \$1.90 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

Our \$750 million corporate Revolving Credit Facility extends through August 9, 2021 with two one-year extension options. The Facility 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