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

Form 10-Q

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

For the quarterly period ended September 30, 2019

OR

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

For the transition period from __________ to __________.

Commission File Number 001-31303

Black Hills Corporation

Incorporated in South Dakota IRS Identification Number 46-0458824

7001 Mount Rushmore Road Rapid City South Dakota 57702

Registrant’s telephone number (605) 721-1700

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

NONE

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

Yes 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	☐
Non-accelerated Filer	☐	Smaller Reporting Company	☐
		Emerging Growth Company	☐

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

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

Yes ☐ 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 October 31, 2019
Common stock, $1.00 par value	61,454,071 shares

TABLE OF CONTENTS

Table of Contents

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 and providing electric service)
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 and Wyoming Gas distribute the gas and Black Hills Energy Services, Wyoming Gas and Black Hills Gas Distribution are Choice Gas suppliers.
CIAC	Contribution In Aid of Construction
City of Gillette	Gillette, Wyoming
City of Cheyenne	Cheyenne, Wyoming
Chief Operating Decision Maker (CODM)	Chief Executive Officer
Colorado Electric	Black Hills Colorado Electric, LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado Gas	Black Hills Colorado Gas, Inc., 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 Revolving Credit Facility.
Cooling Degree Day (CDD)	A cooling degree day is equivalent to each degree that the average of the high and low temperatures 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
CT	Combustion turbine
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.
MW	Megawatts
MWh	Megawatt-hours
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
NPSC	Nebraska Public Service Commission
PPA	Power Purchase Agreement
Pueblo Airport Generation Station	Two 100 MW combined cycle gas-fired power generation plants owned by Colorado IPP and located at a site shared with Colorado Electric. The plants commenced operation on January 1, 2012.
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 and retired on August 17, 2018.
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
S&P	Standard and Poor’s, a division of The McGraw-Hill Companies, Inc.
South Dakota Electric	Black Hills Power, which includes 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.
Wind Capacity Factor	Measures the amount of electricity a wind turbine produces in a given time period relative to its maximum potential
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corporation, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Wyodak Plant	Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, owned 80% by PacifiCorp and 20% by Black Hills Energy South Dakota. Our WRDC mine supplies all of the fuel for the plant.
Wyoming Electric	Includes Cheyenne Light’s electric utility operations
Wyoming Gas	Black Hills Wyoming Gas, LLC, an indirect and wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands, except per share amounts)			
Revenue	$ 325,548	$ 321,979	$ 1,257,246	$ 1,253,072
Operating expenses:				
Fuel, purchased power and cost of natural gas sold	73,090	80,244	411,695	432,544
Operations and maintenance	117,037	115,699	366,907	352,092
Depreciation, depletion and amortization	51,884	49,046	154,507	146,345
Taxes - property and production	12,986	11,905	39,454	39,181
Total operating expenses	254,997	256,894	972,563	970,162
Operating income	70,551	65,085	284,683	282,910
Other income (expense):				
Interest charges -				
Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	(36,200)	(36,380)	(108,232)	(107,183)
Allowance for funds used during construction - borrowed	2,200	701	4,555	1,345
Interest income	513	382	1,208	1,012
Allowance for funds used during construction - equity	311	193	486	503
Impairment of investment	(19,741)	—	(19,741)	—
Other income (expense), net	269	(703)	(431)	(2,426)
Total other income (expense)	(52,648)	(35,807)	(122,155)	(106,749)
Income before income taxes	17,903	29,278	162,528	176,161
Income tax benefit (expense)	(2,508)	(7,477)	(22,078)	11,784
Income from continuing operations	15,395	21,801	140,450	187,945
Net (loss) from discontinued operations	—	(857)	—	(5,627)
Net income	15,395	20,944	140,450	182,318
Net income attributable to noncontrolling interest	(3,655)	(3,994)	(10,319)	(10,447)
Net income available for common stock	$ 11,740	$ 16,950	$ 130,131	$ 171,871
Amounts attributable to common shareholders:				
Net income from continuing operations	$ 11,740	$ 17,807	$ 130,131	$ 177,498
Net (loss) from discontinued operations	—	(857)	—	(5,627)
Net income available for common stock	$ 11,740	$ 16,950	$ 130,131	$ 171,871
Earnings (loss) per share of common stock, Basic -				
Earnings from continuing operations	$ 0.19	$ 0.33	$ 2.15	$ 3.33
(Loss) from discontinued operations	—	(0.02)	—	(0.10)
Total earnings per share of common stock, Basic	$ 0.19	$ 0.32	$ 2.15	$ 3.22
Earnings (loss) per share of common stock, Diluted -				
Earnings from continuing operations	$ 0.19	$ 0.32	$ 2.15	$ 3.26
(Loss) from discontinued operations	—	(0.02)	—	(0.10)
Total earnings per share of common stock, Diluted	$ 0.19	$ 0.31	$ 2.15	$ 3.15
Weighted average common shares outstanding:				
Basic	60,976	53,364	60,458	53,346
Diluted	61,104	54,819	60,578	54,508

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 September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in thousands)			
Net income	$ 15,395	$ 20,944	$ 140,450	$ 182,318
Other comprehensive income (loss), net of tax:				
Reclassification adjustments of benefit plan liability - prior service cost (net of tax of $3, $10, $13 and $29, respectively)	(16)	(34)	(45)	(104)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax of $(92), $(138), $(197), and $(409), respectively)	(9)	483	327	1,456
Derivative instruments designated as cash flow hedges:				
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(165), $(152), $(500), and $(456), respectively)	548	560	1,639	1,682
Net unrealized gains (losses) on commodity derivatives (net of tax of $35, $0, $100 and $51, respectively)	(115)	30	(334)	(168)
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $(5), $3, $142 and $(187), respectively)	124	21	(366)	615
Other comprehensive income, net of tax	532	1,060	1,221	3,481
Comprehensive income	15,927	22,004	141,671	185,799
Less: comprehensive income attributable to noncontrolling interest	(3,655)	(3,994)	(10,319)	(10,447)
Comprehensive income available for common stock	$ 12,272	$ 18,010	$ 131,352	$ 175,352

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	
	September 30, 2019	December 31, 2018
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13,087	$ 20,776
Restricted cash	3,688	3,369
Accounts receivable, net	148,989	269,153
Materials, supplies and fuel	123,002	117,299
Derivative assets, current	412	1,500
Income tax receivable, net	12,931	12,978
Regulatory assets, current	46,206	48,776
Other current assets	29,106	29,982
Total current assets	377,421	503,833
Investments	21,583	41,013
Property, plant and equipment	6,567,229	6,000,015
Less: accumulated depreciation and depletion	(1,243,794)	(1,145,136)
Total property, plant and equipment, net	5,323,435	4,854,879
Other assets:		
Goodwill	1,299,454	1,299,454
Intangible assets, net	13,566	14,337
Regulatory assets, non-current	214,152	235,459
Other assets, non-current	25,339	14,352
Total other assets, non-current	1,552,511	1,563,602
TOTAL ASSETS	$ 7,274,950	$ 6,963,327

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	
	September 30, 2019	December 31, 2018
	(in thousands, except share amounts)	
LIABILITIES AND TOTAL EQUITY		
Current liabilities:		
Accounts payable	$ 145,085	$ 210,609
Accrued liabilities	217,832	215,501
Derivative liabilities, current	2,396	947
Regulatory liabilities, current	25,168	29,810
Notes payable	294,900	185,620
Current maturities of long-term debt	5,743	5,743
Total current liabilities	691,124	648,230
Long-term debt	3,049,235	2,950,835
Deferred credits and other liabilities:		
Deferred income tax liabilities, net	347,952	311,331
Regulatory liabilities, non-current	498,773	510,984
Benefit plan liabilities	134,150	145,147
Other deferred credits and other liabilities	120,820	109,377
Total deferred credits and other liabilities	1,101,695	1,076,839
Commitments and contingencies (See Notes 8, 10, 15, 16)		
Equity:		
Stockholders' equity —		
Common stock $1 par value; 100,000,000 shares authorized; issued 61,480,640 and 60,048,567 shares, respectively	61,481	60,049
Additional paid-in capital	1,553,190	1,450,569
Retained earnings	742,138	700,396
Treasury stock, at cost – 26,572 and 44,253 shares, respectively	(1,636)	(2,510)
Accumulated other comprehensive income (loss)	(25,695)	(26,916)
Total stockholders' equity	2,329,478	2,181,588
Noncontrolling interest	103,418	105,835
Total equity	2,432,896	2,287,423
TOTAL LIABILITIES AND TOTAL EQUITY	$ 7,274,950	$ 6,963,327

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)	Nine Months Ended September 30, 2019	2018
Operating activities:	(in thousands)	
Net income	$ 140,450	$ 182,318
Loss from discontinued operations, net of tax	—	5,627
Income from continuing operations	140,450	187,945
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	154,507	146,345
Deferred financing cost amortization	6,326	5,682
Impairment of investment	19,741	—
Stock compensation	8,332	7,544
Deferred income taxes	24,381	(14,396)
Employee benefit plans	7,965	10,641
Other adjustments, net	9,192	7,668
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	(4,126)	(8,380)
Accounts receivable, unbilled revenues and other operating assets	115,325	72,061
Accounts payable and other operating liabilities	(83,436)	(86,604)
Regulatory assets - current	12,455	41,655
Regulatory liabilities - current	(15,644)	21,416
Contributions to defined benefit pension plans	(12,700)	(12,700)
Other operating activities, net	3,307	2,007
Net cash provided by operating activities of continuing operations	386,075	380,884
Net cash provided by (used in) operating activities of discontinued operations	—	(2,162)
Net cash provided by operating activities	386,075	378,722
Investing activities:		
Property, plant and equipment additions	(592,537)	(278,132)
Purchase of investment	—	(24,429)
Other investing activities	(735)	2,766
Net cash provided by (used in) investing activities of continuing operations	(593,272)	(299,795)
Net cash provided by investing activities of discontinued operations	—	18,024
Net cash provided by (used in) investing activities	(593,272)	(281,771)
Financing activities:		
Dividends paid on common stock	(91,779)	(76,309)
Common stock issued	101,361	1,079
Net (payments) borrowings of short-term debt	109,280	(99,200)
Long-term debt - issuances	400,000	700,000
Long-term debt - repayments	(304,307)	(603,307)
Distributions to noncontrolling interest	(12,736)	(13,755)
Other financing activities	(1,992)	(10,457)
Net cash provided by (used in) financing activities	199,827	(101,949)
Net change in cash, cash equivalents and restricted cash	(7,370)	(4,998)
Cash, cash equivalents and restricted cash at beginning of period	24,145	18,240
Cash, cash equivalents and restricted cash at end of period	$ 16,775	$ 13,242

See Note 14 for supplemental disclosure of cash flow information.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

(unaudited)	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 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)
Implementation of ASU 2016-02 Leases	—	—	—	—	—	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
Net income available for common stock	—	—	—	—	—	14,583	—	3,110	17,693
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	232	—	232
Dividends on common stock ($0.505 per share)	—	—	—	—	—	(30,620)	—	—	(30,620)
Share-based compensation	54,767	54	1,603	(112)	3,948	—	—	—	3,890
Issuance of common stock	658,598	659	—	—	49,342	—	—	—	50,001
Issuance costs	—	—	—	—	(492)	—	—	—	(492)
Implementation of ASU 2016-02 Leases	—	—	—	—	—	(3)	—	—	(3)
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(4,405)	(4,405)
June 30, 2019	61,091,385	$ 61,091	25,359	$ (1,544)	$ 1,522,208	$ 761,222	$ (26,227)	$ 103,248	$ 2,419,998
Net income (loss) available for common stock	—	—	—	—	—	11,740	—	3,655	15,395
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	532	—	532
Dividends on common stock ($0.505 per share)	—	—	—	—	—	(30,827)	—	—	(30,827)
Share-based compensation	18	—	1,213	(92)	1,769	—	—	—	1,677
Issuance of common stock	389,237	390	—	—	29,611	—	—	—	30,001
Issuance costs	—	—	—	—	(398)	—	—	—	(398)
Implementation of ASU 2016-02 Leases	—	—	—	—	—	3	—	—	3
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(3,485)	(3,485)
September 30, 2019	61,480,640	$ 61,481	26,572	$ (1,636)	$ 1,553,190	$ 742,138	$ (25,695)	$ 103,418	$ 2,432,896

(in thousands except share amounts)	Common Stock Shares	Common Stock Value	Treasury Stock Shares	Treasury Stock 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 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
Net income available for common stock	—	—	—	—	—	21,917	—	2,823	24,740
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	1,161	—	1,161
Dividends on common stock ($0.475 per share)	—	—	—	—	—	(25,435)	—	—	(25,435)
Share-based compensation	13,033	13	11,022	(593)	3,019	—	—	—	2,439
Other stock transactions	—	—	—	—	(5)	(1)	—	—	(6)
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(4,350)	(4,350)
June 30, 2018	53,661,850	$ 53,662	64,981	$ (3,642)	$ 1,154,947	$ 652,642	$ (38,763)	$ 107,687	$ 1,926,533
Net income (loss) available for common stock	—	—	—	—	—	16,950	—	3,994	20,944
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	1,060	—	1,060
Dividends on common stock ($0.475 per share)	—	—	—	—	—	(25,430)	—	—	(25,430)
Share-based compensation	13	—	7,934	(430)	2,107	—	—	—	1,677
Dividend reinvestment and stock purchase plan	—	—	—	—	1	—	—	—	1
Other stock transactions	—	—	—	—	159	(8)	—	—	151
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(3,757)	(3,757)
September 30, 2018	53,661,863	$ 53,662	72,915	$ (4,072)	$ 1,157,214	$ 644,154	$ (37,703)	$ 107,924	$ 1,921,179

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2018 Annual Report on Form 10-K)

(1) MANAGEMENT'S STATEMENT

The unaudited Condensed Consolidated Financial Statements included herein have been prepared by Black Hills Corporation (together with our subsidiaries the "Company", "us", "we" or "our"), pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations; however, we believe that the footnotes adequately disclose the information presented. These Condensed Consolidated Financial Statements should be read in conjunction with the consolidated financial statements and the notes thereto included in our 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.

Effective January 1, 2019, we changed our measure of segment performance to adjusted operating income, which impacted our segment disclosures for all periods presented. See Note 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 in 2018. The Oil and Gas segment assets and liabilities were classified as held for sale and the results of operations were 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 and Note 21 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 September 30, 2019 and December 31, 2018 financial information. 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 and nine months ended September 30, 2019 and September 30, 2018, and our financial condition as of September 30, 2019 and December 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.

Financial Instruments -- Credit Losses: Measurement of Credit Losses on Financial Instruments, ASU 2018-19

In June 2016, the FASB issued ASU 2016-13, Financial Instruments -- *Credit Losses: Measurement of Credit Losses on Financial Instrument*s, which was subsequently amended by ASU 2018-19 in November 2018. The standard introduces new accounting guidance for credit losses on financial instruments within its scope, including trade receivables. This new guidance adds an impairment model that is based on expected losses rather than incurred losses. It is effective for interim and annual reporting periods beginning after December 15, 2019, and will be applied on a modified-retrospective basis through a cumulative-effect adjustment to retained earnings as of January 1, 2020. We do not anticipate the adoption of this guidance to have a material 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 at January 1, 2019.

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 and nine months ended September 30, 2019 and 2018. Sales tax and other similar taxes are excluded from revenues.

Three Months Ended September 30, 2019	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer types:			(in thousands)			
Retail	$ 162,214	$ 89,810	$ —	$ 14,992	$ (8,146)	$ 258,870
Transportation	—	29,019	—	—	(195)	28,824
Wholesale	8,210	—	16,119	—	(14,414)	9,915
Market - off-system sales	6,452	139	—	—	(1,488)	5,103
Transmission/Other	14,274	10,965	—	—	(4,206)	21,033
Revenue from contracts with customers	$ 191,150	$ 129,933	$ 16,119	$ 14,992	$ (28,449)	$ 323,745
Other revenues	234	811	9,692	560	(9,494)	1,803
Total revenues	$ 191,384	$ 130,744	$ 25,811	$ 15,552	$ (37,943)	$ 325,548
Timing of revenue recognition:						
Services transferred at a point in time	$ —	$ —	$ —	$ 14,992	$ (8,146)	$ 6,846
Services transferred over time	191,150	129,933	16,119	—	(20,303)	316,899
Revenue from contracts with customers	$ 191,150	$ 129,933	$ 16,119	$ 14,992	$ (28,449)	$ 323,745

Three Months Ended September 30, 2018	Electric Utilities	Gas Utilities	Power Generation [(a)]	Mining	Inter-company Revenues [(a)]	Total
Customer Types:						
Retail	$ 157,049	$ 88,559	$ —	$ 16,751	$ (7,941)	$ 254,418
Transportation	—	30,079	—	—	(267)	29,812
Wholesale	8,255	—	15,373	—	(13,935)	9,693
Market - off-system sales	9,059	140	—	—	(1,349)	7,850
Transmission/Other	10,196	11,887	—	—	(3,693)	18,390
Revenue from contracts with customers	$ 184,559	$ 130,665	$ 15,373	$ 16,751	$ (27,185)	$ 320,163
Other revenues	231	1,011	9,118	550	(9,094)	1,816
Total Revenues	$ 184,790	$ 131,676	$ 24,491	$ 17,301	$ (36,279)	$ 321,979
Timing of Revenue Recognition:						
Services transferred at a point in time	$ —	$ —	$ —	$ 16,751	$ (7,942)	$ 8,809
Services transferred over time	184,559	130,665	15,373	—	(19,243)	311,354
Revenue from contracts with customers	$ 184,559	$ 130,665	$ 15,373	$ 16,751	$ (27,185)	$ 320,163

Nine Months Ended September 30, 2019	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer types:			(in thousands)			
Retail	$ 455,409	$ 567,715	$ —	$ 43,249	$ (23,315)	$ 1,043,058
Transportation	—	102,159	—	—	(903)	101,256
Wholesale	23,334	—	46,650	—	(40,923)	29,061
Market - off-system sales	16,592	517	—	—	(5,047)	12,062
Transmission/Other	42,865	35,767	—	—	(12,608)	66,024
Revenue from contracts with customers	$ 538,200	$ 706,158	$ 46,650	$ 43,249	$ (82,796)	$ 1,251,461
Other revenues	2,465	1,135	29,114	1,777	(28,706)	5,785
Total revenues	$ 540,665	$ 707,293	$ 75,764	$ 45,026	$ (111,502)	$ 1,257,246
Timing of revenue recognition:						
Services transferred at a point in time	$ —	$ —	$ —	$ 43,249	$ (23,315)	$ 19,934
Services transferred over time	538,200	706,158	46,650	—	(59,481)	1,231,527
Revenue from contracts with customers	$ 538,200	$ 706,158	$ 46,650	$ 43,249	$ (82,796)	$ 1,251,461

Nine Months Ended September 30, 2018	Electric Utilities	Gas Utilities	Power Generation (a)	Mining	Inter-company Revenues (a)	Total
Customer Types:						
Retail	$ 449,482	$ 565,816	$ —	$ 49,653	$ (23,761)	$ 1,041,190
Transportation	—	100,760	—	—	(977)	99,783
Wholesale	25,497	—	43,744	—	(39,457)	29,784
Market - off-system sales	18,142	728	—	—	(5,531)	13,339
Transmission/Other	36,622	36,230	—	—	(10,967)	61,885
Revenue from contracts with customers	$ 529,743	$ 703,534	$ 43,744	$ 49,653	$ (80,693)	$ 1,245,981
Other revenues	2,218	3,106	27,429	1,675	(27,337)	7,091
Total Revenues	$ 531,961	$ 706,640	$ 71,173	$ 51,328	$ (108,030)	$ 1,253,072
Timing of Revenue Recognition:						
Services transferred at a point in time	$ —	$ —	$ —	$ 49,653	$ (23,761)	$ 25,892
Services transferred over time	529,743	703,534	43,744	—	(56,932)	1,220,089
Revenue from contracts with customers	$ 529,743	$ 703,534	$ 43,744	$ 49,653	$ (80,693)	$ 1,245,981

(a) Due to the changes in our segment disclosures discussed in Note 3, Power Generation Wholesale revenue was revised for the three and nine months ended September 30, 2018, which resulted in an increase of $0.9 million and $2.6 million, respectively. The changes to Power Generation Wholesale revenue were offset by changes to eliminations in Inter-company Revenues within Corporate and Other and there was no impact to our consolidated Total Revenues.

Contract Balances

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

Accounting standards for presentation of segments require an approach based on the way we organize the segments for making operating decisions and how the chief operating decision maker (CODM) assesses performance. Effective January 1, 2019, we 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 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 performance.

Prior to January 1, 2019, operating income for the Electric Utilities and Power Generation segments and Corporate and Other included the impacts of finance lease accounting relating to Colorado Electric's PPA with Colorado IPP. This PPA provides 200 MW of energy and capacity to Colorado Electric from Colorado IPP's combined-cycle turbines and expires on December 31, 2031. Finance lease accounting required us to de-recognize the asset from Colorado IPP (Power Generation segment), which legally owns the asset, and recognize it at Colorado Electric (Electric Utilities segment).

The CODM assesses the performance of our segments using adjusted operating income, which recognizes intersegment revenues, costs, and assets for Colorado Electric's PPA with Colorado IPP on an accrual basis rather than as a finance lease. Effective January 1, 2019, we changed how we account for this PPA at the segment level, which impacts disclosures for all periods for revenues, fuel and purchased power cost, operating income and total assets for the Electric Utilities and Power Generation segments as well as Corporate and Other. There were no revisions to Gas Utilities and Mining segments and this change had no effect on our consolidated revenues, fuel and purchased power cost, operating income or total assets.

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

	External Operating Revenue		Inter-company Operating Revenue		
Three Months Ended September 30, 2019	Contract Customers	Other Revenues	Contract Customers	Other Revenues	Total Revenues
Segment:					
Electric Utilities	$ 185,811	$ 234	$ 5,339	$ —	$ 191,384
Gas Utilities	129,385	810	549	—	130,744
Power Generation	1,703	531	14,415	9,162	25,811
Mining	6,846	228	8,146	332	15,552
Inter-company eliminations	—	—	(28,449)	(9,494)	(37,943)
Total	$ 323,745	$ 1,803	$ —	$ —	$ 325,548

	External Operating Revenue		Inter-company Operating Revenue		
Three Months Ended September 30, 2018	Contract Customers	Other Revenues	Contract Customers	Other Revenues	Total Revenues
Segment:					
Electric Utilities	$ 179,527	$ 231	$ 5,032	$ —	$ 184,790
Gas Utilities	130,390	1,011	275	—	131,676
Power Generation [(a)]	1,437	348	13,936	8,770	24,491
Mining	8,809	226	7,942	324	17,301
Inter-company eliminations [(a)]	—	—	(27,185)	(9,094)	(36,279)
Total	$ 320,163	$ 1,816	$ —	$ —	$ 321,979

Nine Months Ended September 30, 2019	External Operating Revenue		Inter-company Operating Revenue		
	Contract Customers	Other Revenues	Contract Customers	Other Revenues	Total Revenues
Segment:					
Electric Utilities	$ 521,614	$ 2,465	$ 16,586	$ —	$ 540,665
Gas Utilities	704,188	1,134	1,971	—	707,293
Power Generation	5,725	1,401	40,924	27,714	75,764
Mining	19,934	785	23,315	992	45,026
Inter-company eliminations	—	—	(82,796)	(28,706)	(111,502)
Total	$ 1,251,461	$ 5,785	$ —	$ —	$ 1,257,246

Nine Months Ended September 30, 2018	External Operating Revenue		Inter-company Operating Revenue		
	Contract Customers	Other Revenues	Contract Customers	Other Revenues	Total Revenues
Segment:					
Electric Utilities	$ 513,270	$ 2,218	$ 16,473	$ —	$ 531,961
Gas Utilities	702,532	3,106	1,002	—	706,640
Power Generation [(a)]	4,287	1,066	39,457	26,363	71,173
Mining	25,892	701	23,761	974	51,328
Inter-company eliminations [(a)]	—	—	(80,693)	(27,337)	(108,030)
Total	$ 1,245,981	$ 7,091	$ —	$ —	$ 1,253,072

(a) Due to the changes in our segment disclosures, Power Generation Inter-company Operating Revenue for Contract Customers was revised for the three and nine months ended September 30, 2018 which resulted in an increase of $0.9 million and $2.6 million, respectively. The changes to Power Generation were offset by changes to Inter-company eliminations within Corporate and Other and there was no impact on our consolidated Total revenues.

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Adjusted operating income:				
Electric Utilities [(a)]	$ 50,653	$ 43,393	$ 125,219	$ 123,073
Gas Utilities	4,736	4,240	116,607	116,168
Power Generation [(a)]	11,822	13,079	33,945	33,731
Mining	3,374	4,551	9,351	12,647
Corporate and Other [(a)]	(34)	(178)	(439)	(2,709)
Operating income	70,551	65,085	284,683	282,910
Interest expense, net	(33,487)	(35,297)	(102,469)	(104,826)
Impairment of investment	(19,741)	—	(19,741)	—
Other income (expense), net	580	(510)	55	(1,923)
Income tax benefit (expense) [(b)]	(2,508)	(7,477)	(22,078)	11,784
Income from continuing operations	15,395	21,801	140,450	187,945
Net (loss) from discontinued operations	—	(857)	—	(5,627)
Net income	15,395	20,944	140,450	182,318
Net income attributable to noncontrolling interest	(3,655)	(3,994)	(10,319)	(10,447)
Net income available for common stock	$ 11,740	$ 16,950	$ 130,131	$ 171,871

(a) Due to the changes in our segment disclosures, Adjusted operating income was revised for the three and nine months ended September 30, 2018, which resulted in an increase (decrease) as follows (in millions):

Segment	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
Electric Utilities	$ 1.6	$ 4.8
Power Generation	(1.4)	(4.4)
Corporate and Other	(0.2)	(0.4)
	$ —	$ —

(b) Income tax benefit (expense) for the nine months ended September 30, 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:	September 30, 2019	December 31, 2018
Segment:		
Electric Utilities [(a)]	$ 2,810,108	$ 2,707,695
Gas Utilities	3,797,941	3,623,475
Power Generation [(a)]	414,526	342,085
Mining	78,073	80,594
Corporate and Other	174,302	209,478
Total assets	$ 7,274,950	$ 6,963,327

(a) Due to the changes in our segment disclosures, Electric Utilities and Power Generation Total assets were revised as of December 31, 2018 which resulted in an increase (decrease) of ($188) million and $188 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:

September 30, 2019	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 39,151	$ 31,843	$ (500)	$ 70,494
Gas Utilities	46,265	24,091	(2,490)	67,866
Power Generation	2,733	—	—	2,733
Mining	1,804	—	—	1,804
Corporate	6,261	—	(169)	6,092
Total	$ 96,214	$ 55,934	$ (3,159)	$ 148,989

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

Table of Contents

(5) REGULATORY ACCOUNTING

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

	September 30, 2019	December 31, 2018
Regulatory assets		
Deferred energy and fuel cost adjustments [a]	$ 31,832	$ 29,661
Deferred gas cost adjustments [a]	3,899	3,362
Gas price derivatives [a]	4,296	6,201
Deferred taxes on AFUDC [b]	7,691	7,841
Employee benefit plans [c]	107,921	110,524
Environmental [a]	917	959
Loss on reacquired debt [a]	19,710	21,001
Renewable energy standard adjustment [a]	2,871	1,722
Deferred taxes on flow through accounting [c]	37,609	31,044
Decommissioning costs [b]	11,206	11,700
Gas supply contract termination [a]	9,953	14,310
Other regulatory assets [a]	22,453	45,910
Total regulatory assets	260,358	284,235
Less current regulatory assets	(46,206)	(48,776)
Regulatory assets, non-current	$ 214,152	$ 235,459
Regulatory liabilities		
Deferred energy and gas costs [a]	$ 9,919	$ 6,991
Employee benefit plan costs and related deferred taxes [c]	42,737	42,533
Cost of removal [a]	162,169	150,123
Excess deferred income taxes [c]	286,587	310,562
TCJA revenue reserve	2,770	18,032
Other regulatory liabilities [c]	19,759	12,553
Total regulatory liabilities	523,941	540,794
Less current regulatory liabilities	(25,168)	(29,810)
Regulatory liabilities, non-current	$ 498,773	$ 510,984

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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

Wyoming Gas

On June 13, 2019, we received approval from the WPSC to consolidate our Wyoming gas utility operations into a new utility entity. The Wyoming portion of Black Hills Gas Distribution, LLC, Cheyenne Light's natural gas utility operations (Cheyenne Gas and Northeast Wyoming), and Wyoming Gas (Northwest Wyoming) were combined into a new company called Black Hills Wyoming Gas, LLC. On June 3, 2019, Wyoming Gas filed a rate review application with the WPSC to consolidate the rates, tariffs and services of its four existing gas distribution territories in Wyoming. The rate review requests $16 million in new revenue to recover investments in safety, reliability and system integrity. Wyoming Gas is also requesting a new rider mechanism to recover future safety and integrity investments in its system. A settlement was recently reached with the intervening parties in the rate review filing and filed with the WPSC on November 1, 2019. The stipulation and agreement are subject to review and approval by the WPSC, with a decision expected by the end of 2019.

South Dakota Electric and Wyoming Electric

South Dakota Electric and Wyoming Electric received approvals for the Renewable Ready Service Tariffs and related jointly-filed CPCN to construct the $57 million, 40 MW Corriedale Wind Energy Project. The wind project will be jointly owned by the two electric utilities to deliver renewable energy for large commercial, industrial and governmental agency customers. The project is expected to be in service by the end of 2020. In September 2019, the customer subscription period was completed with customer interest fulfilling the 40 MW of available energy. On November 1, 2019, South Dakota Electric filed with the SDPUC an amendment seeking approval to increase the generating capacity under the tariff for the South Dakota portion by 12.5 MW to a total of 32.5 MW.

Nebraska

On October 29, 2019, Nebraska Gas received approval from the NPSC to merge its two gas distribution companies in Nebraska. A rate review is expected to be filed by mid-year 2020 to consolidate the rates, tariffs and services of its two existing gas distribution companies.

Kansas

On June 25, 2019, Kansas Gas received approval from the Kansas Corporation Commission for an annual increase in revenue of $1.4 million, effective July 1, 2019, based on updates to the Gas System Reliability Surcharge Rider.

Wyoming Electric

On April 30, 2019, the WPSC approved Wyoming Electric's application for a new Blockchain Interruptible Service Tariff. The utility has partnered with the economic development organization for City of Cheyenne and Laramie County to actively recruit blockchain customers to the state. This tariff is complementary to recently enacted Wyoming legislation supporting the development of blockchain within the state.

Colorado

On February 1, 2019, Colorado Gas filed a rate review with the CPUC requesting approval to consolidate rates, tariffs, and services of its two existing gas distribution territories in Colorado. The rate review requests $2.5 million in new revenue to recover investments in safety, reliability and system integrity. Colorado Gas is also requesting a new rider mechanism to recover future safety and integrity investments in its system. A decision from the CPUC is expected by March 2020.

(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:

	September 30, 2019	December 31, 2018
Materials and supplies	$ 81,382	$ 75,081
Fuel - Electric Utilities	2,535	2,850
Natural gas in storage held for distribution	39,085	39,368
Total materials, supplies and fuel	$ 123,002	$ 117,299

(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 September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Net income available for common stock	$ 11,740	$ 16,950	$ 130,131	$ 171,871
Weighted average shares - basic	60,976	53,364	60,458	53,346
Dilutive effect of:				
Equity Units [a]	—	1,344	—	1,060
Equity compensation	128	111	120	102
Weighted average shares - diluted	61,104	54,819	60,578	54,508

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(a) Calculated using the treasury stock method. On November 1, 2018, we completed settlement of the stock purchase contracts that were 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 September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Equity compensation	2	12	4	15
Restricted Stock	—	—	1	—
Anti-dilutive shares	2	12	5	15

(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:

	September 30, 2019		December 31, 2018	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$ 50,000	$ 18,313	$ —	$ 22,311
CP Program	244,900	—	185,620	—
Total	$ 294,900	$ 18,313	$ 185,620	$ 22,311

Our $750 million corporate Revolving Credit Facility extends through July 30, 2023 with two, one year extension options (subject to consent from lenders). This facility includes an accordion feature that allows us, with the consent of the administrative agent, 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 September 30, 2019. Based on our credit ratings, a 0.175% commitment fee was charged on the unused amount at September 30, 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 short-term borrowings (payments) during the nine months ended September 30, 2019 were $109 million. At September 30, 2019, the weighted average interest rate on short-term borrowings was 2.43%.

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. As of September 30, 2019, we were in compliance with these covenants.

Debt Transaction

On June 17, 2019, we amended our Corporate term loan due July 30, 2020. This amendment increased total commitments to $400 million from $300 million, extended the term through June 17, 2021, and had substantially similar terms and covenants as the amended and restated Revolving Credit Facility. The net proceeds from the increase in total commitments were used to pay down short-term debt. Proceeds from the October 3, 2019 public debt offering were used to repay this term loan.

Subsequent Event - Debt Offering

On October 3, 2019, we completed a public debt offering of $700 million principal amount in senior unsecured notes. The debt offering consisted of $400 million of 3.05% 10-year senior notes due October 15, 2029 and $300 million of 3.875% 30-year senior notes due October 15, 2049 (together the “Notes”). The proceeds of the Notes were used for the following:

- Repay the $400 million Corporate term loan under the Amended and Restated Credit Agreement due June 17, 2021;
- Retire the $200 million 5.875% senior notes due July 15, 2020; and
- Repay a portion of short-term debt.

(9) EQUITY

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 September 30, 2019, we issued a total of 389,237 shares of common stock under the ATM equity offering program for proceeds of $30 million, net of $0.3 million in commissions. During the nine months ended September 30, 2019, we issued a total of 1,328,332 shares of common stock under the ATM equity offering program for proceeds of $99 million, net of $1.0 million in commissions. As of September 30, 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 guaranties, 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 October 2019 through October 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:

	September 30, 2019		December 31, 2018	
	Notional (MMBtus)	Maximum Term (months) (a)	Notional (MMBtus)	Maximum Term (months) (a)
Natural gas futures purchased	2,350,000	15	4,000,000	24
Natural gas options purchased, net	8,580,000	6	4,320,000	13
Natural gas basis swaps purchased	2,090,000	15	3,960,000	24
Natural gas over-the-counter swaps, net (b)	5,460,000	25	3,660,000	24
Natural gas physical contracts, net (c)	23,459,639	6	18,325,852	30

(a) Term reflects the maximum forward period hedged.
(b) As of September 30, 2019, 1,812,500 MMBtus were designated as cash flow hedges.
(c) Volumes exclude contracts that qualify for the normal purchase, normal sales exception.

Based on September 30, 2019 prices, a $0.4 million gain would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

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 September 30, 2019, the Company posted $0.5 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 and nine months ended September 30, 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 September 30, 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	(129)
Total		$ (842)

Three Months Ended September 30, 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	$ (712)
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(18)
Total		$ (730)

Nine Months Ended September 30, 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	$	(2,139)
Commodity derivatives	Fuel, purchased power and cost of natural gas sold		508
Total		$	(1,631)

Nine Months Ended September 30, 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	$	(2,138)
Commodity derivatives	Fuel, purchased power and cost of natural gas sold		(802)
Total		$	(2,940)

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 and nine months ended September 30, 2019 and 2018.

	Three Months Ended September 30,			
	2019		2018	
	(in thousands)			
Increase (decrease) in fair value:				
Forward commodity contracts	$	(150)	$	30
Recognition of (gains) losses in earnings due to settlements:				
Interest rate swaps		713		712
Forward commodity contracts		129		18
Total other comprehensive income (loss) from hedging	$	692	$	760

	Nine Months Ended September 30,			
	2019		2018	
	(in thousands)			
Increase (decrease) in fair value:				
Forward commodity contracts	$	(434)	$	(219)
Recognition of (gains) losses in earnings due to settlements:				
Interest rate swaps		2,139		2,138
Forward commodity contracts		(508)		802
Total other comprehensive income (loss) from hedging	$	1,197	$	2,721

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 and nine months ended September 30, 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 September 30,	
		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	$ (20)	$ (96)
Commodity derivatives	Other income (expense), net	142	—
		$ 122	$ (96)

		Nine Months Ended September 30,	
		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	$ (1,180)	$ 929
Commodity derivatives	Other income (expense), net	$ 142	$ —
		$ (1,038)	$ 929

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 asset or Regulatory liability accounts related to the hedges in our utilities were $4.3 million and $6.2 million as of September 30, 2019 and December 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 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.

Nonrecurring Fair Value Measurement

A discussion of the fair value of our investment in equity securities of a privately held oil and gas company, a Level 3 asset, is included in Note 21.

Recurring Fair Value Measurements

	As of September 30, 2019				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Utilities	$ —	$ 2,750	$ —	$ (2,335)	$ 415
Total	$ —	$ 2,750	$ —	$ (2,335)	$ 415
Liabilities:					
Commodity derivatives — Utilities	$ —	$ 6,080	$ —	$ (3,471)	$ 2,609
Total	$ —	$ 6,080	$ —	$ (3,471)	$ 2,609

	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

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	September 30, 2019	December 31, 2018
Derivatives designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets — current	$ —	$ 415
Noncurrent commodity derivatives	Other assets, non-current	2	18
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities — current	(427)	(114)
Noncurrent commodity derivatives	Other deferred credits and other liabilities	(70)	(4)
Total derivatives designated as hedges		$ (495)	$ 315
Derivatives not designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets — current	$ 412	$ 1,085
Noncurrent commodity derivatives	Other assets, non-current	1	1
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities — current	(1,969)	(833)
Noncurrent commodity derivatives	Other deferred credits and other liabilities	(143)	(56)
Total derivatives not designated as hedges		$ (1,699)	$ 197

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.

Table of Contents

(12) FAIR VALUE OF FINANCIAL INSTRUMENTS

Other financial instruments for which the carrying value did not equal fair value were as follows (in thousands) as of:

	September 30, 2019		December 31, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current maturities [(a)] [(b)]	$ 3,054,978	$ 3,424,747	$ 2,956,578	$ 3,039,108

(a) 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.
(b) 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 (in thousands):

		Amount Reclassified from AOCI			
		Three Months Ended		Nine Months Ended	
	Location on the Condensed Consolidated Statements of Income	September 30, 2019	September 30, 2018	September 30, 2019	September 30, 2018
Gains and (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$ (713)	$ (712)	$ (2,139)	$ (2,138)
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(129)	(18)	508	(802)
		(842)	(730)	(1,631)	(2,940)
Income tax	Income tax benefit (expense)	170	149	358	643
Total reclassification adjustments related to cash flow hedges, net of tax		$ (672)	$ (581)	$ (1,273)	$ (2,297)
Amortization of components of defined benefit plans:					
Prior service cost	Operations and maintenance	$ 20	$ 44	$ 59	$ 133
Actuarial gain (loss)	Operations and maintenance	(84)	(621)	(525)	(1,865)
		(64)	(577)	(466)	(1,732)
Income tax	Income tax benefit (expense)	89	128	184	380
Total reclassification adjustments related to defined benefit plans, net of tax		$ 25	$ (449)	$ (282)	$ (1,352)
Total reclassifications		$ (647)	$ (1,030)	$ (1,555)	$ (3,649)

Table of Contents

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	—	(334)	—	(334)
Amounts reclassified from AOCI	1,639	(366)	282	1,555
As of September 30, 2019	$ (15,668)	$ (372)	$ (9,655)	$ (25,695)

	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2017	$ (19,581)	$ (518)	$ (21,103)	$ (41,202)
Other comprehensive income (loss) before reclassifications	—	(168)	—	(168)
Amounts reclassified from AOCI	1,682	615	1,352	3,649
Reclassifications of certain tax effects from AOCI	15	—	3	18
As of September 30, 2018	$ (17,884)	$ (71)	$ (19,748)	$ (37,703)

(14) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Nine Months Ended	September 30, 2019	September 30, 2018
	(in thousands)	
Non-cash investing and financing activities —		
Property, plant and equipment acquired with accrued liabilities	$ 86,661	$ 49,631
Cash (paid) refunded during the period —		
Interest (net of amounts capitalized)	$ (99,375)	$ (104,035)
Income taxes	$ 2,255	$ (14,842)

(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 September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Service cost	$ 1,346	$ 1,708	$ 4,037	$ 5,125
Interest cost	4,344	3,867	13,031	11,602
Expected return on plan assets	(6,100)	(6,185)	(18,300)	(18,555)
Prior service cost	6	15	19	44
Net loss (gain)	941	2,158	2,822	6,473
Net periodic benefit cost	$ 537	$ 1,563	$ 1,609	$ 4,689

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 September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Service cost	$ 454	$ 573	$ 1,362	$ 1,718
Interest cost	560	521	1,683	1,563
Expected return on plan assets	(57)	(57)	(172)	(170)
Prior service cost (benefit)	(99)	(99)	(298)	(297)
Net loss (gain)	—	54	—	162
Net periodic benefit cost	$ 858	$ 992	$ 2,575	$ 2,976

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 September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Service cost	$ 429	$ 632	$ 2,406	$ 1,347
Interest cost	324	293	972	878
Prior service cost	—	—	1	1
Net loss (gain)	134	250	402	750
Net periodic benefit cost	$ 887	$ 1,175	$ 3,781	$ 2,976

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 September 30, 2019	Contributions Made Nine Months Ended September 30, 2019	Additional Contributions Anticipated for 2019	Contributions Anticipated for 2020
Defined Benefit Pension Plan	$ 12,700	$ 12,700	$ —	$ 12,700
Non-pension Defined Benefit Postretirement Healthcare Plans	$ 1,109	$ 3,326	$ 1,109	$ 4,815
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$ 366	$ 1,098	$ 366	$ 1,406

(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.

Future Purchase Agreement - Related Party

On August 2, 2019, Black Hills Wyoming and Wyoming Electric filed a request with FERC for approval of a new 60 MW PPA. If approved, Black Hills Wyoming will continue to deliver 60 MW of energy to Wyoming Electric from its Wygen I power plant starting January 1, 2023, and continuing for 20 additional years. A decision from FERC is pending.

Platte River Power Authority PPAs

- On June 26, 2019, Colorado Electric entered into a PPA with Platte River Power Authority to purchase up to 60 MW of wind energy upon construction completion of a new wind project, which is expected in mid-2020. This agreement will expire May 31, 2030.
- On June 26, 2019, Colorado Electric entered into a PPA with Platte River Power Authority to purchase 25 MW of unit contingent energy. This agreement was effective September 1, 2019 and will expire June 30, 2024.

The following is a schedule of unconditional purchase obligations required under the 25 MW Platte River Power Authority PPA as of September 30, 2019 (in thousands):

2019	$ 1,369
2020	$ 5,475
2021	$ 5,475
2022	$ 5,475
2023	$ 5,475
Thereafter	$ 2,738

(17) DISCONTINUED OPERATIONS

Results of operations for discontinued operations were classified as Loss from discontinued operations, net of income taxes in the accompanying Condensed Consolidated Statements of Income. Prior periods relating to our discontinued operations were also 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 in 2018. See Note 21 for more information.

(18) INCOME TAXES

Income tax benefit (expense) for the Three Months Ended September 30, 2019 Compared to the Three Months Ended September 30, 2018.

Income tax benefit (expense) for the three months ended September 30, 2019 was $(2.5) million compared to $(7.5) million reported for the same period in 2018. The decrease in tax expense was primarily due to a prior year $(5.3) million income tax expense associated with changes in the previously estimated impact of tax reform on deferred income taxes.

For the three months ended September 30, 2019 the effective tax rate was 14.0% compared to 7.6% excluding the tax reform adjustments, for the same period in 2018. The higher effective tax rate is primarily due to a prior year state tax benefit.

Income tax benefit (expense) for the Nine Months Ended September 30, 2019 Compared to the Nine Months Ended September 30, 2018.

Income tax benefit (expense) for the nine months ended September 30, 2019 was $(22) million compared to $12 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 $(7.5) million income tax expense associated with changes in the previously estimated impact of tax reform on deferred income taxes.

For the nine months ended September 30, 2019 the effective tax rate was 13.6% compared to 17.1% excluding the legal entity restructuring and tax reform adjustments, for the same period in 2018. The lower effective tax rate is primarily due to $5.0 million of federal production tax credits and related state investment tax credits associated with new wind assets and a $1.0 million tax benefit for deferred tax amortization related to tax reform.

(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:

	September 30, 2019	December 31, 2018
Accrued employee compensation, benefits and withholdings	$ 57,313	$ 63,742
Accrued property taxes	38,937	42,510
Customer deposits and prepayments	56,220	43,574
Accrued interest and contract adjustment payments	35,100	31,759
Other (none of which is individually significant)	30,262	33,916
Total accrued liabilities	$ 217,832	$ 215,501

(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 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 September 30, 2019	Nine Months Ended September 30, 2019
Operating lease cost	Operations and maintenance	$ 380	$ 1,076
Finance lease cost:			
Amortization of right-of-use asset	Depreciation, depletion and amortization	28	72
Interest on lease liabilities	Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	5	14
Total lease cost		$ 413	$ 1,162

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

	Balance Sheet Location	As of September 30, 2019
Assets:		
Operating lease assets	Other assets, non-current	$ 4,864
Finance lease assets	Other assets, non-current	493
Total lease assets		$ 5,357
Liabilities:		
Current:		
Operating leases	Accrued liabilities	$ 970
Finance lease	Accrued liabilities	80
Noncurrent:		
Operating leases	Other deferred credits and other liabilities	4,252
Finance lease	Other deferred credits and other liabilities	419
Total lease liabilities		$ 5,721

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

		Nine Months Ended September 30, 2019
Cash paid included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	895
Operating cash flows from finance lease	$	14
Financing cash flows from finance lease	$	66
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$	2,775
Finance lease	$	67

	As of September 30, 2019
Weighted average remaining lease term (years):	
Operating leases	8 years
Finance lease	4 years
Weighted average discount rate:	
Operating leases	4.27%
Finance lease	4.19%

As of September 30, 2019, scheduled maturities of lease liabilities for future years were as follows (in thousands):

		Operating Leases		Finance Lease		Total
2019 (a)	$	368	$	32	$	400
2020		992		126		1,118
2021		855		126		981
2022		736		126		862
2023		714		126		840
Thereafter		2,682		10		2,692
Total lease payments (b)	$	6,347	$	546	$	6,893
Less imputed interest		1,125		47		1,172
Present value of lease liabilities	$	5,222	$	499	$	5,721

(a) Includes lease liabilities for the remaining three 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 a 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 September 30, 2019	Nine Months Ended September 30, 2019
Operating lease income	Revenue	$ 544	$ 1,749

As of September 30, 2019, scheduled maturities of lease receivables for future years were as follows (in thousands):

	Operating Leases
2019 [a]	$ 551
2020	2,035
2021	1,857
2022	1,793
2023	1,799
Thereafter	55,481
Total lease receivables	$ 63,516

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

(21) INVESTMENTS

In February 2018, we made a contribution of $28 million of assets in exchange for equity securities in a privately held oil and gas company as we divested from our Oil and Gas segment. The carrying value of our investment in the equity securities was recorded at cost. We review this investment on a periodic basis to determine whether a significant event or change in circumstances has occurred that may have an adverse effect on the value of the investment.

During the third quarter of 2019, we assessed our investment for impairment as a result of a deterioration in earnings performance of the privately held oil and gas company and an adverse change in future natural gas prices. We engaged a third-party valuation consultant to estimate the fair value of our investment. The valuation was primarily based on an income approach but also considered a market valuation approach. The significant inputs used to estimate the fair value were the oil and gas reserve quantities and values utilizing forward market price curves, industry standard reserve adjustment factors and a discount rate of 10%. Based on the results of the valuation, we concluded that the carrying value of the investment exceeded fair value. As a result, we recorded a pre-tax impairment loss of $20 million for the three and nine months ended September 30, 2019, which was the difference between the carrying amount and the fair value of the investment.

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

	September 30, 2019	December 31, 2018
Investment in privately held oil and gas company	$ 8,359	$ 28,100
Cash surrender value of life insurance contracts	12,907	12,812
Other investments	317	101
Total investments	$ 21,583	$ 41,013

(22) SUBSEQUENT EVENTS

There are no subsequent events, other than those disclosed in Note 8.

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 regulator-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 extracts 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.

Effective January 1, 2019, we changed our measure of segment performance to adjusted operating income, which impacted our segment disclosures for all periods presented. See Note 3 of the Notes to Condensed Consolidated Financial Statements for more information.

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 and nine months ended September 30, 2019 and 2018, and our financial condition as of September 30, 2019 and December 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 58.

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 September 30,				Nine Months Ended September 30,			
	2019		2018		2019		2018	
(in millions, except per share amounts)	Income	EPS	Income	EPS	Income	EPS	Income	EPS
Net income from continuing operations available for common stock	$ 11.7	$ 0.19	$ 17.8	$ 0.32	$ 130.1	$ 2.15	$ 177.5	$ 3.26
Net (loss) from discontinued operations	—	—	(0.9)	(0.02)	—	—	(5.6)	(0.10)
Net income available for common stock	$ 11.7	$ 0.19	$ 17.0	$ 0.31	$ 130.1	$ 2.15	$ 171.9	$ 3.15

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018.

The variance to the prior year included the following:

- Electric Utilities' adjusted operating income increased $7.3 million primarily due to the prior year Wyoming Electric PCA settlement, warmer summer weather in Colorado and Wyoming, increased industrial demand, and increased rider revenues partially offset by higher operating expenses driven by outside services and employee costs;
- Gas Utilities' adjusted operating income increased $0.5 million primarily due to new rates, increased transport and transmission, and customer growth partially offset by lower heating demand from warmer weather, reduced irrigation demand due to heavy precipitation and higher operating expenses driven by outside services and employee costs;
- Power Generation's adjusted operating income decreased $1.3 million primarily due to higher depreciation and property taxes from new wind assets partially offset by higher revenue from increased wind MWh sold and higher PPA prices;
- Mining's adjusted operating income decreased $1.2 million primarily due to lower tons sold driven by unplanned generating facility outages partially offset by lower operating expenses;
- A $20 million non-cash impairment of our investment in equity securities of a privately held oil and gas company; and
- A prior year $5.3 million income tax expense associated with changes in the previously estimated impact of tax reform on deferred income taxes.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018.

The variance to the prior year included the following:

- Electric Utilities' adjusted operating income increased $2.1 million primarily due to reduced power capacity charges, the prior year Wyoming Electric PCA settlement and increased rider revenues partially offset by higher operating expenses driven by outside services and employee costs;
- Gas Utilities' adjusted operating income increased $0.4 million primarily due to new rates offset by higher operating expenses driven by outside services and employee costs;
- Power Generation's adjusted operating income increased $0.2 million primarily due to higher revenue from increased wind MWh sold partially offset by higher depreciation and property taxes from new wind assets;
- Mining's adjusted operating income decreased $3.3 million primarily due to lower tons sold driven by planned and unplanned generating facility outages partially offset by lower operating expenses;
- Corporate and Other expenses decreased $2.3 million primarily due to prior year expenses related to the oil and gas segment that were not reclassified to discontinued operations;
- A $20 million non-cash impairment of our investment in equity securities of a privately held oil and gas company;
- A prior year $49 million tax benefit resulting from legal entity restructuring partially offset by a prior year $7.5 million income tax expense associated with changes in the previously estimated impact of tax reform on deferred income taxes; and
- A lower current year effective tax rate primarily due to $5.0 million of federal production tax credits and related state investment tax credits associated with new wind assets and a $1.0 million tax benefit for deferred tax amortization related to tax reform.

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

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Three Months Variance	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018	Nine Months Variance
Revenue						
Revenue	$ 363,491	$ 358,258	$ 5,233	$ 1,368,748	$ 1,361,102	$ 7,646
Inter-company eliminations	(37,943)	(36,279)	(1,664)	(111,502)	(108,030)	(3,472)
	$ 325,548	$ 321,979	$ 3,569	$ 1,257,246	$ 1,253,072	$ 4,174
Adjusted operating income [(a)]						
Electric Utilities	$ 50,653	$ 43,393	$ 7,260	$ 125,219	$ 123,073	$ 2,146
Gas Utilities	4,736	4,240	496	116,607	116,168	439
Power Generation	11,822	13,079	(1,257)	33,945	33,731	214
Mining	3,374	4,551	(1,177)	9,351	12,647	(3,296)
Corporate and Other	(34)	(178)	144	(439)	(2,709)	2,270
Operating income	70,551	65,085	5,466	284,683	282,910	1,773
Interest expense, net	(33,487)	(35,297)	1,810	(102,469)	(104,826)	2,357
Impairment of investment	(19,741)	—	(19,741)	(19,741)	—	(19,741)
Other income (expense), net	580	(510)	1,090	55	(1,923)	1,978
Income tax benefit (expense)	(2,508)	(7,477)	4,969	(22,078)	11,784	(33,862)
Income from continuing operations	15,395	21,801	(6,406)	140,450	187,945	(47,495)
Net (loss) from discontinued operations	—	(857)	857	—	(5,627)	5,627
Net income	15,395	20,944	(5,549)	140,450	182,318	(41,868)
Net income attributable to noncontrolling interest	(3,655)	(3,994)	339	(10,319)	(10,447)	128
Net income available for common stock	$ 11,740	$ 16,950	$ (5,210)	$ 130,131	$ 171,871	$ (41,740)

(a) In 2019, we changed our measure of segment performance to adjusted operating income, which impacted our segment disclosures for all periods presented. See Note 3 of the Notes to Condensed Consolidated Financial Statements for additional information.

Overview of Business Segments and Corporate Activity

Electric Utilities Segment

- Cooling degree days for the three and nine months ended September 30, 2019 were 27% and 14% higher than normal compared to 9% and 29% higher than normal for the same periods in 2018.

  Heating degree days for the three and nine months ended September 30, 2019 were 36% lower and 6% higher than normal, compared to 20% and 3% lower than normal for the same periods in 2018.

- On September 17, 2019, South Dakota Electric completed construction on the final 94-mile segment of a 175-mile electric transmission line from Rapid City, South Dakota, to Stegall, Nebraska. The first 48-mile segment was placed in service on July 25, 2018, and the second 33-mile segment was placed in service on November 20, 2018.

- Colorado Electric and Wyoming Electric set new all-time and summer peak loads:

  - On July 19, 2019, Colorado Electric set a new peak load of 422 MW, exceeding the previous peak of 413 MW set in June 2018.

  - On July 19, 2019, Wyoming Electric set a new peak load of 265 MW, exceeding the previous peak of 254 MW set in July 2018.

- South Dakota Electric and Wyoming Electric received approvals for the Renewable Ready Service Tariffs and related jointly-filed CPCN to construct the $57 million, 40 MW Corriedale Wind Energy Project. The wind project will be jointly owned by the two electric utilities to deliver renewable energy for large commercial, industrial and governmental agency customers. The project is expected to be in service by the end of 2020. In September 2019, the customer subscription period was completed with customer interest fulfilling the 40 MW of available energy. On November 1, 2019, South Dakota Electric filed with the SDPUC an amendment seeking approval to increase the generating capacity under the tariff for the South Dakota portion by 12.5 MW to a total of 32.5 MW.

Gas Utilities Segment

- Heating degree days for the three and nine months ended September 30, 2019 were 62% lower and 7% higher than normal, compared to 27% lower and 0% higher than normal for the same periods in 2018.

- Regulatory activity:

    - On October 29, 2019, Nebraska Gas received approval from the NPSC to merge its two gas distribution companies in Nebraska. A rate review is expected to be filed by mid-year 2020 to consolidate the rates, tariffs and services of its two existing gas distribution companies.

    - On June 3, 2019, Wyoming Gas filed a rate review application with the WSPC to consolidate the rates, tariffs and services of its four existing gas distribution territories in Wyoming. The rate review requests $16 million in new revenue to recover investments in safety, reliability and system integrity. Wyoming Gas is also requesting a new rider mechanism to recover future safety and integrity investments in its system. A settlement was recently reached with the intervening parties in the rate review filing and filed with the WPSC on November 1, 2019. The stipulation and agreement are subject to review and approval by the WPSC, with a decision expected by the end of 2019. See Note 5 of the Notes to Condensed Consolidated Financial Statements for additional details.

    - On February 1, 2019, Colorado Gas filed a rate review with the CPUC requesting approval to consolidate rates, tariffs and services of its two existing gas distribution territories in Colorado. The rate review requests $2.5 million in new revenue to recover investments in safety, reliability and system integrity. Colorado Gas is also requesting a new rider mechanism to recover future safety and integrity investments in its system. A decision from the CPUC is expected by March 2020.

- On May 10, 2019, Wyoming Gas commenced construction on the $54 million, 35-mile Natural Bridge pipeline project to enhance supply reliability and delivery capacity for customers in central Wyoming. The new 12-inch steel pipeline will interconnect from a supply point near Douglas, Wyoming, to existing facilities near Casper, Wyoming. Construction of the pipeline is nearly complete and the project is expected to be in service by the end of 2019, with the associated investment included in the Wyoming Gas rate review filed on June 3, 2019.

Power Generation Segment

- On August 2, 2019 Black Hills Wyoming and Wyoming Electric jointly filed a request with FERC for approval of a new 60 MW PPA. If approved, Black Hills Wyoming will continue to deliver 60 MW of energy to Wyoming Electric from its Wygen I power plant starting January 1, 2023, and for 20 additional years. A decision from FERC is pending.

- On March 11, 2019, Black Hills Electric Generation commenced construction on the $71 million, 60 MW Busch Ranch II Wind Farm. The project is expected to be fully in service by mid-November 2019.

Mining

- In October, negotiations were completed for the price reopener in the contract with Wyodak Plant. The new price was reset at $17.94 per ton effective July 1, 2019, compared to the prior contract price of $18.25 per ton.

Corporate and Other

- On October 15, 2019, Moody’s affirmed South Dakota Electric’s credit rating at A1.

- On October 3, 2019, we completed a public debt offering of $700 million in senior unsecured notes. Proceeds were used to repay the $400 million Corporate term loan due June 17, 2021, retire the $200 million 5.875% senior notes due July 15, 2020 and repay a portion of short-term debt.

- During the nine months ended September 30, 2019, we issued a total of 1,328,332 shares of common stock under the ATM equity offering program for net proceeds of $99 million.

- On August 29, 2019, Fitch affirmed our BBB+ rating and maintained a Stable outlook.

- On June 17, 2019, we amended our Corporate term loan due July 30, 2020. This amendment increased total commitments to $400 million from $300 million and extended the term through June 17, 2021 on substantially similar terms and covenants. The net proceeds were used to pay down short-term debt. Proceeds from the October 3, 2019 debt transaction were used to repay this term loan.

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

- 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.

Table of Contents

Electric Utilities

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2019	2018	Variance	2019	2018	Variance
	(in thousands)					
Revenue	$ 191,384	$ 184,790	$ 6,594	$ 540,665	$ 531,961	$ 8,704
Total fuel and purchased power	71,593	74,638	(3,045)	207,004	209,317	(2,313)
Gross margin (non-GAAP)	119,791	110,152	9,639	333,661	322,644	11,017
Operations and maintenance	47,172	45,307	1,865	143,049	135,501	7,548
Depreciation and amortization	21,966	21,453	513	65,393	64,070	1,323
Total operating expenses	69,138	66,760	2,378	208,442	199,571	8,871
Adjusted operating income [(a)]	$ 50,653	$ 43,392	$ 7,261	$ 125,219	$ 123,073	$ 2,146

(a) Due to the changes in our segment disclosures discussed in Note 3 of the Notes to Condensed Consolidated Financial Statements, Electric Utilities' Adjusted operating income was revised for the three and nine months ended September 30, 2018, which resulted in an increase of $1.6 million and $4.8 million, respectively.

Results of Operations for the Electric Utilities for the Three Months Ended September 30, 2019 Compared to the Three Months Ended September 30, 2018:

Gross margin for the three months ended September 30, 2019 increased as a result of the following:

	(in millions)
Prior year Wyoming Electric PCA Stipulation settlement	$ 3.4
Weather	1.8
Increased industrial demand	1.7
Reduction in power capacity charges	1.7
Rider recovery	1.3
Other	(0.3)
Total increase in Gross margin (non-GAAP)	$ 9.6

Operations and maintenance expense increased primarily due to $1.0 million of higher employee costs and $0.6 million of higher outside services expenses.

Results of Operations for the Electric Utilities for the Nine Months Ended September 30, 2019 Compared to the Nine Months Ended September 30, 2018:

Gross margin for the nine months ended September 30, 2019 increased as a result of the following:

	(in millions)
Reduction in power capacity charges	$ 4.9
Prior year Wyoming Electric PCA Stipulation settlement	3.7
Rider recovery	2.0
Decreased residential customer usage	(0.9)
Decreased commercial and industrial demand	(0.2)
Weather	(0.1)
Other	1.6
Total increase in Gross margin (non-GAAP)	$ 11.0

Operations and maintenance expense increased primarily due to $3.6 million of higher employee costs and $3.4 million of higher outside services expenses.

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

Operating Statistics

	Electric Revenue (in thousands)				Quantities sold (MWh)			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018	2019	2018	2019	2018
Residential	$ 58,919	$ 58,122	$ 162,257	$ 163,979	384,735	372,623	1,075,394	1,084,531
Commercial	65,732	65,794	186,434	192,680	560,547	550,791	1,556,449	1,560,911
Industrial	33,937	31,939	98,074	93,959	462,809	429,133	1,335,260	1,248,438
Municipal	4,792	4,582	13,184	13,389	46,106	43,972	121,025	122,953
Subtotal Retail Revenue - Electric	163,380	160,437	459,949	464,007	1,454,197	1,396,519	4,088,128	4,016,833
Contract Wholesale	8,211	8,256	23,335	25,497	229,369	221,327	646,611	677,163
Off-system/Power Marketing Wholesale	6,452	9,059	16,592	18,142	160,357	206,791	436,298	514,686
Other	13,341	7,038	40,789	24,315	—	—	—	—
Total Revenue and Energy Sold	191,384	184,790	540,665	531,961	1,843,923	1,824,637	5,171,037	5,208,682
Other Uses, Losses or Generation, net	—	—	—	—	112,172	121,478	299,038	337,939
Total Revenue and Energy	191,384	184,790	540,665	531,961	1,956,095	1,946,115	5,470,075	5,546,621
Less cost of fuel and purchased power [(a)]	71,593	74,638	207,004	209,317				
Gross Margin (non-GAAP) [(a)]	$ 119,791	$ 110,152	$ 333,661	$ 322,644				

(a) Due to the changes in our segment disclosures discussed in Note 3 of the Notes to Condensed Consolidated Financial Statements, cost of fuel and purchased power was revised for the three and nine months ended September 30, 2018, which resulted in an increase of $1.6 million and $4.8 million, respectively. There were corresponding decreases to Gross margin for each period.

Three Months Ended September 30,	Electric Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Quantities Sold (MWh) [(a)]	
	2019	2018	2019	2018	2019	2018
Colorado Electric [(b)]	$ 70,771	$ 68,052	$ 41,916	$ 38,449	634,098	610,079
South Dakota Electric	77,022	78,067	55,217	52,860	835,725	874,962
Wyoming Electric	43,591	38,671	22,658	18,843	486,272	461,074
Total Electric Revenue, Gross Margin (non-GAAP), and Quantities Sold	$ 191,384	$ 184,790	$ 119,791	$ 110,152	1,956,095	1,946,115

Nine Months Ended September 30,	Electric Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Quantities Sold (MWh) [(a)]	
	2019	2018	2019	2018	2019	2018
Colorado Electric [(b)]	$ 186,030	$ 188,937	$ 104,411	$ 105,997	1,611,126	1,639,607
South Dakota Electric	225,309	222,558	162,390	154,158	2,438,366	2,541,082
Wyoming Electric	129,326	120,466	66,860	62,489	1,420,583	1,365,932
Total Electric Revenue, Gross Margin (non-GAAP), and Quantities Sold	$ 540,665	$ 531,961	$ 333,661	$ 322,644	5,470,075	5,546,621

(a) Total MWh for 2019 includes Other Uses, Losses or Generation, net, which are approximately 6%, 5%, and 6% for Colorado Electric, South Dakota Electric, and Wyoming Electric, respectively.

(b) Due to the changes in our segment disclosures discussed in Note 3 of the Notes to Condensed Consolidated Financial Statements, Gross margin was revised for the three and nine months ended September 30, 2018, which resulted in a decrease of $(1.6) million and $(4.8) million, respectively.

Quantities Generated and Purchased (MWh)	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Coal-fired	564,220	608,417	1,621,355	1,772,750
Natural Gas and Oil	234,366	199,351	445,498	345,978
Wind	55,407	54,450	167,331	196,932
Total Generated	853,993	862,218	2,234,184	2,315,660
Purchased	1,102,102	1,083,897	3,235,891	3,230,961
Total Generated and Purchased	1,956,095	1,946,115	5,470,075	5,546,621

Quantities Generated and Purchased (MWh)	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Generated:				
Colorado Electric	149,509	163,276	341,925	388,251
South Dakota Electric	489,042	469,680	1,262,336	1,293,713
Wyoming Electric	215,442	229,262	629,923	633,696
Total Generated	853,993	862,218	2,234,184	2,315,660
Purchased:				
Colorado Electric	484,589	446,803	1,269,201	1,251,356
South Dakota Electric	346,683	405,282	1,176,030	1,247,369
Wyoming Electric	270,830	231,812	790,660	732,236
Total Purchased	1,102,102	1,083,897	3,235,891	3,230,961
Total Generated and Purchased	1,956,095	1,946,115	5,470,075	5,546,621

Degree Days	Three Months Ended September 30, 2019			2018	
	Actual	Variance from Normal	Actual Variance to Prior Year	Actual	Variance from Normal
Heating Degree Days:					
Colorado Electric	4	(96)%	(89)%	35	(64)%
South Dakota Electric	175	(22)%	(26)%	236	5 %
Wyoming Electric	120	(77)%	(52)%	248	(19)%
Combined [(a)]	86	(36)%	(41)%	147	(20)%
Cooling Degree Days:					
Colorado Electric	1,079	58 %	19%	910	33 %
South Dakota Electric	366	(31)%	3%	356	(33)%
Wyoming Electric	433	45 %	32%	328	10 %
Combined [(a)]	705	27 %	17%	603	9 %

	Nine Months Ended September 30, 2019			2018	
Heating Degree Days	Actual	Variance from Normal	Actual Variance to Prior Year	Actual	Variance from Normal
Colorado Electric	3,156	(6)%	9%	2,901	(14)%
South Dakota Electric	5,370	20 %	8%	4,972	11 %
Wyoming Electric	4,677	5 %	9%	4,285	(9)%
Combined [(a)]	4,198	6 %	8%	3,888	(3)%
Cooling Degree Days:					
Colorado Electric	1,226	37 %	(13)%	1,404	57 %
South Dakota Electric	404	(36)%	(17)%	488	(23)%
Wyoming Electric	462	33 %	7%	430	24 %
Combined [(a)]	791	14 %	(12)%	895	29 %

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

Electric Utilities Power Plant Availability	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Coal-fired plants [(a)]	94.6%	95.7%	90.0%	94.0%
Natural gas-fired plants and Other plants [(b)]	89.6%	97.0%	89.8%	97.2%
Wind	93.7%	96.9%	95.0%	96.9%
Total availability	91.5%	96.6%	90.3%	96.1%
Wind capacity factor	33.8%	33.1%	37.1%	41.8%

(a) 2019 included planned outages at Neil Simpson II and Wygen III and unplanned outages at Wyodak Plant and Wygen III.
(b) 2019 included planned outages at Neil Simpson CT and Lange CT.

Gas Utilities

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2019	2018	Variance	2019	2018	Variance
			(in thousands)			
Revenue:						
Natural gas - regulated	$ 117,549	$ 117,070	$ 479	$ 651,366	$ 648,550	$ 2,816
Other - non-regulated services	13,195	14,606	(1,411)	55,927	58,090	(2,163)
Total revenue	130,744	131,676	(932)	707,293	706,640	653
Cost of sales:						
Natural gas - regulated	28,154	30,612	(2,458)	280,312	298,149	(17,837)
Other - non-regulated services	4,870	5,514	(644)	16,975	15,716	1,259
Total cost of sales	33,024	36,126	(3,102)	297,287	313,865	(16,578)
Gross margin (non-GAAP)	97,720	95,550	2,170	410,006	392,775	17,231
Operations and maintenance	70,170	69,746	424	225,239	212,319	12,920
Depreciation and amortization	22,814	21,564	1,250	68,160	64,288	3,872
Total operating expenses	92,984	91,310	1,674	293,399	276,607	16,792
Adjusted operating income	$ 4,736	$ 4,240	$ 496	$ 116,607	$ 116,168	$ 439

Results of Operations for the Gas Utilities for the Three Months Ended September 30, 2019 Compared to the Three Months Ended September 30, 2018:

Gross margin for the three months ended September 30, 2019 increased as a result of:

	(in millions)
New rates	$ 3.0
Customer growth - distribution	0.8
Increased transport and transmission	0.7
Weather [(a)]	(3.4)
Other	1.1
Total increase in Gross margin (non-GAAP)	$ 2.2

(a) Weather impacts for the three months ended September 30, 2019 compared to the same period in the prior year include reduced heating demand due to warmer temperatures and reduced irrigation loads to agriculture customers in our Nebraska Gas service territory due to higher precipitation.

Operations and maintenance expense increased primarily due to higher employee costs and higher outside services expenses.

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

Results of Operations for the Gas Utilities for the Nine Months Ended September 30, 2019 Compared to the Nine Months Ended September 30, 2018:

Gross margin for the nine months ended September 30, 2019 increased as a result of:

		(in millions)
New rates	$	15.5
Customer growth - distribution		3.7
Increased transport and transmission		1.8
Decreased mark-to-market on non-utility natural gas commodity contracts		(2.7)
Excess deferred taxes returned to customers		(2.5)
Weather		(0.6)
Other		2.0
Total increase in Gross margin (non-GAAP)	$	17.2

Operations and maintenance expense increased primarily due to $7.2 million of higher outside services expenses, $4.1 million of higher employee costs and $1.3 million of higher property taxes due to a higher asset base driven by prior and current year capital expenditures.

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

Operating Statistics

	Gas Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Gas Utilities Quantities Sold & Transported (Dth)	
	Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018	2019	2018
Residential	$ 57,244	$ 58,221	$ 43,441	$ 42,598	3,599,549	3,708,196
Commercial	19,629	19,639	11,589	10,880	2,298,919	2,278,304
Industrial	8,770	8,258	2,493	2,028	2,960,930	2,304,098
Other [(a)]	2,499	487	2,499	487	—	—
Total Distribution	88,142	86,605	60,022	55,993	8,859,398	8,290,598
Transportation and Transmission	29,407	30,465	29,373	30,465	31,538,815	29,808,567
Total Regulated	117,549	117,070	89,395	86,458	40,398,213	38,099,165
Non-regulated Services	13,195	14,606	8,325	9,092		
Total Gas Revenue & Gross Margin (non-GAAP)	$ 130,744	$ 131,676	$ 97,720	$ 95,550		

	Gas Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Gas Utilities Quantities Sold & Transported (Dth)	
	Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018	2019	2018
Residential	$ 383,466	$ 383,972	$ 201,168	$ 192,072	44,356,725	42,642,021
Commercial	146,752	148,675	61,673	57,890	21,484,646	20,842,996
Industrial	18,764	20,805	5,830	5,341	5,141,399	5,235,417
Other [(a)]	(968)	(6,789)	(968)	(6,789)	—	—
Total Distribution	548,014	546,663	267,703	248,514	70,982,770	68,720,434
Transportation and Transmission	103,352	101,887	103,351	101,887	110,622,285	107,388,321
Total Regulated	651,366	648,550	371,054	350,401	181,605,055	176,108,755
Non-regulated Services	55,927	58,090	38,952	42,374		
Total Gas Revenue & Gross Margin	$ 707,293	$ 706,640	$ 410,006	$ 392,775		

(a) Other revenue reflects the impact of revenue reserved in accordance with the TCJA.

	Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Gas Utilities Quantities Sold & Transported (Dth)	
	Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018	2019	2018
Arkansas	$ 21,387	$ 18,743	$ 16,249	$ 13,415	4,094,454	4,022,089
Colorado	22,632	22,362	15,667	15,210	3,806,360	2,893,029
Iowa	16,381	16,982	13,135	12,556	5,686,772	5,595,205
Kansas	19,013	18,497	12,309	11,129	7,602,758	6,164,821
Nebraska	35,715	40,553	28,046	31,264	13,999,302	13,831,306
Wyoming	15,616	14,539	12,314	11,976	5,208,567	5,592,715
Total Gas Revenue & Gross Margin (non-GAAP)	$ 130,744	$ 131,676	$ 97,720	$ 95,550	40,398,213	38,099,165

	Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Gas Utilities Quantities Sold & Transported (Dth)	
	Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018	2019	2018
Arkansas	$ 127,014	$ 116,226	$ 79,148	$ 65,803	21,061,567	21,183,322
Colorado	135,816	125,898	73,022	66,917	23,050,638	19,301,834
Iowa	105,736	111,968	50,773	49,630	28,834,731	28,527,522
Kansas	77,609	81,880	42,385	40,896	24,336,744	23,391,905
Nebraska	183,827	196,307	111,828	117,925	57,815,316	58,223,856
Wyoming	77,291	74,361	52,850	51,604	26,506,059	25,480,316
Total Gas Revenue & Gross Margin (non-GAAP)	$ 707,293	$ 706,640	$ 410,006	$ 392,775	181,605,055	176,108,755

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 September 30,				
	2019			2018	
Heating Degree Days	Actual	Variance from Normal	Actual Variance to Prior Year	Actual	Variance from Normal
Arkansas [a]	—	(100)%	(100)%	12	(72)%
Colorado	68	(68)%	(38)%	109	(49)%
Iowa	43	(69)%	(66)%	128	(7)%
Kansas [a]	—	(101)%	(100)%	54	(2)%
Nebraska	22	(80)%	(78)%	101	(7)%
Wyoming	183	(37)%	(22)%	236	(23)%
Combined [b]	53	(62)%	(51)%	109	(27)%

	Nine Months Ended September 30,				
	2019			2018	
Heating Degree Days:	Actual	Variance from Normal	Actual Variance to Prior Year	Actual	Variance from Normal
Arkansas [a]	2,347	(5)%	(5)%	2,460	(1)%
Colorado	4,115	—%	16%	3,548	(14)%
Iowa	4,611	10%	3%	4,460	6%
Kansas [a]	3,204	8%	6%	3,032	2%
Nebraska	4,169	10%	4%	4,016	6%
Wyoming	5,093	9%	12%	4,552	(4)%
Combined [b]	4,297	7%	7%	4,008	—%

(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 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 September 30,			Nine Months Ended September 30,		
	2019	2018	Variance	2019	2018	Variance
	(in thousands)					
Revenue	$ 25,811	$ 24,491	$ 1,320	$ 75,764	$ 71,173	$ 4,591
Operations and maintenance	9,229	7,434	1,795	27,750	25,520	2,230
Depreciation and amortization	4,760	3,978	782	14,069	11,922	2,147
Total operating expense	13,989	11,412	2,577	41,819	37,442	4,377
Adjusted operating income [a]	$ 11,822	$ 13,079	$ (1,257)	$ 33,945	$ 33,731	$ 214

(a) Due to the changes in our segment disclosures discussed in Note 3 of the Notes to Condensed Consolidated Financial Statements, Power Generation Adjusted operating income was revised for the three and nine months ended September 30, 2018, which resulted in a decrease of $(1.4) million and $(4.4) million, respectively.

Results of Operations for Power Generation for the Three and Nine Months Ended September 30, 2019 Compared to the Three and Nine Months Ended September 30, 2018:

Revenue increased in the current year due to increased wind MWh sold and higher PPA prices. Operating expenses increased in the current year primarily due to higher depreciation and property taxes from new wind assets.

The following table summarizes MWh for our Power Generation segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Quantities Sold, Generated and Purchased (MWh) [a]				
Sold				
Black Hills Colorado IPP [b]	275,867	304,102	692,156	745,365
Black Hills Wyoming [c]	162,668	160,011	476,430	470,072
Black Hills Electric Generation [d]	30,912	—	112,461	—
Total Sold	469,447	464,113	1,281,047	1,215,437
Generated				
Black Hills Colorado IPP [b]	275,867	304,102	692,156	745,365
Black Hills Wyoming [c]	142,219	144,476	407,001	407,324
Black Hills Electric Generation [d]	30,912	—	112,461	—
Total Generated	448,998	448,578	1,211,618	1,152,689
Purchased				
Black Hills Wyoming [c]	16,865	16,685	56,205	65,724
Total Purchased	16,865	16,685	56,205	65,724

(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 by Black Hills Electric Generation's acquisition of new wind assets.

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

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Contracted power plant fleet availability:				
Coal-fired plant	98.0%	97.9%	95.2%	93.9%
Natural gas-fired plants [(a)]	97.6%	99.3%	98.4%	99.4%
Wind [(b)]	81.9%	N/A	93.4%	N/A
Total availability	93.6%	98.9%	96.5%	98.0%
Wind capacity factor [(b)]	15.0%	N/A	22.1%	N/A

(a) 2019 included a planned outage at Pueblo Airport Generating Station.
(b) Change from the prior year is driven by Black Hills Electric Generation's acquisition of new wind assets.

Mining

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Three Months Variance	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018	Nine Months Variance
	(in thousands)					
Revenue	$ 15,552	$ 17,301	$ (1,749)	$ 45,026	$ 51,328	$ (6,302)
Operations and maintenance	9,900	10,761	(861)	28,988	32,807	(3,819)
Depreciation, depletion and amortization	2,278	1,989	289	6,687	5,874	813
Total operating expenses	12,178	12,750	(572)	35,675	38,681	(3,006)
Adjusted operating income	$ 3,374	$ 4,551	$ (1,177)	$ 9,351	$ 12,647	$ (3,296)

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

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Tons of coal sold	969	1,078	2,720	3,119
Cubic yards of overburden moved	2,341	2,361	6,380	6,763
Revenue per ton	$ 15.47	$ 15.54	$ 15.90	$ 15.92

Results of Operations for Mining for the Three Months Ended September 30, 2019 Compared to the Three Months Ended September 30, 2018:

Current year revenue decreased due to 10% fewer tons sold driven primarily by unplanned generation facility outages. Operating expenses decreased primarily due to lower royalties and production taxes on decreased revenues.

Results of Operations for Mining for the Nine Months Ended September 30, 2019 Compared to the Nine Months Ended September 30, 2018:

Current year revenue decreased due to 13% fewer tons sold driven primarily by planned and unplanned generation facility outages. Operating expenses decreased primarily due to lower royalties and production taxes on decreased revenues and lower fuel, labor and major maintenance expenses.

Corporate and Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2019	2018	Variance	2019	2018	Variance
	(in thousands)					
Adjusted operating income (loss) [(a)]	$ (34)	$ (178)	$ 144	$ (439)	$ (2,709)	$ 2,270

(a) Due to the changes in our segment disclosures as discussed in Note 3 of the Notes to Condensed Consolidated Financial Statements, Corporate and Other Adjusted operating income (loss) was revised for the three and nine months ended September 30, 2018, which resulted in a decrease of $(0.2) million and $(0.4) million, respectively.

Results of Operations for Corporate and Other for the Nine Months Ended September 30, 2019 Compared to the Three and Nine Months Ended September 30, 2018:

The variance in Adjusted operating income (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, Impairment of investment, Other income (expense) and Income tax benefit (expense) for the Three Months Ended September 30, 2019 Compared to the Three Months Ended September 30, 2018.

Impairment of Investment

For the three months ended September 30, 2019, we recorded a non-cash write-down of $20 million in our investment in equity securities of a privately held oil and gas company. The impairment was triggered by a deterioration in earnings performance of the privately held oil and gas company and an adverse change in future natural gas prices. See Note 21 of the Notes to Condensed Consolidated Financial Statements for additional details.

Income Tax Benefit (Expense)

Income tax benefit (expense) for the three months ended September 30, 2019 was $(2.5) million compared to $(7.5) million for the same period in 2018. The decrease in tax expense was primarily due to a prior year $(5.3) million income tax expense associated with changes in the previously estimated impact of tax reform on deferred income taxes.

For the three months ended September 30, 2019 the effective tax rate was 14.0% compared to 7.6% excluding the tax reform adjustments, for the same period in 2018. The higher effective tax rate is primarily due to a prior year state tax benefit.

Consolidated Interest expense, Impairment of investment, Other income (expense) and Income tax benefit (expense) for the Nine Months Ended September 30, 2019 Compared to the Nine Months Ended September 30, 2018.

Impairment of Investment

For the nine months ended September 30, 2019, we recorded a non-cash write-down of $20 million in our investment in equity securities of a privately held oil and gas company. The impairment was triggered by a deterioration in earnings performance of the privately held oil and gas company and an adverse change in future natural gas prices. See Note 21 of the Notes to Condensed Consolidated Financial Statements for additional details.

Income Tax Benefit (Expense)

Income tax benefit (expense) for the nine months ended September 30, 2019 was $(22) million compared to $12 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 $(7.5) million income tax expense associated with changes in the previously estimated impact of tax reform on deferred income taxes.

For the nine months ended September 30, 2019 the effective tax rate was 13.6% compared to 17.1% excluding the legal entity restructuring and tax reform adjustments, for the same period in 2018. The lower effective tax rate is primarily due to $5.0 million of federal production tax credits and related state investment tax credits associated with new wind assets, a $1.0 million tax benefit for deferred tax amortization related to tax reform.

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

There have been no material changes in Liquidity and Capital Resources from those reported in Item 7 of our 2018 Annual Report on Form 10-K filed with the SEC except as described below.

Collateral Requirements

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 September 30, 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 seven states and are working with 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. These agreements 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 nine months ended September 30, 2019 (in thousands):

Cash provided by (used in):	2019	2018	Variance
Operating activities	$ 386,075	$ 378,722	$ 7,353
Investing activities	$ (593,272)	$ (281,771)	$ (311,501)
Financing activities	$ 199,827	$ (101,949)	$ 301,776

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

Operating Activities

Net cash provided by operating activities was $386 million for the nine months ended September 30, 2019, compared to net cash provided by operating activities of $379 million for the same period in 2018 for an increase of $7 million. The variance was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $19 million higher for the nine months ended September 30, 2019 compared to the same period in the prior year;

- Net cash inflows from changes in operating assets and liabilities were $28 million for the nine months ended September 30, 2019, compared to net cash inflows of $42 million in the same period in the prior year. This $14 million decrease was primarily due to:

    - Cash inflows increased by approximately $48 million primarily as a result of higher collections of accounts receivable for the nine months ended September 30, 2019 compared to the same period in the prior year;

    - Cash outflows increased by approximately $3 million as a result of decreases in accounts payable and accrued liabilities driven by higher employee costs and other working capital requirements; and

    - Cash inflows decreased by approximately $66 million as a result of changes in the timing of recovery from fuel cost adjustments as well as 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 $593 million for the nine months ended September 30, 2019, compared to net cash used in investing activities of $282 million for the same period in 2018 for a variance of $311 million. The variance was primarily attributable to:

- Capital expenditures of approximately $593 million for the nine months ended September 30, 2019 compared to $278 million for the same period in the prior year. Higher current year expenditures are driven by higher programmatic safety, reliability and integrity spending at our Gas Utilities and Electric Utilities segments, the 35-mile Natural Bridge pipeline project at our Gas Utilities segment, the Busch Ranch II wind project at our Power Generation segment and construction of the final segment of the 175-mile transmission line from Rapid City, South Dakota, to Stegall, Nebraska at our Electric Utilities segment.

- A $24 million investment made in the prior year partially offset by an $18 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 provided by financing activities for the nine months ended September 30, 2019 was $200 million, compared to $102 million of net cash used in financing activities for the same period in 2018 for a variance of $302 million. This variance is primarily due to:

- We amended our Corporate term loan due July 30, 2020, which increased our debt to $400 million from $300 million;
- Current year issuance of common stock for net proceeds of $99 million through our ATM equity offering program;
- Current year net short-term borrowings of $109 million driven by increased capital expenditures;
- In the prior year, $99 million of net proceeds from the August 17, 2018 debt transaction was used to repay short-term debt;
- $15 million of higher current year dividend payments; and
- Payments for other financing activities decreased by $8.4 million, which was primarily driven by prior year financing costs associated with the July 30, 2018 and August 17, 2018 debt transactions.

Dividends

Dividends paid on our common stock totaled $92 million for the nine months ended September 30, 2019, or $0.505 per share per quarter. On October 31, 2019, our board of directors declared a quarterly dividend of $0.535 per share payable December 1, 2019, equivalent to an annual dividend of $2.14 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.

Financing Transactions and Short-Term Liquidity

Revolving Credit Facility and CP Program

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

Credit Facility	Expiration	Current Capacity	Short-term borrowings at September 30, 2019	Letters of Credit at September 30, 2019	Available Capacity at September 30, 2019
Revolving Credit Facility and CP Program	July 30, 2023	$ 750	$ 295	$ 18	$ 437

The weighted average interest rate on short-term borrowings at September 30, 2019 was 2.43%. Short-term borrowing activity for the nine months ended September 30, 2019 was (dollars in millions):

	For the Nine Months Ended September 30, 2019
Maximum amount outstanding - short-term borrowing (based on daily outstanding balances)	$ 295
Average amount outstanding - short-term borrowing (based on daily outstanding balances)	$ 171
Weighted average interest rates - short-term borrowing	2.59%

Covenant Requirements

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. 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 September 30, 2019. See Note 8 of the Notes to Condensed Consolidated Financial Statements for more information.

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 September 30, 2019, we were in compliance with these covenants.

Financing Activities

Financing activities for the nine months ended September 30, 2019 consisted of the following:

- We issued a total of 1,328,332 shares of common stock under the ATM equity offering program for proceeds of $99 million, net of $1.0 million in commissions. As of September 30, 2019, there were no shares that were sold, but not settled.

- On June 17, 2019, we amended our Corporate term loan due July 30, 2020. This amendment increased total commitments to $400 million from $300 million, extended the term through June 17, 2021 and continues to have substantially similar terms and covenants as the amended and restated Revolving Credit Facility. The net proceeds were used to pay down short-term debt. Proceeds from the October 3, 2019 debt transaction were used to repay this term loan.

- Short-term borrowings from our CP Program and Revolver.

On October 3, 2019, we completed a public debt offering of $700 million principal amount in senior unsecured notes. The debt offering consisted of $400 million of 3.05% 10-year senior notes due October 15, 2029 and $300 million of 3.875% 30-year senior notes due October 15, 2049. Proceeds were used to repay the $400 million Corporate term loan due June 17, 2021, retire the $200 million 5.875% senior notes due July 15, 2020, repay a portion of short-term debt.

Future Financing Plans

We will continue to assess debt and equity needs to support our capital expenditure plan.

Credit Ratings

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.

The following table represents the credit ratings and outlook and risk profile of BHC at September 30, 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 August 29, 2019, Fitch affirmed our BBB+ rating and maintained a Stable outlook.

The following table represents the credit ratings of South Dakota Electric at September 30, 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 October 15, 2019, Moody's affirmed A1 rating.
(c) On August 29, 2019, Fitch affirmed A rating.

Capital Requirements

Capital Expenditures

	Actual	Planned	Planned	Planned	Planned	Planned
Capital Expenditures by Segment	Nine Months Ended September 30, 2019 [(a)]	2019 [(b)]	2020	2021	2022	2023
(in millions)						
Electric Utilities [(c)]	$ 147	$ 215	$ 229	$ 203	$ 170	$ 137
Gas Utilities [(c)]	367	490	361	297	274	303
Power Generation	79	84	7	9	11	6
Mining	6	8	8	12	9	9
Corporate and Other	15	23	18	22	11	12
	$ 614	$ 820	$ 623	$ 543	$ 475	$ 467

(a) Expenditures for the nine months ended September 30, 2019 include the impact of accruals for property, plant and equipment.
(b) Includes actual capital expenditures for the nine months ended September 30, 2019.
(c) Planned capital expenditures increased for 2019 through 2023 primarily due to increased programmatic safety, reliability and 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 except for the items described in Notes 8, 16, and 20 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Off-Balance Sheet Commitments

There have been no significant changes to off-balance sheet commitments from those previously disclosed in Item 7 of our 2018 Annual Report on Form 10-K filed with the SEC except for the items described in Note 8 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

Information regarding our quantitative and qualitative disclosures about market risk is disclosed in Item 7A of our Annual Report on Form 10-K. During the nine months ended September 30, 2019, there were no material changes to our quantitative and qualitative disclosures about market risk.

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 September 30, 2019. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective at September 30, 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 September 30, 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 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 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). Eighth Supplemental Indenture dated as of October 3, 2019 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on October 4, 2019).
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 10.1	First Amendment dated as of June 17, 2019 to Amended and Restated Credit Agreement dated as of July 30, 2018, among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8–K filed on June 17, 2019).
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
104	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)

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

Table of Contents

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: November 5, 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: November 5, 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: November 5, 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 September 30, 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: November 5, 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 September 30, 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: November 5, 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 September 30, 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 September 30, 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 September 30, 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.