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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2019

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission File Number 001-31303

Black Hills Corporation

Incorporated in South Dakota IRS Identification Number 46-0458824

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 x No o

Indicate by check mark whether the Registrant has submitted electronically every Interactive Data File required to be submitted 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 such files).

Yes x No o

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

Large accelerated filer x Accelerated filer o

Non-accelerated filer o Smaller reporting company o

Emerging growth company o

If an emerging growth company, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

Yes o No x

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock of $1.00 par value	BKH	New York Stock Exchange

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, 2019
Common stock, $1.00 par value	60,367,972 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.
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
Busch Ranch I	Busch Ranch Wind Farm is a 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and Black Hills Electric Generation. Colorado Electric and Black Hills Electric Generation each have a 50% ownership interest in the wind farm.
Busch Ranch II	Busch Ranch II wind project will be a 60 MW wind farm near Pueblo, Colorado, built by Black Hills Electric Generation to provide wind energy to Colorado Electric through a 25-year power purchase agreement.
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)
Choice Gas Program	The unbundling of the natural gas service from the distribution component, which opens up the gas supply for competition allowing customers to choose from different natural gas suppliers. Black Hills Gas Distribution distributes the gas and Black Hills Energy Services is one of the Choice Gas suppliers.
CIAC	Contribution In Aid of Construction
City of Gillette	Gillette, Wyoming
Colorado Electric	Black Hills Colorado Electric, LLC, 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) plus Consolidated Indebtedness (including letters of credit and certain guarantees issued) as defined within the current Credit Agreement.
Cooling Degree Day (CDD)	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.
CPCN	Certificate of Public Convenience and Necessity
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 had 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 that were formerly due 2028. On November 1, 2018, we completed settlement of the stock purchase contracts that are components of the Equity Units issued in November 2015.
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
Heating Degree Day (HDD)	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.
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)
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)
NPSC	Nebraska Public Service Commission
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 was amended and restated on July 30, 2018 and now terminates on July 30, 2023.
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
Tech Services	Non-regulated product lines within Black Hills Corporation that 1) provide electrical system construction services to large industrial customers of our electric utilities, and 2) serve gas transportation customers throughout its service territory by constructing and maintaining customer-owner gas infrastructure facilities, typically through one-time contracts.
WPSC	Wyoming Public Service Commission
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, 2019	2018
	(in thousands, except per share amounts)	
Revenue	$ 597,810	$ 575,389
Operating expenses:		
Fuel, purchased power and cost of natural gas sold	248,779	247,639
Operations and maintenance	123,913	116,096
Depreciation, depletion and amortization	51,028	48,590
Taxes - property and production	13,519	13,300
Other operating expenses	440	1,490
Total operating expenses	437,679	427,115
Operating income	160,131	148,274
Other income (expense):		
Interest charges -		
Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	(35,974)	(35,438)
Allowance for funds used during construction - borrowed	958	133
Interest income	299	310
Allowance for funds used during construction - equity	48	68
Other income (expense), net	(837)	(172)
Total other income (expense)	(35,506)	(35,099)
Income before income taxes	124,625	113,175
Income tax benefit (expense)	(17,263)	25,802
Income from continuing operations	107,362	138,977
Net (loss) from discontinued operations	—	(2,343)
Net income	107,362	136,634
Net income attributable to noncontrolling interest	(3,554)	(3,630)
Net income available for common stock	$ 103,808	$ 133,004
Amounts attributable to common shareholders:		
Net income from continuing operations	$ 103,808	$ 135,347
Net (loss) from discontinued operations	—	(2,343)
Net income available for common stock	$ 103,808	$ 133,004
Earnings (loss) per share of common stock, Basic -		
Earnings from continuing operations	$ 1.73	$ 2.54
(Loss) from discontinued operations	—	(0.05)
Total earnings per share of common stock, Basic	$ 1.73	$ 2.49
Earnings (loss) per share of common stock, Diluted -		
Earnings from continuing operations	$ 1.73	$ 2.50
(Loss) from discontinued operations	—	(0.04)
Total earnings per share of common stock, Diluted	$ 1.73	$ 2.46
Weighted average common shares outstanding:		
Basic	59,920	53,319
Diluted	60,060	54,122

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

(unaudited)	Three Months Ended March 31,	
	2019	2018
	(in thousands)	
Net income	$ 107,362	$ 136,634
Other comprehensive income (loss), net of tax:		
Reclassification adjustments of benefit plan liability - prior service cost (net of tax of $5 and $10, respectively)	(14)	(35)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax of $(53) and $(136), respectively)	167	486
Derivative instruments designated as cash flow hedges:		
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(163) and $(152), respectively)	550	561
Net unrealized gains (losses) on commodity derivatives (net of tax of $(54) and $69, respectively)	180	(228)
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $128 and $(145), respectively)	(426)	476
Other comprehensive income, net of tax	457	1,260
Comprehensive income	107,819	137,894
Less: comprehensive income attributable to noncontrolling interest	(3,554)	(3,630)
Comprehensive income available for common stock	$ 104,265	$ 134,264

See Note 13 for additional disclosures.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of		
	March 31, 2019	December 31, 2018	March 31, 2018
		(in thousands)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 12,225	$ 20,776	$ 30,947
Restricted cash	3,494	3,369	2,958
Accounts receivable, net	282,602	269,153	257,772
Materials, supplies and fuel	87,676	117,299	82,045
Derivative assets, current	932	1,500	295
Income tax receivable, net	15,309	12,978	13,900
Regulatory assets, current	54,303	48,776	54,492
Other current assets	28,029	29,982	24,972
Current assets held for sale	—	—	24,724
Total current assets	484,570	503,833	492,105
Investments	41,247	41,013	40,927
Property, plant and equipment	6,127,050	6,000,015	5,608,539
Less: accumulated depreciation and depletion	(1,187,112)	(1,145,136)	(1,048,933)
Total property, plant and equipment, net	4,939,938	4,854,879	4,559,606
Other assets:			
Goodwill	1,299,454	1,299,454	1,299,454
Intangible assets, net	14,136	14,337	7,357
Regulatory assets, non-current	232,404	235,459	212,740
Other assets, non-current	25,823	14,352	14,800
Total other assets, non-current	1,571,817	1,563,602	1,534,351
TOTAL ASSETS	$ 7,037,572	$ 6,963,327	$ 6,626,989

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, 2019	December 31, 2018	March 31, 2018
	(in thousands, except share amounts)		
LIABILITIES AND TOTAL EQUITY			
Current liabilities:			
Accounts payable	$ 178,678	$ 210,609	$ 106,281
Accrued liabilities	196,072	215,501	194,040
Derivative liabilities, current	95	947	891
Regulatory liabilities, current	45,777	29,810	42,499
Notes payable	164,650	185,620	164,200
Current maturities of long-term debt	5,743	5,743	255,743
Current liabilities held for sale	—	—	24,910
Total current liabilities	591,015	648,230	788,564
Long-term debt	2,950,299	2,950,835	2,858,787
Deferred credits and other liabilities:			
Deferred income tax liabilities, net	337,184	311,331	290,491
Regulatory liabilities, non-current	511,482	510,984	495,362
Benefit plan liabilities	145,883	145,147	160,580
Other deferred credits and other liabilities	118,007	109,377	105,221
Total deferred credits and other liabilities	1,112,556	1,076,839	1,051,654
Commitments and contingencies (See Notes 8, 10, 15, 16)			
Equity:			
Stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 60,378,020; 60,048,567; and 53,648,817 shares, respectively	60,378	60,049	53,649
Additional paid-in capital	1,469,410	1,450,569	1,151,933
Retained earnings	777,262	700,396	656,161
Treasury stock, at cost – 23,756; 44,253; and 53,959 shares, respectively	(1,432)	(2,510)	(3,049)
Accumulated other comprehensive income (loss)	(26,459)	(26,916)	(39,924)
Total stockholders' equity	2,279,159	2,181,588	1,818,770
Noncontrolling interest	104,543	105,835	109,214
Total equity	2,383,702	2,287,423	1,927,984
TOTAL LIABILITIES AND TOTAL EQUITY	$ 7,037,572	$ 6,963,327	$ 6,626,989

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,	
	2019	2018
Operating activities:	(in thousands)	
Net income	$ 107,362	$ 136,634
Loss from discontinued operations, net of tax	—	2,343
Income from continuing operations	107,362	138,977
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	51,028	48,590
Deferred financing cost amortization	2,007	1,900
Stock compensation	3,296	2,209
Deferred income taxes	19,602	(25,430)
Employee benefit plans	3,137	3,378
Other adjustments, net	4,428	3,053
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	29,387	31,196
Accounts receivable, unbilled revenues and other operating assets	(15,857)	(25,113)
Accounts payable and other operating liabilities	(41,689)	(71,149)
Regulatory assets - current	13,031	47,903
Regulatory liabilities - current	(1,635)	16,098
Other operating activities, net	1,796	(278)
Net cash provided by operating activities of continuing operations	175,893	171,334
Net cash provided by (used in) operating activities of discontinued operations	—	(1,459)
Net cash provided by operating activities	175,893	169,875
Investing activities:		
Property, plant and equipment additions	(144,126)	(69,972)
Purchase of investment	—	(23,500)
Other investing activities	(901)	(261)
Net cash provided by (used in) investing activities of continuing operations	(145,027)	(93,733)
Net cash provided by (used in) investing activities of discontinued operations	—	20,179
Net cash provided by (used in) investing activities	(145,027)	(73,554)
Financing activities:		
Dividends paid on common stock	(30,332)	(25,444)
Common stock issued	19,949	372
Net (payments) borrowings of short-term debt	(20,970)	(47,100)
Long-term debt - repayments	(1,436)	(1,436)
Distributions to noncontrolling interest	(4,846)	(5,648)
Other financing activities	(1,657)	(1,400)
Net cash provided by (used in) financing activities	(39,292)	(80,656)
Net change in cash, cash equivalents and restricted cash	(8,426)	15,665
Cash, cash equivalents and restricted cash at beginning of period	24,145	18,240
Cash, cash equivalents and restricted cash at end of period	$ 15,719	$ 33,905

See Note 14 for supplemental disclosure of cash flow information.

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

(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 2018 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.

Accounting standards for presentation of segments requires an approach based on the way we organize the segments for making operating decisions and how the chief operating decision maker (CODM) assesses performance. We have changed our segment performance metrics and concluded that adjusted operating income, instead of net income available for common stock which was used previously, is the most relevant metric for measuring segment performance.

The CODM assesses the performance of our segments by using adjusted operating income, which considers the power sales arrangement between Colorado IPP and Colorado Electric be treated as an executory contract. Adjusted operating income adjusts this power sales arrangement from being accounted for as a capital lease to being accounted for as an executory contract on an accrual basis. This adjustment impacts Electric Utilities and Power Generation segments and Corporate and Other. There were no adjustments to Gas Utilities and Mining segments and this adjustment had no effect on our consolidated operating income.

The change to our segment performance measure resulted in a revision of the Company's segment disclosures for all periods to report adjusted operating income as the measure of segment profit and adjust revenues, operating income, and total assets for the power sales agreement to an executory contract and not a capital lease. See Notes 2 and 3 for more information.

On November 1, 2017, the BHC board of directors approved a complete divestiture of our Oil and Gas segment. We completed the divestiture of our Oil and Gas segment in 2018. The Oil and Gas segment assets and liabilities have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, except for certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. At the time the assets were classified as held for sale, depreciation, depletion and amortization expenses were no longer recorded. Unless otherwise noted, the amounts presented in the accompanying notes to the Condensed Consolidated Financial Statements relate to the Company's continuing operations. See Note 17 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, 2019, December 31, 2018, and March 31, 2018 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. 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, 2019 and March 31, 2018, and our financial condition as of March 31, 2019, December 31, 2018, and March 31, 2018, are not necessarily indicative of the results of operations and financial condition to be expected for any other period. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

Recently Issued Accounting Standards

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 1, 2019, applied on a prospective basis with early adoption permitted. We do not anticipate the adoption of this guidance to have any impact on our financial position, results of operations or cash flows.

Recently Adopted Accounting Standards

Leases, ASU 2016-02

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* to increase transparency and comparability among organizations by requiring the recognition of right-of-use assets and lease liabilities on the balance sheet for most leases, whereas previously only financing-type lease liabilities (capital leases) were recognized on the balance sheet. Under the new standard, disclosures are required to meet the objective of enabling users of financial statements to assess the amount, timing and uncertainty of cash flows arising from leases.

We adopted the standard effective January 1, 2019. We elected not to recast comparative periods coinciding with the new lease standard transition and will report these comparative periods as presented under previous lease guidance. In addition, we elected the package of practical expedients permitted under the transition guidance with the new standard, which among other things, allowed us to carry forward the historical lease classification. We also elected the practical expedient related to land easements, allowing us to carry forward our accounting treatment for existing land easement agreements.

Adoption of the new standard resulted in the recording of an operating lease right-of-use asset of $3.1 million, an operating lease obligation liability of $3.2 million, and an accrued rent receivable of $4.5 million, as of January 1, 2019. The cumulative effect of the adoption, net of tax impact, was $3.4 million, which was recorded as an adjustment to retained earnings.

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

Effective January 1, 2019, we adopted 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. The adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

(2) REVENUE

Revenue Recognition

As of January 1, 2018, we adopted ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, and its related amendments (collectively known as ASC 606). Revenue is 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. The following tables depict 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, for the three months ended March 31, 2019 and 2018. Sales tax and other similar taxes are excluded from revenues.

Three Months Ended March 31, 2019	Electric Utilities	Gas Utilities	Power Generation [a]	Mining	Inter-company Revenues [a]	Total
Customer types:			(in thousands)			
Retail	$ 153,463	$ 354,275	$ —	$ 15,829	$ (8,128)	$ 515,439
Transportation	—	44,517	—	—	(432)	44,085
Wholesale	8,343	—	15,469	—	(13,213)	10,599
Market - off-system sales	6,692	217	—	—	(2,224)	4,685
Transmission/Other	14,175	13,190	—	—	(4,203)	23,162
Revenue from contracts with customers	182,673	412,199	15,469	15,829	(28,200)	597,970
Other revenues	254	(1,119) [b]	9,776	600	(9,671)	(160)
Total revenues	$ 182,927	$ 411,080	$ 25,245	$ 16,429	$ (37,871)	$ 597,810
Timing of revenue recognition:						
Services transferred at a point in time	$ —	$ —	$ —	$ 15,829	$ (8,128)	$ 7,701
Services transferred over time	182,673	412,199	15,469	—	(20,072)	590,269
Revenue from contracts with customers	$ 182,673	$ 412,199	$ 15,469	$ 15,829	$ (28,200)	$ 597,970

Three Months Ended March 31, 2018	Electric Utilities	Gas Utilities	Power Generation [a]	Mining	Inter-company Revenues [a]	Total
Customer Types:						
Retail	$ 147,057	$ 341,394	$ —	$ 16,557	$ (7,842)	$ 497,166
Transportation	—	41,669	—	—	(409)	41,260
Wholesale	9,050	—	14,769	—	(13,049)	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	$ 14,769	$ 16,557	$ (27,453)	$ 573,355
Other Revenues	233	1,184 [b]	9,170	571	(9,124)	2,034
Total Revenues	$ 173,555	$ 397,344	$ 23,939	$ 17,128	$ (36,577)	$ 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	14,769	—	(19,611)	564,640
Revenue from contracts with customers	$ 173,322	$ 396,160	$ 14,769	$ 16,557	$ (27,453)	$ 573,355

(a) Due to changes to our segment performance measure as disclosed in Note 1, Power Generation Wholesale revenue was recast for the three months ended March 31, 2018 which resulted in a change of $0.8 million. For the three months ended March 31, 2019, the impact to Power Generation Wholesale revenue was $3.4 million. The changes to Power Generation were offset by changes to eliminations in Inter-company Revenues and there was no impact to our consolidated Total Revenues.

(b) Other revenues in the Gas Utilities segment include alternative revenue programs related to weather normalization mechanisms for Arkansas Gas and Kansas Gas that are considered out of scope for ASC 606.

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 exists. 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 revenue contract.

(3) BUSINESS SEGMENT INFORMATION

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation.

As disclosed in Note 1, changes to our segment performance measure resulted in a revision of the Company's segment disclosures for all periods to adjust revenues, operating income, and assets related to the power sales arrangement between Colorado IPP and Colorado Electric from being accounted for as a capital lease to being accounted for as an executory contract on an accrual basis. This change had no effect on our consolidated revenues, operating income, or total assets. See below for more information.

Segment information and Corporate and Other is as follows (in thousands):

	External Operating Revenue		Inter-company Operating Revenue		
Three Months Ended March 31, 2019	Contract Customers	Other Revenues	Contract Customers	Other Revenues	Total Revenues
Segment:					
Electric Utilities	$ 176,663	$ 254	$ 6,010	$ —	$ 182,927
Gas Utilities [(a)]	411,500	(1,119)	699	—	411,080
Power Generation [(b)]	2,257	436	13,212	9,340	25,245
Mining	7,550	269	8,279	331	16,429
Corporate and Other	—	—	—	—	—
Inter-company eliminations [(b)]	—	—	(28,200)	(9,671)	(37,871)
Total	$ 597,970	$ (160)	$ —	$ —	$ 597,810

	External Operating Revenue		Inter-company Operating Revenue		
Three Months Ended March 31, 2018	Contract Customers	Other Revenues	Contract Customers	Other Revenues	Total Revenues
Segment:					
Electric Utilities	$ 167,178	$ 233	$ 6,144	$ —	$ 173,555
Gas Utilities [(a)]	395,742	1,184	418	—	397,344
Power Generation [(b)]	1,720	371	13,049	8,799	23,939
Mining	8,715	246	7,842	325	17,128
Corporate and Other	—	—	—	—	—
Inter-company eliminations [(b)]	—	—	(27,453)	(9,124)	(36,577)
Total	$ 573,355	$ 2,034	$ —	$ —	$ 575,389

(a) Other revenues in the Gas Utilities segment include alternative revenue programs related to weather normalization mechanisms for Arkansas Gas and Kansas Gas that are considered out of scope for ASC 606.

(b) Due to changes to our segment performance measure, Power Generation Inter-company Operating Revenue for Contract Customers was recast for the three months ended March 31, 2018 which resulted in a change of $0.8 million. For the three months ended March 31, 2019, the impact to Power Generation Inter-company Operating Revenue for Contract Customers was $3.4 million. The changes to Power Generation were offset by changes to Inter-company eliminations and there was no impact on our consolidated Total revenues.

	Three Months Ended March 31,	
	2019	2018
Adjusted operating income:		
Electric Utilities [(a)]	$ 41,020	$ 38,480
Gas Utilities	103,314	95,443
Power Generation [(a)]	11,967	11,776
Mining	4,337	4,271
Corporate and Other [(a)]	(507)	(1,696)
Operating income	160,131	148,274
Interest expense, net	(34,717)	(34,995)
Other income (expense), net	(789)	(104)
Income tax benefit (expense) [(b)]	(17,263)	25,802
Income from continuing operations	107,362	138,977
Net (loss) from discontinued operations	—	(2,343)
Net income	107,362	136,634
Net income attributable to noncontrolling interest	(3,554)	(3,630)
Net income available for common stock	$ 103,808	$ 133,004

(a) Due to changes to our segment performance measure, Adjusted operating income was recast for the three months ended March 31, 2018, for Electric Utilities, Power Generation, and Corporate and Other which resulted in changes of $1.7 million, ($1.6) million, and ($0.1) million, respectively. The impact to Adjusted operating income for the three months ended March 31, 2019, for Electric Utilities, Power Generation, and Corporate and Other was ($5.4) million, $0.7 million, and $4.7 million, respectively. There was no impact on our consolidated Operating income.

(b) Income tax benefit (expense) for the three months ended March 31, 2018 included a $49 million tax benefit resulting from legal entity restructuring. See Note 18 for more information.

Segment information and Corporate and Other 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, 2019	December 31, 2018	March 31, 2018
Segment:			
Electric Utilities [(a)]	$ 2,755,056	$ 2,707,695	$ 2,629,267
Gas Utilities	3,639,430	3,623,475	3,398,473
Power Generation [(a)]	372,503	342,085	314,764
Mining	63,088	80,594	65,568
Corporate and Other	207,495	209,478	194,193
Discontinued operations	—	—	24,724
Total assets	$ 7,037,572	$ 6,963,327	$ 6,626,989

(a) Due to changes to our segment performance measure, Electric Utilities Total assets were recast as of December 31, 2018 and March 31, 2018 which resulted in changes of ($188) million and ($261) million, respectively. Power Generation Total Assets were recast as of December 31, 2018, and March 31, 2018 which resulted in changes of $188 million and $261 million, respectively. The impact to Electric Utilities and Power Generation Total Assets as of March 31, 2019, was ($186) million and $186 million, respectively. There was no impact on our consolidated Total assets.

(4) ACCOUNTS RECEIVABLE

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

March 31, 2019	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 45,764	$ 31,075	$ (535)	$ 76,304
Gas Utilities	138,005	62,566	(4,008)	196,563
Power Generation	3,167	—	—	3,167
Mining	2,791	—	—	2,791
Corporate	3,946	—	(169)	3,777
Total	$ 193,673	$ 93,641	$ (4,712)	$ 282,602

December 31, 2018	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 39,721	$ 35,125	$ (448)	$ 74,398
Gas Utilities	96,123	90,521	(2,592)	184,052
Power Generation	1,876	—	—	1,876
Mining	3,988	—	—	3,988
Corporate	5,008	—	(169)	4,839
Total	$ 146,716	$ 125,646	$ (3,209)	$ 269,153

March 31, 2018	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
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

(5) REGULATORY ACCOUNTING

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

	March 31, 2019	December 31, 2018	March 31, 2018
Regulatory assets			
Deferred energy and fuel cost adjustments [a]	$ 35,512	$ 29,661	$ 25,056
Deferred gas cost adjustments [a]	5,124	3,362	2,118
Gas price derivatives [a]	3,939	6,201	11,045
Deferred taxes on AFUDC [b]	7,771	7,841	7,808
Employee benefit plans [c]	111,724	110,524	109,999
Environmental [a]	945	959	1,012
Loss on reacquired debt [a]	20,570	21,001	20,267
Renewable energy standard adjustment [a]	1,533	1,722	1,600
Deferred taxes on flow through accounting [c]	33,226	31,044	28,014
Decommissioning costs [b]	11,694	11,700	12,552
Gas supply contract termination [a]	12,866	14,310	18,590
Other regulatory assets [a]	41,803	45,910	29,171
Total regulatory assets	286,707	284,235	267,232
Less current regulatory assets	(54,303)	(48,776)	(54,492)
Regulatory assets, non-current	$ 232,404	$ 235,459	$ 212,740
Regulatory liabilities			
Deferred energy and gas costs [a]	$ 19,018	$ 6,991	$ 20,194
Employee benefit plan costs and related deferred taxes [c]	42,207	42,533	40,332
Cost of removal [a]	154,170	150,123	139,002
Excess deferred income taxes [c]	307,894	310,562	310,622
TCJA revenue reserve	16,549	18,032	15,239
Other regulatory liabilities [c]	17,421	12,553	12,472
Total regulatory liabilities	557,259	540,794	537,861
Less current regulatory liabilities	(45,777)	(29,810)	(42,499)
Regulatory liabilities, non-current	$ 511,482	$ 510,984	$ 495,362

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(a) We are allowed recovery of costs, but we are not allowed a rate of return.
(b) In addition to recovery of costs, we are allowed a rate of return.
(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.

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 2018 Annual Report on Form 10-K.

Regulatory Activity

Nebraska

On March 29, 2019, Nebraska Gas filed an application with the NPSC requesting to merge its two gas distribution utilities into a new public utility entity. The filing also requests to merge the terms and conditions of the existing tariffs of the two utilities into a single tariff.

Wyoming

On March 6, 2019, Wyoming Gas filed an application with the WPSC requesting to merge its four gas distribution utilities into a new public utility entity. The filing also requests the new entity adopt the terms and conditions of the existing tariffs.

Colorado

On February 1, 2019, Colorado Gas filed a rate review with the CPUC requesting approval to consolidate the base rate areas, tariffs, terms and conditions and adjustment clauses of its two legacy utilities. The rate review also requests $2.5 million in new revenue to recover costs and investments in safety, reliability and system integrity.

(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, 2019	December 31, 2018	March 31, 2018
Materials and supplies	$ 76,728	$ 75,081	$ 72,045
Fuel - Electric Utilities	2,485	2,850	2,903
Natural gas in storage held for distribution	8,463	39,368	7,097
Total materials, supplies and fuel	$ 87,676	$ 117,299	$ 82,045

(7) EARNINGS PER SHARE

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

	Three Months Ended March 31,	
	2019	2018
Net income available for common stock	$ 103,808	$ 133,004
Weighted average shares - basic	59,920	53,319
Dilutive effect of:		
Equity Units [(a)]	—	733
Equity compensation	140	70
Weighted average shares - diluted	60,060	54,122

(a) Calculated using the treasury stock method. On November 1, 2018, we completed settlement of the stock purchase contracts that are components of the Equity Units issued in November 2015.

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,	
	2019	2018
Equity compensation	6	71
Anti-dilutive shares	6	71

(8) NOTES PAYABLE, CURRENT MATURITIES AND DEBT

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

	March 31, 2019		December 31, 2018		March 31, 2018	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$ —	$ 14,006	$ —	$ 22,310	$ —	$ 15,830
CP Program	164,650	—	185,620	—	164,200	—
Total	$ 164,650	$ 14,006	$ 185,620	$ 22,310	$ 164,200	$ 15,830

Revolving Credit Facility and CP Program

On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one year extension options (subject to consent from lenders). This facility is similar to the former revolving credit facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our Corporate credit rating from S&P, Fitch, and Moody's for our senior unsecured long-term debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.125%, 1.125%, and 1.125%, respectively, at March 31, 2019. Based on our credit ratings, a 0.175% commitment fee was charged on the unused amount at March 31, 2019.

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 payments under the CP Program during the three months ended March 31, 2019 were $21 million and our notes outstanding as of March 31, 2019 were $165 million. As of March 31, 2019, the weighted average interest rate on CP Program borrowings was 2.70%. As of March 31, 2019, we had outstanding letters of credit of totaling approximately $14 million.

Debt Covenants

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 was calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit and certain guarantees issued, by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interest in subsidiaries.

Our Revolving Credit Facility and term loans require compliance with the following financial covenant at the end of each quarter:

	As of March 31, 2019	Covenant Requirement	
Consolidated Indebtedness to Capitalization Ratio	58.1%	Less than	65%

As of March 31, 2019, we were in compliance with this covenant.

(9) EQUITY

A summary of the changes in equity is as follows:

Three Months Ended March 31, 2019	Common Stock		Treasury Stock						
(in thousands except share amounts)	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Non controlling Interest	Total
December 31, 2018	60,048,567	$ 60,049	44,253	$ (2,510)	$ 1,450,569	$ 700,396	$ (26,916)	$ 105,835	$ 2,287,423
Net income (loss) available for common stock	—	—	—	—	—	103,808	—	3,554	107,362
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	457	—	457
Dividends on common stock ($0.505 per share)	—	—	—	—	—	(30,332)	—	—	(30,332)
Share-based compensation	48,956	49	(20,497)	1,078	(589)	—	—	—	538
Issuance of common stock	280,497	280	—	—	19,719	—	—	—	19,999
Issuance costs	—	—	—	—	(289)	—	—	—	(289)
Cumulative effect of ASU 2016-02, *Leases* implementation	—	—	—	—	—	3,390	—	—	3,390
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(4,846)	(4,846)
March 31, 2019	60,378,020	$ 60,378	23,756	$ (1,432)	$ 1,469,410	$ 777,262	$ (26,459)	$ 104,543	$ 2,383,702

Three Months Ended March 31, 2018	Common Stock		Treasury Stock						
(in thousands except share amounts)	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Non controlling Interest	Total
December 31, 2017	53,579,986	$ 53,580	39,064	$ (2,306)	$ 1,150,285	$ 548,617	$ (41,202)	$ 111,232	$ 1,820,206
Net income (loss) available for common stock	—	—	—	—	—	133,004	—	3,630	136,634
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	1,260	—	1,260
Dividends on common stock ($0.475 per share)	—	—	—	—	—	(25,444)	—	—	(25,444)
Share-based compensation	64,770	65	14,895	(743)	1,433	—	—	—	755
Dividend reinvestment and stock purchase plan	4,061	4	—	—	215	—	—	—	219
Other stock transactions	—	—	—	—	—	(16)	18	—	2
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(5,648)	(5,648)
March 31, 2018	53,648,817	$ 53,649	53,959	$ (3,049)	$ 1,151,933	$ 656,161	$ (39,924)	$ 109,214	$ 1,927,984

At-the-Market Equity Offering Program

Our ATM equity offering program allows us to sell shares of our common stock with an aggregate value of up 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. During the three months ended March 31, 2019, we issued a total of 280,497 shares of common stock under the ATM equity offering program for $20 million, net of $0.2 million in commissions. As of March 31, 2019, there were no shares that were sold, but not settled.

(10) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk and Credit Policies and Procedures as discussed in our 2018 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, 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.

Credit Risk

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

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

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

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

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 2019 through May 2021; a portion of these 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 gain or loss on these designated derivatives is reported in AOCI in the accompanying Condensed Consolidated Balance Sheets. Effectiveness of our hedged 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, 2019		December 31, 2018		March 31, 2018	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	3,120,000	21	4,000,000	24	6,760,000	33
Natural gas options purchased, net	1,150,000	10	4,320,000	13	170,000	11
Natural gas basis swaps purchased	3,020,000	21	3,960,000	24	6,770,000	33
Natural gas over-the-counter swaps, net [(b)]	3,316,000	26	3,660,000	24	2,760,000	26
Natural gas physical contracts, net [(c)]	2,786,980	12	18,325,852	30	386,250	32

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(a) Term reflects the maximum forward period hedged.
(b) As of March 31, 2019, 534,000 MMBtus were designated as cash flow hedges.
(c) Volumes exclude contracts that qualify for the normal purchase, normal sales exception.

Based on March 31, 2019 prices, a $0.1 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.

We have certain derivative contracts which contain credit provisions. These credit provisions may require the Company to post collateral when credit exposure to the Company is in excess of a negotiated line of unsecured credit. At March 31, 2019, the Company posted $0.2 million related to such provisions, which is included in Other current assets on the Condensed Consolidated Balance Sheets.

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, 2019 and 2018. Note that this presentation does not reflect gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic profit or loss we realized when the underlying physical and financial transactions were settled.

Three Months Ended March 31, 2019
(in thousands)

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income
Interest rate swaps	Interest expense	$ (713)
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	554
Total		$ (159)

Three Months Ended March 31, 2018
(in thousands)

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income
Interest rate swaps	Interest expense	$ (713)
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(621)
Total		$ (1,334)

The following tables summarize 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, 2019 and 2018.

	Three Months Ended March 31,	
	2019	2018
	(in thousands)	
Increase (decrease) in fair value:		
Forward commodity contracts	$ 234	$ (297)
Recognition of (gains) losses in earnings due to settlements:		
Interest rate swaps	713	713
Forward commodity contracts	(554)	621
Total other comprehensive income (loss) from hedging	$ 393	$ 1,037

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, 2019 and 2018 (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 profit or loss we realized when the underlying physical and financial transactions were settled.

		Three Months Ended March 31,	
		2019	2018
Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	$ 25	$ 254
		$ 25	$ 254

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 $3.9 million, $6.2 million and $11 million at March 31, 2019, December 31, 2018 and March 31, 2018, respectively.

(11) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

The accounting guidance for fair value measurements requires certain disclosures about assets and liabilities measured at fair value. This guidance establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments. For additional information, see Notes 1, 9, 10 and 11 to the Consolidated Financial Statements included in our 2018 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

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.

Recurring Fair Value Measurements

	As of March 31, 2019				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Utilities	$ —	$ 1,375	$ —	$ (388)	$ 987
Total	$ —	$ 1,375	$ —	$ (388)	$ 987
Liabilities:					
Commodity derivatives — Utilities	$ —	$ 4,122	$ —	$ (4,009)	$ 113
Total	$ —	$ 4,122	$ —	$ (4,009)	$ 113

	As of December 31, 2018				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Utilities	$ —	$ 2,927	$ —	$ (1,408)	$ 1,519
Total	$ —	$ 2,927	$ —	$ (1,408)	$ 1,519
Liabilities:					
Commodity derivatives — Utilities	$ —	$ 6,801	$ —	$ (5,794)	$ 1,007
Total	$ —	$ 6,801	$ —	$ (5,794)	$ 1,007

	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

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 table presents the fair value and balance sheet classification of our derivative instruments (in thousands) as of:

	Balance Sheet Location	March 31, 2019	December 31, 2018	March 31, 2018
Derivatives designated as hedges:				
Asset derivative instruments:				
Current commodity derivatives	Derivative assets — current	$ 131	$ 415	$ —
Noncurrent commodity derivatives	Other assets, non-current	9	18	—
Liability derivative instruments:				
Current commodity derivatives	Derivative liabilities — current	(11)	(114)	(394)
Noncurrent commodity derivatives	Other deferred credits and other liabilities	—	(4)	(29)
Total derivatives designated as hedges		$ 129	$ 315	$ (423)
Derivatives not designated as hedges:				
Asset derivative instruments:				
Current commodity derivatives	Derivative assets — current	$ 801	$ 1,085	$ 295
Noncurrent commodity derivatives	Other assets, non-current	46	1	—
Liability derivative instruments:				
Current commodity derivatives	Derivative liabilities — current	(84)	(833)	(497)
Noncurrent commodity derivatives	Other deferred credits and other liabilities	(18)	(56)	(164)
Total derivatives not designated as hedges		$ 745	$ 197	$ (366)

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 2018 Annual Report on Form 10-K.

(12) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	March 31, 2019		December 31, 2018		March 31, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [a]	$ 12,225	$ 12,225	$ 20,776	$ 20,776	$ 30,947	$ 30,947
Restricted cash [a]	$ 3,494	$ 3,494	$ 3,369	$ 3,369	$ 2,958	$ 2,958
Notes payable [b]	$ 164,650	$ 164,650	$ 185,620	$ 185,620	$ 164,200	$ 164,200
Long-term debt, including current maturities [c] [d]	$ 2,956,042	$ 3,137,538	$ 2,956,578	$ 3,039,108	$ 3,114,530	$ 3,265,965

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

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

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

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

(13) OTHER COMPREHENSIVE INCOME (LOSS)

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

The following table details reclassifications out of AOCI and into net income. The amounts in parentheses below indicate decreases to net income in the 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, 2019	Amount Reclassified from AOCI Three Months Ended March 31, 2018
Gains and (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$ (713)	$ (713)
Commodity contracts	Fuel, purchased power and cost of natural gas sold	554	(621)
		(159)	(1,334)
Income tax	Income tax benefit (expense)	35	297
Total reclassification adjustments related to cash flow hedges, net of tax		$ (124)	$ (1,037)
Amortization of components of defined benefit plans:			
Prior service cost	Operations and maintenance	$ 19	$ 45
Actuarial gain (loss)	Operations and maintenance	(220)	(622)
		(201)	(577)
Income tax	Income tax benefit (expense)	48	126
Total reclassification adjustments related to defined benefit plans, net of tax		$ (153)	$ (451)
Total reclassifications		$ (277)	$ (1,488)

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

	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2018	$ (17,307)	$ 328	$ (9,937)	$ (26,916)
Other comprehensive income (loss) before reclassifications	—	180	—	180
Amounts reclassified from AOCI	550	(426)	153	277
As of March 31, 2019	$ (16,757)	$ 82	$ (9,784)	$ (26,459)

	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
Balance 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
As of March 31, 2018	$ (19,005)	$ (270)	$ (20,649)	$ (39,924)

(14) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Three Months Ended	March 31, 2019	March 31, 2018
	(in thousands)	
Non-cash investing and financing activities —		
Property, plant and equipment acquired with accrued liabilities	$ 56,571	$ 21,708
Cash (paid) refunded during the period —		
Interest (net of amounts capitalized)	$ (30,672)	$ (36,928)
Income taxes	$ 8	$ (14,336)

(15) 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,	
	2019	2018
Service cost	$ 1,346	$ 1,708
Interest cost	4,343	3,867
Expected return on plan assets	(6,100)	(6,185)
Prior service cost	6	15
Net loss (gain)	941	2,158
Net periodic benefit cost	$ 536	$ 1,563

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,	
	2019	2018
Service cost	$ 454	$ 573
Interest cost	560	521
Expected return on plan assets	(57)	(57)
Prior service cost (benefit)	(99)	(99)
Net loss (gain)	—	54
Net periodic benefit cost	$ 858	$ 992

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,	
	2019	2018
Service cost [(a)]	$ 1,285	$ 280
Interest cost	324	293
Net loss (gain)	134	250
Net periodic benefit cost	$ 1,743	$ 823

(a) The increase in service cost for the three months ended March 31, 2019 compared to the same period in 2018 is primarily driven by market returns.

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 2019 and anticipated contributions for 2019 and 2020 are as follows (in thousands):

	Contributions Made Three Months Ended March 31, 2019	Additional Contributions Anticipated for 2019	Contributions Anticipated for 2020
Defined Benefit Pension Plan	$ —	$ 12,700	$ 12,700
Non-pension Defined Benefit Postretirement Healthcare Plans	$ 1,109	$ 3,326	$ 4,271
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$ 366	$ 1,097	$ 1,562

(16) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2018 Annual Report on Form 10-K except for those described below.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of March 31, 2019, 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 in 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, 2019, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

(17) 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. Assets and liabilities of the discontinued operations have been reclassified and reflected on the accompanying Condensed Consolidated Balance Sheets as “Current assets held for sale” and “Current 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. We completed the divestiture of our Oil and Gas segment in 2018.

Total assets and liabilities of our Oil and Gas segment at March 31, 2018 were classified as Current assets held for sale and Current liabilities held for sale on the accompanying Condensed Consolidated Balance Sheets due to the final disposals occurring in 2018.

(in thousands)	As of March 31, 2018
Other current assets	$ 4,332
Deferred income tax assets, noncurrent, net	3,739
Property, plant and equipment, net	16,653
Other current liabilities	(17,233)
Other noncurrent liabilities	(7,677)
Net (liabilities)	$ (186)

(18) INCOME TAXES

Income tax benefit (expense), net for the three months ended March 31, 2019 was $(17) million compared to $26 million reported for the same period in 2018. The increase in tax expense was primarily due to:

- A prior year $49 million tax benefit resulting from legal entity restructuring, partially offset by:
    - A prior year $2.3 million income tax expense associated with changes in the prior estimated impact of tax reform on deferred income taxes; and
    - A current year $3.4 million increase in income tax benefit from forecasted federal production tax credits and state investment tax credits as well as $1.8 million of income tax benefit for deferred tax amortization related to tax reform (which is offset by reduced revenue at our utilities).

Prior year tax benefit related to legal restructuring

As part of the Company’s ongoing efforts to continue to integrate the legal entities that the Company acquired in recent years, certain legal entity restructuring transactions occurred on March 31, 2018. As a result of these transactions, $49 million of deferred income tax assets, 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.

Prior year TCJA expense

On December 22, 2017, the TCJA was signed into law reducing the federal corporate rate from 35% to 21% effective January 1, 2018. During the three months ended March 31, 2018, we recorded approximately $2.3 million of additional tax expense associated with changes in the prior estimated impacts of TCJA related items.

(19) ACCRUED LIABILITIES

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

	March 31, 2019	December 31, 2018	March 31, 2018
Accrued employee compensation, benefits and withholdings	$ 48,078	$ 63,742	$ 46,262
Accrued property taxes	43,662	42,510	42,912
Customer deposits and prepayments	39,125	43,574	35,748
Accrued interest and contract adjustment payments	35,149	31,759	30,426
CIAC current portion	1,485	1,485	1,552
Other (none of which is individually significant)	28,573	32,431	37,140
Total accrued liabilities	$ 196,072	$ 215,501	$ 194,040

(20) LEASES

Lessee

We lease from third parties certain office and operation center facilities, communication tower sites, equipment, and materials storage. Our leases have remaining lease terms ranging from less than one year to 37 years, including options to extend that are reasonably certain to be exercised.

The components of lease expense were as follows (in thousands):

	Income Statement Location	Three Months Ended March 31, 2019
Operating lease cost	Operations and maintenance	$ 311
Finance lease cost:		
Amortization of right-of-use asset	Depreciation, depletion and amortization	17
Interest on lease liabilities	Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	3
Total lease cost		$ 331

Supplemental balance sheet information related to leases was as follows (in thousands):

	Balance Sheet Location	As of March 31, 2019	
Assets:			
Operating lease assets	Other assets, non-current	$	5,331
Finance lease assets	Other assets, non-current		481
Total lease assets		$	5,812
Liabilities:			
Current:			
Operating leases	Accrued liabilities	$	974
Finance leases	Accrued liabilities		92
Noncurrent:			
Operating leases	Other deferred credits and other liabilities		4,563
Finance leases	Other deferred credits and other liabilities		391
Total lease liabilities		$	6,020

Supplemental cash flow information related to leases was as follows (in thousands):

	Three Months Ended March 31, 2019	
Cash paid included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	246
Operating cash flows from finance lease	$	3
Financing cash flows from finance lease	$	15
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$	2,328
Finance leases	$	—

	As of March 31, 2019
Weighted average remaining lease term (years):	
Operating leases	8 years
Finance leases	5 years
Weighted average discount rate:	
Operating leases	4.23%
Finance leases	4.21%

As of March 31, 2019, scheduled maturities of lease liabilities for future years were as follows (in thousands):

	Operating Leases	Finance Leases	Total
2019 [(a)]	$ 952	$ 83	$ 1,035
2020	936	111	1,047
2021	820	111	931
2022	698	111	809
2023	699	110	809
Thereafter	2,653	9	2,662
Total lease payments [(b)]	$ 6,758	$ 535	$ 7,293
Less imputed interest	1,221	52	1,273
Present value of lease liabilities	$ 5,537	$ 483	$ 6,020

(a) Includes lease liabilities for the remaining nine months of 2019.
(b) Lease payments exclude payments to landlords for common area maintenance, real estate taxes, and insurance.

As previously disclosed in Note 14 of the Notes to the Consolidated Financial Statements in our 2018 Annual Report on Form 10-K, prior to the adoption of ASU 2016-02, *Leases (Topic 842)*, the future minimum payments required under operating lease agreements as of December 31, 2018 were as follows (in thousands):

	Operating Leases
2019	$ 1,052
2020	464
2021	344
2022	224
2023	216
Thereafter	1,776
Total lease payments	$ 4,076

Lessor

We lease to third parties certain generating station ground leases, communication tower sites, and natural gas pipeline. These leases have remaining terms ranging from less than one year to 35 years.

The components of lease revenue were as follows (in thousands):

	Income Statement Location	Three Months Ended March 31, 2019
Operating lease income	Revenue	$ 638

As of March 31, 2019, scheduled maturities of lease receivables for future years were as follows (in thousands):

		Operating Leases
2019 [(a)]	$	1,652
2020		2,010
2021		1,843
2022		1,793
2023		1,799
Thereafter		55,481
Total lease receivables	$	64,578

(a) Includes lease receivables for the remaining nine months of 2019.

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 212,000 customers in Colorado, Montana, South Dakota and Wyoming. 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 1,054,000 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 47,000 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 62,000 and 28,000 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.

Accounting standards for presentation of segments requires an approach based on the way we organize the segments for making operating decisions and how the chief operating decision maker (CODM) assesses performance. We have changed our segment performance metrics and concluded that adjusted operating income, instead of net income available for common stock that was used previously, is the most relevant metric for measuring segment performance.

The CODM assesses the performance of our segments by using adjusted operating income, which considers the power sales arrangement between Colorado IPP and Colorado Electric be treated as an executory contract. Adjusted operating income adjusts this power sales arrangement from being accounted for as a capital lease to being accounted for as an executory contract on an accrual basis. This adjustment impacts Electric Utilities and Power Generation segments and Corporate and Other. There were no adjustments to Gas Utilities and Mining segments and this adjustment had no effect on our consolidated operating income.

The change to our segment performance measure resulted in a revision of the Company’s segment disclosures for all periods to report adjusted operating income as the measure of segment profit and adjust operating income for the power sales agreement as an executory contract and not a capital lease.

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. 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, 2019 and 2018, and our financial condition as of March 31, 2019, December 31, 2018 and March 31, 2018, 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 53.

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, 2019 Compared to Three Months Ended March 31, 2018. Net income from continuing operations available for common stock for the three months ended March 31, 2019 was $104 million, or $1.73 per diluted share, compared to $135 million, or $2.50 per diluted share, reported for the same period in 2018. The variance to the prior year included the following:

- Electric Utilities' adjusted operating income increased $2.5 million primarily due to favorable winter weather compared to prior year partially offset by higher operating expenses driven by outside services and employee costs;
- Gas Utilities' operating income increased $7.9 million primarily due to new rates and favorable winter weather compared to prior year partially offset by higher operating expenses driven by outside services and employee costs; and
- A prior year $49 million tax benefit resulting from legal entity restructuring partially offset by:
    - A prior year $2.3 million income tax expense associated with changes in the prior estimated impact of tax reform on deferred income taxes; and
    - A current year $3.4 million increase in income tax benefit from forecasted federal production tax credits and state investment tax credits as well as $1.8 million of income tax benefit for deferred tax amortization related to tax reform (which is offset by reduced revenue at our utilities).

Net income available for common stock for the three months ended March 31, 2019 was $104 million, or $1.73 per diluted share, compared to $133 million, or $2.46 per diluted share reported for the same period in 2018. (Loss) from discontinued operations for the three months ended March 31, 2018 was $(2.3) million or $(0.04). There was no (Loss) from discontinued operations for the three months ended March 31, 2019.

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

	Three Months Ended March 31,		
	2019	2018	Variance
Revenue			
Revenue	$ 635,681	$ 611,966	$ 23,715
Inter-company eliminations	(37,871)	(36,577)	(1,294)
	$ 597,810	$ 575,389	$ 22,421
Adjusted operating income [(a)]			
Electric Utilities	$ 41,020	$ 38,480	$ 2,540
Gas Utilities	103,314	95,443	7,871
Power Generation	11,967	11,776	191
Mining	4,337	4,271	66
Corporate and Other	(507)	(1,696)	1,189
Operating income	160,131	148,274	11,857
Interest expense, net	(34,717)	(34,995)	278
Other income (expense), net	(789)	(104)	(685)
Income tax benefit (expense) [(b) (c)]	(17,263)	25,802	(43,065)
Income from continuing operations	107,362	138,977	(31,615)
Net (loss) from discontinued operations	—	(2,343)	2,343
Net income	107,362	136,634	(29,272)
Net income attributable to noncontrolling interest	(3,554)	(3,630)	76
Net income available for common stock	$ 103,808	$ 133,004	$ (29,196)
Amounts attributable to common shareholders:			
Net income from continuing operations available for common stock	$ 103,808	$ 135,347	$ (31,539)
Net (loss) from discontinued operations	—	(2,343)	2,343
Net income available for common stock	$ 103,808	$ 133,004	$ (29,196)

(a) Due to changes to our segment performance measure, Adjusted operating income was recast for the three months ended March 31, 2018 for Electric Utilities and Power Generation segments and Corporate and Other. These changes had no impact on our consolidated financial results. See segment discussions in the sections below for more information.

(b) Income tax benefit (expense) for the three months ended March 31, 2019 included a $3.4 million increase in income tax benefit from forecasted federal production tax credits and state investment tax credits as well as $1.8 million of income tax benefit for deferred tax amortization related to tax reform (which is offset by reduced revenue at our utilities).

(c) Income tax benefit (expense) for the three months ended March 31, 2018 included a $49 million tax benefit resulting from legal entity restructuring and $2.3 million of income tax expense associated with changes in the prior estimated impact of tax reform on deferred income taxes.

Overview of Business Segments and Corporate Activity

Electric Utilities Segment

- Electric Utilities experienced colder winter weather during the three months ended March 31, 2019 compared to the same period in 2018. Heating degree days for the three months ended March 31, 2019 were 7% higher than normal, compared to 1% higher than normal for the same period in 2018.

Gas Utilities Segment

- Gas Utilities experienced colder winter weather during the three months ended March 31, 2019 compared to the same period in 2018. Heating degree days for the three months ended March 31, 2019 were 11% higher than normal, compared to 2% higher than normal for the same period in 2018.

- Regulatory activity:

  - On March 29, 2019, Nebraska Gas filed an application with the NPSC to consolidate its two gas distribution utilities into a new public utility entity. The filing also requests to consolidate the terms and conditions of the existing tariffs of the two utilities into a single tariff.

  - On March 6, 2019, Wyoming Gas filed an application with the WPSC to consolidate its four gas distribution utilities into a new public utility entity. The filing also requests the new entity adopt the terms and conditions of the existing tariffs.

  - On February 1, 2019, Colorado Gas filed a rate review with the CPUC requesting approval to consolidate the base rate areas, tariffs, terms and conditions and adjustment clauses of its two legacy utilities. The rate review also requests $2.5 million in new revenue to recover costs and investments in safety, reliability and system integrity.

Power Generation Segment

- On March 11, 2019, Black Hills Electric Generation commenced construction on the $71 million, 60-megawatt Busch Ranch II Wind Farm. The wind farm is expected to be completed and in service in 2019.

Corporate and Other

- On April 30, 2019, S&P affirmed South Dakota Electric's credit rating at A.

- During the three months ended March 31, 2019, we issued a total of 280,497 shares of common stock for net proceeds of approximately $20 million through our ATM equity offering program.

- On February 28, 2019, S&P affirmed our BBB+ rating and maintained a Stable outlook.

Operating Results

A discussion of operating results from our segments and Corporate activities follows in the sections below. 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 and amortization 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 and natural gas purchases 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,		
	2019	2018	Variance
	(in thousands)		
Revenue	$ 182,927	$ 173,555	$ 9,372
Total fuel and purchased power	73,283	68,738	4,545
Gross margin (non-GAAP)	109,644	104,817	4,827
Operations and maintenance	47,144	45,093	2,051
Depreciation and amortization	21,480	21,244	236
Total operating expenses	68,624	66,337	2,287
Adjusted operating income [(a)]	$ 41,020	$ 38,480	$ 2,540

(a) Due to changes to our segment performance measure, Adjusted operating income was recast for the three months ended 2018, which resulted in a change of $1.7 million. The impact to Adjusted operating income for the three months ended March 31, 2019 was ($5.4) million. There was no impact on our consolidated Operating income.

Results of Operations for the Electric Utilities for the Three Months Ended March 31, 2019 Compared to the Three Months Ended March 31, 2018:

Gross margin for the three months ended March 31, 2019 increased as a result of the following:

	(in millions)
Reduction in purchased power capacity charges	$ 1.6
Off-system power marketing	1.3
Weather	0.6
Rider recovery	0.4
Residential customer growth	0.3
Other	0.6
Total increase in Gross margin (non-GAAP)	$ 4.8

Operations and maintenance increased primarily due to higher outside services expenses and higher employee costs driven by labor and benefits.

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

Operating Statistics

	Electric Revenue (in thousands)		Quantities sold (MWh)	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2019	2018	2019	2018
Residential	$ 57,638	$ 55,741	389,178	383,270
Commercial	60,963	61,984	505,573	500,136
Industrial	32,440	30,800	426,614	400,709
Municipal	4,139	4,141	36,636	36,324
Subtotal Retail Revenue - Electric	155,180	152,666	1,358,001	1,320,439
Contract Wholesale	8,343	9,050	223,020	237,704
Off-system/Power Marketing Wholesale	6,692	4,144	140,850	129,041
Other	12,712	7,695	—	—
Total Revenue and Energy Sold	182,927	173,555	1,721,871	1,687,184
Other Uses, Losses or Generation, net	—	—	97,000	90,855
Total Revenue and Energy	182,927	173,555	1,818,871	1,778,039
Less cost of fuel and purchased power [(a)]	73,283	68,738		
Gross Margin (non-GAAP) [(a)]	$ 109,644	$ 104,817		

(a) Due to changes to our segment performance measure, Fuel and purchased power was recast for the three months ended March 31, 2018, which resulted in a change of $1.6 million. The impact to Fuel and purchased power for the three months ended March 31, 2019 was $8.7 million. There were corresponding changes to Gross margin for each period.

	Electric Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Quantities Sold (MWh) [(a)]	
Three Months Ended March 31,	2019	2018	2019	2018	2019	2018
Colorado Electric [(b)]	$ 59,847	$ 58,353	$ 31,444	$ 31,746	491,682	487,000
South Dakota Electric	79,041	73,815	56,308	51,376	845,001	828,177
Wyoming Electric	44,039	41,387	21,892	21,695	482,188	462,862
Total Electric Revenue, Gross Margin (non-GAAP), and Quantities Sold	$ 182,927	$ 173,555	$ 109,644	$ 104,817	1,818,871	1,778,039

(a) Total MWh for 2019 includes Other Uses, Losses or Generation, net, which are approximately 5%, 5%, and 6% for Colorado Electric, South Dakota Electric, and Wyoming Electric, respectively.
(b) Due to changes to our segment performance measure, Gross margin was recast for the three months ended March 31, 2018, which resulted in a change of ($1.6) million. The impact to Gross margin for the three months ended March 31, 2019 was ($8.7) million.

	Three Months Ended March 31,	
Quantities Generated and Purchased (MWh)	2019	2018
Coal-fired	585,295	595,600
Natural Gas and Oil	124,657	41,323
Wind	55,419	73,981
Total Generated	765,371	710,904
Purchased	1,053,500	1,067,135
Total Generated and Purchased	1,818,871	1,778,039

Quantities Generated and Purchased (MWh)	Three Months Ended March 31, 2019	2018
Generated:		
Colorado Electric	100,530	92,048
South Dakota Electric	457,369	412,194
Wyoming Electric	207,472	206,662
Total Generated	765,371	710,904
Purchased:		
Colorado Electric	391,152	394,952
South Dakota Electric	387,632	415,983
Wyoming Electric	274,716	256,200
Total Purchased	1,053,500	1,067,135
Total Generated and Purchased	1,818,871	1,778,039

	Three Months Ended March 31, 2019			2018	
Heating Degree Days	Actual	Variance from Normal	Actual Variance to Prior Year	Actual	Variance from Normal
Colorado Electric	2,549	(4)%	6%	2,406	(9)%
South Dakota Electric	3,916	22 %	6%	3,699	15 %
Wyoming Electric	3,198	— %	7%	2,984	(7)%
Combined [(a)]	3,147	7 %	6%	2,964	1 %

(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, 2019	2018
Coal-fired plants	96.2%	95.0%
Natural gas-fired plants and Other plants	90.7%	96.5%
Wind	96.8%	97.1%
Total availability	92.9%	96.1%
Wind capacity factor	42.6%	50.4%

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 2018 Annual Report on Form 10-K filed with the SEC.

Gas Utilities

	Three Months Ended March 31,		
	2019	2018	Variance
	(in thousands)		
Revenue:			
Natural gas - regulated	$ 383,875	$ 370,268	$ 13,607
Other - non-regulated services	27,205	27,076	129
Total revenue	411,080	397,344	13,736
Cost of sales:			
Natural gas - regulated	201,050	205,084	(4,034)
Other - non-regulated services	6,229	4,601	1,628
Total cost of sales	207,279	209,685	(2,406)
Gross margin (non-GAAP)	203,801	187,659	16,142
Operations and maintenance	77,938	70,906	7,032
Depreciation and amortization	22,549	21,310	1,239
Total operating expenses	100,487	92,216	8,271
Adjusted operating income	$ 103,314	$ 95,443	$ 7,871

Results of Operations for the Gas Utilities for the Three Months Ended March 31, 2019 Compared to the Three Months Ended March 31, 2018:

Gross margin for the three months ended March 31, 2019 increased as a result of:

	(in millions)
New rates	$ 8.9
Weather [(a)]	5.2
Customer growth - distribution	1.8
Transport and transmission	1.7
Other	0.9
Excess deferred taxes returned to customers	(2.4)
Total increase in Gross margin (non-GAAP)	$ 16.1

(a) Heating degree days at the Gas Utilities for the three months ended March 31, 2019 were 11% higher than normal compared to 2% higher than normal in the same period in the prior year.

Operations and maintenance increased primarily due to $3.3 million of higher outside services expenses and $2.3 million of higher employee costs driven by labor, benefits and additional headcount. Various other 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 previous year capital expenditures.

Operating Statistics

	Gas Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Gas Utilities Quantities Sold & Transported (Dth)	
	Three Months Ended March 31,		Three Months Ended March 31,		Three Months Ended March 31,	
	2019	2018	2019	2018	2019	2018
Residential	$ 241,129	$ 234,751	$ 105,057	$ 96,777	32,838,018	30,096,237
Commercial	96,139	95,005	35,158	32,203	14,990,848	13,949,121
Industrial	6,014	5,982	2,017	1,674	1,182,527	1,183,617
Other [(a)]	(4,354)	(7,531)	(4,354)	(7,531)	—	—
Total Distribution	338,928	328,207	137,878	123,123	49,011,393	45,228,975
Transportation and Transmission	44,947	42,061	44,947	42,061	46,316,160	44,733,475
Total Regulated	383,875	370,268	182,825	165,184	95,327,553	89,962,450
Non-regulated Services	27,205	27,076	20,976	22,475		
Total Gas Revenue & Gross Margin (non-GAAP)	$ 411,080	$ 397,344	$ 203,801	$ 187,659		

(a) Includes 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 (non-GAAP) (in thousands)		Gas Utilities Quantities Sold & Transported (Dth)	
	Three Months Ended March 31,		Three Months Ended March 31,		Three Months Ended March 31,	
	2019	2018	2019	2018	2019	2018
Arkansas	$ 79,391	$ 70,388	$ 44,282	$ 35,917	12,424,196	11,878,626
Colorado	76,471	71,398	37,600	33,145	13,176,925	11,703,351
Iowa	65,641	67,884	23,050	22,426	15,663,687	15,502,989
Kansas	41,217	42,381	18,119	17,897	10,443,270	10,297,328
Nebraska	108,797	106,761	56,073	53,860	28,999,018	27,987,224
Wyoming	39,563	38,532	24,677	24,414	14,620,457	12,592,932
Total Gas Revenue & Gross Margin (non-GAAP)	$ 411,080	$ 397,344	$ 203,801	$ 187,659	95,327,553	89,962,450

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.

	Three Months Ended March 31,				
	2019			2018	
Heating Degree Days	Actual	Variance from Normal	Actual Variance to Prior Year	Actual	Variance from Normal
Arkansas [(a)]	2,101	—%	3%	2,048	(3)%
Colorado	3,030	3%	12%	2,704	(8)%
Iowa	3,830	14%	8%	3,531	5%
Kansas [(a)]	2,779	13%	13%	2,470	—%
Nebraska	3,483	15%	9%	3,207	6%
Wyoming	3,513	10%	8%	3,244	1%
Combined [(b)]	3,449	11%	9%	3,159	2%

(a) Arkansas and Kansas have weather normalization mechanisms that mitigate the weather impact on gross margins.

(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas due to its weather normalization mechanism. Arkansas is 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 2018 Annual Report on Form 10-K filed with the SEC.

Power Generation

	Three Months Ended March 31,		
	2019	2018	Variance
	(in thousands)		
Revenue	$ 25,245	$ 23,939	$ 1,306
Operations and maintenance	8,688	8,127	561
Depreciation and amortization	4,590	4,036	554
Total operating expense	13,278	12,163	1,115
Adjusted operating income [(a)]	$ 11,967	$ 11,776	$ 191

(a) Due to changes to our segment performance measure, Adjusted operating income was recast for the three months ended March 31, 2018, which resulted in a change of ($1.6) million. The impact to Adjusted operating income for the three months ended March 31, 2019 was $0.7 million. There was no impact on our consolidated Operating income.

Results of Operations for Power Generation for the Three Months Ended March 31, 2019 Compared to the Three Months Ended March 31, 2018: Revenue increased in the current year due to increased wind megawatt hours sold and higher power purchase agreement prices. Operating expenses increased in the current year due to higher employee costs and higher depreciation from new wind assets.

The following table summarizes MWh for our Power Generation segment:

	Three Months Ended March 31,	
	2019	2018
Quantities Sold, Generated and Purchased (MWh) [(a)]		
Sold		
Black Hills Colorado IPP [(b)]	205,973	232,375
Black Hills Wyoming [(c)]	164,049	165,601
Black Hills Electric Generation [(d)]	12,864	—
Total Sold	382,886	397,976
Generated		
Black Hills Colorado IPP [(b)]	205,973	232,375
Black Hills Wyoming [(c)]	132,593	134,029
Black Hills Electric Generation [(d)]	12,864	—
Total Generated	351,430	366,404
Purchased		
Black Hills Wyoming [(c)]	25,579	31,917
Total Purchased	25,579	31,917

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(a) Company uses and losses are not included in the quantities sold, generated, and purchased.
(b) Decrease from the prior year is a result of the impact of Colorado Electric's wind generation replacing natural-gas generation.
(c) Under the 20-year economy energy PPA with the City of Gillette effective September 2014, Black Hills Wyoming purchases energy on behalf of the City of Gillette and sells that energy to the City of Gillette. MWh sold may not equal MWh generated and purchased due to a dispatch agreement Black Hills Wyoming has with South Dakota Electric to cover energy imbalances.
(d) Increase from prior year is driven primarily by Black Hills Electric Generation's acquisition of a 50% ownership interest in Busch Ranch I on December 11, 2018.

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

	Three Months Ended March 31,	
	2019	2018
Contracted power plant fleet availability:		
Coal-fired plant	94.8%	94.7%
Natural gas-fired plants	95.6%	99.5%
Wind [(a)]	90.4%	N/A
Total availability	94.1%	98.3%

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(a) Black Hills Electric Generation acquired a 50% ownership interest in Busch Ranch I on December 11, 2018.

Mining

	Three Months Ended March 31,		
	2019	2018	Variance
	(in thousands)		
Revenue	$ 16,429	$ 17,128	$ (699)
Operations and maintenance	9,913	10,922	(1,009)
Depreciation, depletion and amortization	2,179	1,935	244
Total operating expenses	12,092	12,857	(765)
Adjusted operating income	$ 4,337	$ 4,271	$ 66

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

	Three Months Ended March 31,	
	2019	2018
Tons of coal sold	997	1,078
Cubic yards of overburden moved	1,994	2,022
Revenue per ton	$ 15.87	$ 15.89

Results of Operations for Mining for the Three Months Ended March 31, 2019 Compared to the Three Months Ended March 31, 2018:

Current year revenue decreased due to 8% fewer tons sold driven by a planned outage at the Wyodak power plant. Operating expenses decreased primarily due to lower royalties and production taxes on decreased revenues, and lower major maintenance expenses.

Corporate and Other

	Three Months Ended March 31,		
	2,019	2.018	Variance
	(in thousands)		
Adjusted operating (loss) [(a)]	$ (507)	$ (1,696)	$ 1,189

(a) Due to changes to our segment performance measure, Adjusted operating loss was recast for the three months ended March 31, 2018, which results in a change of ($0.1) million. The impact to Adjusted operating loss for the three months ended March 31, 2019 was $4.7 million. There was no impact on our consolidated Operating income.

Results of Operations for Corporate and Other for the Three Months Ended March 31, 2019 Compared to the Three Months Ended March 31, 2018:

The variance in Adjusted operating loss was primarily due to prior year expenses related to the oil and gas segment that were not reclassified to discontinued operations.

Consolidated interest expense, Other income (expense) and Income tax (expense) benefit

Interest Expense

Interest expense, net for the three months ended March 31, 2019 was $35 million compared to $35 million for the same period in 2018.

Other (Expense) Income

Other (expense) income, net for the three months ended March 31, 2019 was $(0.8) million compared to $(0.1) million for the same period in 2018.

Income Tax Benefit (Expense)

Income tax benefit (expense), net for the three months ended March 31, 2019 was $(17) million compared to $26 million for the same period in 2018. The increase in tax expense was primarily due to:

- A prior year $49 million tax benefit resulting from legal entity restructuring partially offset by:
    - A prior year $2.3 million income tax expense associated with changes in the prior estimated impact of tax reform on deferred income taxes; and
    - A current year $3.4 million increase in income tax benefit from forecasted federal production tax credits and state investment tax credits as well as $1.8 million of income tax benefit for deferred tax amortization related to tax reform (which is offset by reduced revenue at our utilities).

Critical Accounting Estimates

There have been no material changes in our critical accounting estimates from those reported in our 2018 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 2018 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, 2019, we had sufficient liquidity to cover collateral that could be required to be posted under these contracts.

Income Tax

The TCJA required revaluation of federal deferred tax assets and liabilities using the new lower corporate tax rate of 21%.
We have reached agreements with regulators in six states and are working with regulators in our seventh state, as well as FERC regarding returning benefits to customers. Our working capital requirements increased as a result of complying with the TCJA and providing the benefits of the TCJA to customers. This will negatively impact our cash flows by approximately $40 million to $45 million per year for each of the next several years.

Cash Flow Activities

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

Cash provided by (used in):	2019	2018	Variance
Operating activities	$ 175,893	$ 169,875	$ 6,018
Investing activities	$ (145,027)	$ (73,554)	$ (71,473)
Financing activities	$ (39,292)	$ (80,656)	$ 41,364

Year-to-Date 2019 Compared to Year-to-Date 2018

Operating Activities

Net cash provided by operating activities was $176 million for the three months ended March 31, 2019, compared to net cash provided by operating activities of $170 million for the same period in 2018 for an increase of $6 million. The variance was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $18 million higher for the three months ended March 31, 2019 compared to the same period in the prior year;

- Net cash outflows from changes in operating assets and liabilities were $15 million for the three months ended March 31, 2019, compared to net cash outflows of $1 million in the same period in the prior year. This $14 million increase was primarily due to:

    - Cash inflows increased by approximately $7 million primarily as a result of higher collections of accounts receivable, partially offset by higher materials inventory and natural gas in storage for the three months ended March 31, 2019 compared to the same period in the prior year;

    - Cash outflows decreased by approximately $29 million as a result of increases in accounts payable and accrued liabilities driven by working capital requirements; and

    - Cash inflows decreased by approximately $53 million as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and revenue reserved in the prior year due to the TCJA tax rate change that has subsequently been returned to customers.

Investing Activities

Net cash used in investing activities was $145 million for the three months ended March 31, 2019, compared to net cash used in investing activities of $74 million for the same period in 2018 for a variance of $71 million. The variance was primarily attributable to:

- Capital expenditures of approximately $144 million for the three months ended March 31, 2019 compared to $70 million for the same period in the prior year. Higher current year expenditures are driven by the Busch Ranch II wind project at our Power Generation segment and increased programmatic spending at our Gas and Electric Utilities; and

- A $24 million investment made in the prior year partially offset by a $20 million change in net cash provided by investing activities from discontinued operations primarily due to the prior year sale of assets held for sale.

Financing Activities

Net cash used in financing activities for the three months ended March 31, 2019 was $39 million, compared to $81 million of net cash used in financing activities for the same period in 2018 for a variance of $41 million. This variance is primarily due to:

- Lower current year net repayments of short-term borrowings of $26 million;

- Current year issuance of common stock for net proceeds of approximately $20 million through our ATM equity offering program; and

- $4.9 million of higher current year dividend payments.

Dividends

Dividends paid on our common stock totaled $30 million for the three months ended March 31, 2019, or $0.505 per share per quarter. On April 29, 2019, our board of directors declared a quarterly dividend of $0.505 per share payable June 1, 2019, equivalent to an annual dividend of $2.02 per share. The amount of any future cash dividends to be declared and paid, if any, will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our Revolving Credit Facility and our future business prospects.

Debt

Financing Transactions and Short-Term Liquidity

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

Revolving Credit Facility and CP Program

On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one-year extension options (subject to consent from lenders). This facility is similar to the former revolving credit facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. See Note 8 for more information.

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. See Note 8 for more information.

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

Credit Facility	Expiration	Current Capacity	Revolver Borrowings at March 31, 2019	CP Program Borrowings at March 31, 2019	Letters of Credit at March 31, 2019	Available Capacity at March 31, 2019
Revolving Credit Facility	July 30, 2023	$ 750	$ —	$ 165	$ 14	$ 571

The weighted average interest rate on CP Program borrowings at March 31, 2019 was 2.71%. Revolving Credit Facility and CP Program financing activity for the three months ended March 31, 2019 was (dollars in millions):

	For the Three Months Ended March 31, 2019
Maximum amount outstanding - commercial paper (based on daily outstanding balances)	$ 237
Maximum amount outstanding - revolving credit facility (based on daily outstanding balances)	$ —
Average amount outstanding - commercial paper (based on daily outstanding balances)	$ 172
Average amount outstanding - revolving credit facility (based on daily outstanding balances)	$ —
Weighted average interest rates - commercial paper	2.70%
Weighted average interest rates - revolving credit facility	—%

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on certain liens, restrictions on certain transactions, and maintenance of a certain Consolidated Indebtedness to Capitalization Ratio. Under the Revolving Credit Facility, our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness (which includes letters of credit and certain guarantees issued), by (ii) Capital, which is Consolidated Indebtedness plus Consolidated Net Worth (which excludes noncontrolling interests in subsidiaries. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of March 31, 2019.

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

Financing Activities

Financing activities for the three months ended March 31, 2019 consisted of the following:

- We issued a total of 280,497 shares of common stock under the ATM equity offering program for $20 million, net of $0.2 million in commissions. As of March 31, 2019, there were no shares that were sold, but not settled.

- Short-term borrowings from our CP Program.

Future Financing Plans

- Evaluating refinancing options for our $200 million senior notes due July 15, 2020 and the $300 million Corporate term loan due July 30, 2020.

- Continue our ATM equity offering program to issue an additional $60 to $80 million of common stock for the remainder of 2019.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act.

As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. See Note 16 for more information.

Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not comply with certain financial or other covenants.

Covenants within Wyoming Electric's financing agreements require Wyoming Electric to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of March 31, 2019, we were in compliance with these covenants.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2018 Annual Report on Form 10-K filed with the SEC.

Credit Ratings

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

The following table represents the credit ratings and outlook and risk profile of BHC at March 31, 2019:

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

(a) On February 28, 2019, S&P affirmed our BBB+ rating and maintained a Stable outlook.
(b) On December 12, 2018, Moody's affirmed our Baa2 rating and maintained a Stable outlook.
(c) On October 11, 2018, Fitch affirmed our BBB+ rating and maintained a Stable outlook.

The following table represents the credit ratings of South Dakota Electric at March 31, 2019:

Rating Agency	Senior Secured Rating
S&P [(a)]	A
Moody's [(b)]	A1
Fitch [(c)]	A

(a) On April 30, 2019, S&P affirmed A rating.
(b) On December 12, 2018, Moody's affirmed A1 rating.
(c) On October 11, 2018, Fitch affirmed A rating.

Capital Requirements

Capital Expenditures

	Actual	Planned	Planned	Planned	Planned	Planned
Capital Expenditures by Segment	Three Months Ended March 31, 2019 [(a)]	2019 [(b)]	2020	2021	2022	2023
(in millions)						
Electric Utilities [(c)]	$ 35	$ 205	$ 221	$ 203	$ 170	$ 137
Gas Utilities [(c)]	58	464	323	289	277	274
Power Generation	28	84	9	8	10	4
Mining	4	8	7	11	10	7
Corporate and Other	7	16	22	8	5	7
	$ 132	$ 777	$ 582	$ 519	$ 472	$ 429

(a) Expenditures for the three months ended March 31, 2019 include the impact of accruals for property, plant and equipment.
(b) Includes actual capital expenditures for the three months ended March 31, 2019.
(c) Planned capital expenditures increased for 2019 through 2023 primarily due to increased programmatic integrity spending.

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

Contractual Obligations

There have been no significant changes in contractual obligations from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2018 Annual Report on Form 10-K.

Guarantees

There have been no significant changes to guarantees from those previously disclosed in Note 20 of the Notes to the Consolidated Financial Statements in our 2018 Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the pronouncements reported in our 2018 Annual Report on Form 10-K filed with the SEC and those discussed in Note 1 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial position, results of operations, or cash flows.

FORWARD-LOOKING INFORMATION

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

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

Any forward-looking statement contained in this document speaks only as of the date the statement was made. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement was made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements described in our 2018 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2018 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q and other reports that we file with the SEC from time to time.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

Our utility customers are exposed to natural gas price volatility. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers’ underlying exposure to these fluctuations. We also reduce the commodity price risk in the unregulated area of our business by using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales. The fair value of our utilities’ derivative contracts is summarized below (in thousands) as of:

	March 31, 2019	December 31, 2018	March 31, 2018
Net derivative (liabilities) assets	$ (2,203)	$ (2,214)	$ (6,002)
Cash collateral offset in Derivatives	3,621	4,386	5,078
Cash collateral included in Other current assets	1,717	2,880	2,020
Net asset (liability) position	$ 3,135	$ 5,052	$ 1,096

Financing Activities

From time-to-time, we have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations and anticipated debt refinancings. At March 31, 2019, December 31, 2018 and March 31, 2018, we had no outstanding interest rate swap agreements.

ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) as of March 31, 2019. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective at March 31, 2019.

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

Changes in Internal Control over Financial Reporting

During the quarter ended March 31, 2019, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 2018 Annual Report on Form 10-K and Note 16 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 16 is incorporated by reference into this item.

ITEM 1A. Risk Factors

There are no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2018 Annual Report on Form 10-K filed with the SEC.

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

There were no unregistered securities sold during the three months ended March 31, 2019.

ITEM 4. Mine Safety Disclosures

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

ITEM 5. Other Information

None.

ITEM 6. Exhibits

Exhibit Number	Description
Exhibit 3.1*	Restated Articles of Incorporation of the Registrant dated January 30, 2018 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 5, 2018).
Exhibit 3.2*	Amended and Restated Bylaws of the Registrant dated April 24, 2017 (filed as Exhibit 3 to the Registrant's Form 8-K filed on April 28, 2017).
Exhibit 4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013). Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on January 13, 2016). Sixth Supplemental Indenture dated as of August 19, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on August 19, 2016). Seventh Supplemental Indenture dated as of August 17, 2018 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 17, 2018).
Exhibit 4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
Exhibit 4.3*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014). Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
Exhibit 4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.

Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 95	Mine Safety and Health Administration Safety Data.
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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

SIGNATURES

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

BLACK HILLS CORPORATION

/s/ Linden R. Evans

Linden R. Evans, President and
Chief Executive Officer

/s/ Richard W. Kinzley

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

Dated: May 3, 2019

Exhibit 31.1

CERTIFICATION

I, Linden R. Evans, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2019

/S/ LINDEN R. EVANS

Linden R. Evans

President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Richard W. Kinzley, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2019

/S/ RICHARD W. KINZLEY

Richard W. Kinzley
Senior Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Black Hills Corporation (the “Company”) on Form 10-Q for the period ended March 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Linden R. Evans, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: May 3, 2019

/S/ LINDEN R. EVANS

Linden R. Evans
President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Black Hills Corporation (the “Company”) on Form 10-Q for the period ended March 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Richard W. Kinzley, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: May 3, 2019

/S/ RICHARD W. KINZLEY

Richard W. Kinzley
Senior Vice President and Chief Financial Officer

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included below.

Mine Safety and Health Administration Safety Data

Safety is a core value at Black Hills Corporation and at each of its subsidiary operations. We have in place a comprehensive safety program that includes extensive health and safety training for all employees, site inspections, emergency response preparedness, crisis communications training, incident investigation, regulatory compliance training and process auditing, as well as an open dialogue between all levels of employees. The goals of our processes are to eliminate exposure to hazards in the workplace, ensure that we comply with all mine safety regulations, and support regulatory and industry efforts to improve the health and safety of our employees along with the industry as a whole.

Under the Dodd-Frank Act, each operator of a coal or other mine is required to include certain mine safety results in its periodic reports filed with the SEC. Our mining operation, consisting of Wyodak Coal Mine, is subject to regulation by the federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the “Mine Act”). Below we present the following information regarding certain mining safety and health matters for the three month period ended March 31, 2019. In evaluating this information, consideration should be given to factors such as: (i) the number of citations and orders will vary depending on the size of the coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process, are often reduced in severity and amount, and are sometimes dismissed. The information presented includes:

- Total number of violations of mandatory health and safety standards that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard under section 104 of the Mine Act for which we have received a citation from MSHA;

- Total number of orders issued under section 104(b) of the Mine Act;

- Total number of citations and orders for unwarrantable failure of the mine operator to comply with mandatory health and safety standards under section 104(d) of the Mine Act;

- Total number of imminent danger orders issued under section 107(a) of the Mine Act; and

- Total dollar value of proposed assessments from MSHA under the Mine Act.

The table below sets forth the total number of citations and/or orders issued by MSHA to WRDC under the indicated provisions of the Mine Act, together with the total dollar value of proposed MSHA assessments received during the three months ended March 31, 2019 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for WRDC, our only mining complex. All citations were abated within 24 hours of issue.

Mine/ MSHA Identification Number	Mine Act Section 104 S&S Citations issued during three months ended March 31, 2019	Mine Act Section 104(b) Orders (#)	Mine Act Section 104(d) Citations and Orders (#)	Mine Act Section 110(b)(2) Violations (#)	Mine Act Section 107(a) Imminent Danger Orders (#)	Total Dollar Value of Proposed MSHA Assessments	Total Number of Mining Related Fatalities (#)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Pending as of Last Day of Period (#) (a)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
Wyodak Coal Mine - 4800083	—	—	—	—	—	$ 181	—	No	—	—	—

(a) The types of proceedings by class: (1) contests of citations and orders - none; (2) contests of proposed penalties - none; (3) complaints for compensation - none; (4) complaints of discharge, discrimination or interference under Section 105 of the Mine Act - none; (5) applications for temporary relief - none; and (6) appeals of judges' decisions or orders to the FMSHRC - none.