Section 1: 10-Q (10-Q)

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, 2018

OR

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

Commission File Number 001-31303

Black Hills Corporation

Incorporated in South Dakota　　IRS Identification Number 46-0458824

7001 Mount Rushmore Road
Rapid City, South Dakota 57702
Registrant's telephone number (605) 721-1700
Former name, former address, and former fiscal year if changed since last report
NONE

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

Yes ☒　　No ☐

Indicate by check mark whether the Registrant has submitted electronically 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 ☒　　No ☐

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

Large accelerated filer ☒　　Accelerated filer ☐

Non-accelerated filer ☐　　Smaller reporting company ☐

Emerging growth company ☐

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

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

Yes ☐　　No ☒

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

Class	Outstanding at November 1, 2018

Common stock, $1.00 par value	59,974,620 shares

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GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
APSC	Arkansas Public Service Commission
Arkansas Gas	Black Hills Energy Arkansas, Inc., a direct, wholly-owned subsidiary of Black Hills Gas Inc.
ASC	Accounting Standards Codification
ASU	Accounting Standards Update issued by the FASB
ATM	At-the-market equity offering program
Availability	The availability factor of a power plant is the percentage of the time that it is available to provide energy.
Bbl	Barrel
BHC	Black Hills Corporation; the Company
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business of our utility companies
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Busch Ranch	Busch Ranch Wind Farm is a 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and AltaGas. Colorado Electric has a 50% ownership interest in the wind farm.
Busch Ranch II	Busch Ranch II wind project will be a 60 MW wind farm near Pueblo, Colorado, built by Black Hills Electric Generation to provide wind energy to Colorado Electric through a 25-year power purchase agreement.
CAPP	Customer Appliance Protection Plan
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Choice Gas Program	The unbundling of the natural gas service from the distribution component, which opens up the gas supply for competition allowing customers to choose from different natural gas suppliers. Black Hills Gas Distribution distributes the gas and Black Hills Energy Services is one of the Choice Gas suppliers.
CIAC	Contribution In Aid of Construction
City of Gillette	Gillette, Wyoming
Colorado Electric	Black Hills Colorado Electric, 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 and including the aggregate outstanding amount of RSNs) plus Consolidated Indebtedness (including letters of credit, certain guarantees issued and excluding RSNs) as defined within the current Credit Agreement.
CDD	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
CPCN	Certificate of Public Convenience and Necessity
CP Program	Commercial Paper Program
CPUC	Colorado Public Utilities Commission
CVA	Credit Valuation Adjustment
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)

Equity Unit	Each Equity Unit has a stated amount of $50, consisting of a purchase contract issued by BHC to purchase shares of BHC common stock and a 1/20, or 5% undivided beneficial ownership interest in $1,000 principal amount of BHC RSNs that were formerly due 2028 prior to the successful remarketing on August 17, 2018.
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
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 over a 30-year average.
Horizon Point	Corporate headquarters building in Rapid City, South Dakota, which was completed in 2017.
IPP	Independent power producer
IRS	United States Internal Revenue Service
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
LIBOR	London Interbank Offered Rate
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MWh	Megawatt-hours
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
OCA	Office of Consumer Advocate
Peak View Wind Project	$109 million 60 MW wind generating project for Colorado Electric, adjacent to Busch Ranch wind farm
PCA	Power Cost Adjustment
PPA	Power Purchase Agreement
Revolving Credit Facility	Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which was amended and restated on July 30, 2018 and now terminates on July 30, 2023.
RMNG	Rocky Mountain Natural Gas, a regulated gas utility acquired in the SourceGas Acquisition that provides regulated transmission and wholesale natural gas service to Black Hills Gas in western Colorado (doing business as Black Hills Energy)
RSNs	Remarketable junior subordinated notes, issued on November 23, 2015
SEC	U. S. Securities and Exchange Commission
SourceGas	SourceGas Holdings LLC and its subsidiaries, a gas utility owned by funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co. (NYSE:GE) that was acquired on February 12, 2016, and is now named Black Hills Gas Holdings, LLC (doing business as Black Hills Energy)
SourceGas Acquisition	The acquisition of SourceGas Holdings, LLC by Black Hills Utility Holdings
S&P	Standard and Poor's, a division of The McGraw-Hill Companies, Inc.
South Dakota Electric	Includes Black Hills Power operations in South Dakota, Wyoming and Montana
SSIR	System Safety and Integrity Rider
TCJA	Tax Cuts and Jobs Act enacted on December 22, 2017
Tech Services	Non-regulated product lines within Black Hills Corporation that 1) provide electrical system construction services to large industrial customers of our electric utilities, and 2) serve gas transportation customers throughout its service territory by constructing and maintaining customer-owner gas infrastructure facilities, typically through one-time contracts.
WPSC	Wyoming Public Service Commission
Wyodak Plant	Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, owned 80% by Pacificorp and 20% by Black Hills Energy South Dakota. Our WRDC mine supplies all of the fuel for the plant.
Wyoming Electric	Includes Cheyenne Light's electric utility operations

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(in thousands, except per share amounts)			
Revenue	$ 321,979	$ 335,611	$ 1,253,072	$ 1,224,968
Operating expenses:				
Fuel, purchased power and cost of natural gas sold	80,244	86,281	432,544	404,222
Operations and maintenance	115,477	109,258	350,099	335,707
Depreciation, depletion and amortization	49,046	47,109	146,345	140,636
Taxes - property, production and severance	11,905	12,408	39,181	38,866
Other operating expenses	222	996	1,993	5,996
Total operating expenses	256,894	256,052	970,162	925,427
Operating income	65,085	79,559	282,910	299,541
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(36,480)	(35,287)	(107,360)	(105,417)
Allowance for funds used during construction - borrowed	701	753	1,345	2,061
Capitalized interest	100	64	177	197
Interest income	382	402	1,012	700
Allowance for funds used during construction - equity	193	696	503	1,982
Other income (expense), net	(703)	189	(2,426)	(6)
Total other income (expense), net	(35,807)	(33,183)	(106,749)	(100,483)
Income before income taxes	29,278	46,376	176,161	199,058
Income tax benefit (expense)	(7,477)	(13,478)	11,784	(58,518)
Income from continuing operations	21,801	32,898	187,945	140,540
(Loss) from discontinued operations, net of tax	(857)	(1,300)	(5,627)	(3,485)
Net income	20,944	31,598	182,318	137,055
Net income attributable to noncontrolling interest	(3,994)	(3,935)	(10,447)	(10,674)
Net income available for common stock	$ 16,950	$ 27,663	$ 171,871	$ 126,381
Amounts attributable to common shareholders:				
Net income from continuing operations	$ 17,807	$ 28,963	$ 177,498	$ 129,866
Net (loss) from discontinued operations	(857)	(1,300)	(5,627)	(3,485)
Net income available for common stock	$ 16,950	$ 27,663	$ 171,871	$ 126,381
Earnings per share of common stock:				
Earnings (loss) per share, Basic -				
Income from continuing operations, per share	$ 0.33	$ 0.54	$ 3.33	$ 2.44
(Loss) from discontinued operations, per share	(0.02)	(0.02)	(0.10)	(0.06)
Earnings per share, Basic [a]	$ 0.32	$ 0.52	$ 3.22	$ 2.38
Earnings (loss) per share, Diluted -				
Income from continuing operations, per share	$ 0.32	$ 0.52	$ 3.26	$ 2.35
(Loss) from discontinued operations, per share	(0.02)	(0.02)	(0.10)	(0.06)
Earnings per share, Diluted [a]	$ 0.31	$ 0.50	$ 3.15	$ 2.29
Weighted average common shares outstanding:				
Basic	53,364	53,243	53,346	53,208

Diluted	54,819	55,432	54,508	55,254
Dividends declared per share of common stock	$ 0.475	$ 0.445	$ 1.425	$ 1.335

(a) EPS may not sum due to rounding.

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, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(in thousands)			
Net income	$ 20,944	$ 31,598	$ 182,318	$ 137,055
Other comprehensive income (loss), net of tax:				
Reclassification adjustments of benefit plan liability - prior service cost (net of tax (expense) benefit of $10 and $17 for the three months ended September 30, 2018 and 2017 and $29 and $52 for the nine months ended September 30, 2018 and 2017, respectively)	(34)	(32)	(104)	(94)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(138) and $(145) for the three months ended September 30, 2018 and 2017 and $(409) and $(445) for the nine months ended September 30, 2018 and 2017, respectively)	483	269	1,456	797
Derivative instruments designated as cash flow hedges:				
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax (expense) benefit of $(152) and $(249) for the three months ended September 30, 2018 and 2017 and $(456) and $(779) for the nine months ended September 30, 2018 and 2017, respectively)	560	464	1,682	1,449
Net unrealized gains (losses) on commodity derivatives (net of tax (expense) benefit of $0 and $94 for the three months ended September 30, 2018 and 2017 and $51 and $(442) for the nine months ended September 30, 2018 and 2017, respectively)	30	(160)	(168)	755
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax (expense) benefit of $3 and $95 for the three months ended September 30, 2018 and 2017 and $(187) and $344 for the nine months ended September 30, 2018 and 2017, respectively)	21	(166)	615	(590)
Other comprehensive income, net of tax	1,060	375	3,481	2,317
Comprehensive income	22,004	31,973	185,799	139,372
Less: comprehensive income attributable to noncontrolling interest	(3,994)	(3,935)	(10,447)	(10,674)
Comprehensive income available for common stock	$ 18,010	$ 28,038	$ 175,352	$ 128,698

See Note 14 for additional disclosures.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of		
	September 30, 2018	December 31, 2017	September 30, 2017
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 10,001	$ 15,420	$ 13,449
Restricted cash	3,241	2,820	2,683
Accounts receivable, net	152,796	248,330	150,325
Materials, supplies and fuel	122,618	113,283	122,866
Derivative assets, current	1,392	304	433
Income tax receivable, net	11,025	—	—
Regulatory assets, current	48,302	81,016	61,023
Other current assets	32,691	25,367	25,586
Current assets held for sale	2,854	84,242	8,653
Total current assets	384,920	570,782	385,018
Investments	41,202	13,090	12,947
Property, plant and equipment	5,819,000	5,567,518	5,499,557
Less: accumulated depreciation and depletion	(1,118,783)	(1,026,088)	(1,000,875)
Total property, plant and equipment, net	4,700,217	4,541,430	4,498,682
Other assets:			
Goodwill	1,299,454	1,299,454	1,299,454
Intangible assets, net	6,954	7,559	7,765
Regulatory assets, non-current	212,048	216,438	239,571
Other assets, non-current	17,143	10,149	11,626
Noncurrent assets held for sale	—	—	108,685
Total other assets, non-current	1,535,599	1,533,600	1,667,101
TOTAL ASSETS	$ 6,661,938	$ 6,658,902	$ 6,563,748

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, 2018	December 31, 2017	September 30, 2017
	(in thousands, except share amounts)		
LIABILITIES AND TOTAL EQUITY			
Current liabilities:			
Accounts payable	$ 115,900	$ 160,887	$ 94,790
Accrued liabilities	201,353	219,462	206,779
Derivative liabilities, current	1,154	2,081	1,458
Accrued income taxes, net	—	1,022	5,587
Regulatory liabilities, current	41,442	6,832	7,042
Notes payable	112,100	211,300	225,170
Current maturities of long-term debt	255,743	5,743	5,743
Current liabilities held for sale	2,538	41,774	7,701
Total current liabilities	730,230	649,101	554,270
Long-term debt	2,951,389	3,109,400	3,109,864
Deferred credits and other liabilities:			
Deferred income tax liabilities, net	292,753	336,520	618,315
Regulatory liabilities, non-current	508,846	478,294	198,189
Benefit plan liabilities	151,613	159,646	149,803
Other deferred credits and other liabilities	105,928	105,735	113,996
Non-current liabilities held for sale	—	—	23,329
Total deferred credits and other liabilities	1,059,140	1,080,195	1,103,632
Commitments and contingencies (See Notes 9, 11, 16, 17)			
Equity:			
Stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 53,661,863; 53,579,986; and 53,524,529 shares, respectively	53,662	53,580	53,525
Additional paid-in capital	1,157,214	1,150,285	1,147,922
Retained earnings	644,154	548,617	516,371
Treasury stock, at cost – 72,915; 39,064; and 41,457 shares, respectively	(4,072)	(2,306)	(2,448)
Accumulated other comprehensive income (loss)	(37,703)	(41,202)	(32,566)
Total stockholders' equity	1,813,255	1,708,974	1,682,804
Noncontrolling interest	107,924	111,232	113,178
Total equity	1,921,179	1,820,206	1,795,982
TOTAL LIABILITIES AND TOTAL EQUITY	$ 6,661,938	$ 6,658,902	$ 6,563,748

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,	
	2018	2017
Operating activities:	(in thousands)	
Net income	$ 182,318	$ 137,055
Loss from discontinued operations, net of tax	5,627	3,485
Income from continuing operations	187,945	140,540
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	146,345	140,636
Deferred financing cost amortization	5,682	6,212
Stock compensation	7,544	7,594
Deferred income taxes	(14,396)	65,536
Employee benefit plans	10,641	8,470
Other adjustments, net	7,668	(3,549)
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	(8,380)	(19,511)
Accounts receivable, unbilled revenues and other operating assets	72,061	103,963
Accounts payable and other operating liabilities	(86,604)	(112,288)
Regulatory assets - current	41,655	1,287
Regulatory liabilities - current	21,416	(4,328)
Contributions to defined benefit pension plans	(12,700)	(27,700)
Other operating activities, net	2,007	(1,410)
Net cash provided by operating activities of continuing operations	380,884	305,452
Net cash provided by (used in) operating activities of discontinued operations	(2,162)	13,978
Net cash provided by operating activities	378,722	319,430
Investing activities:		
Property, plant and equipment additions	(278,132)	(238,840)
Purchase of investment	(24,429)	—
Other investing activities	2,766	160
Net cash provided by (used in) investing activities of continuing operations	(299,795)	(238,680)
Net cash provided by (used in) investing activities of discontinued operations	18,024	(17,298)
Net cash provided by (used in) investing activities	(281,771)	(255,978)
Financing activities:		
Dividends paid on common stock	(76,309)	(71,334)
Common stock issued	1,079	3,562
Net (payments) borrowings of short-term debt	(99,200)	128,570
Long-term debt - issuances	700,000	—
Long-term debt - repayments	(603,307)	(104,307)
Distributions to noncontrolling interest	(13,755)	(12,884)
Other financing activities	(10,457)	(6,719)
Net cash provided by (used in) financing activities	(101,949)	(63,112)
Net change in cash, cash equivalents and restricted cash	(4,998)	340
Cash, cash equivalents and restricted cash at beginning of period	18,240	15,792
Cash, cash equivalents and restricted cash at end of period	$ 13,242	$ 16,132

See Note 15 for supplemental disclosure of cash flow information.

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

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2017 Annual Report on Form 10-K)

(1) MANAGEMENT'S STATEMENT

The unaudited Condensed Consolidated Financial Statements included herein have been prepared by Black Hills Corporation (together with our subsidiaries the "Company," "us," "we," or "our"), pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations; however, we believe that the footnotes adequately disclose the information presented. These Condensed Consolidated Financial Statements should be read in conjunction with the consolidated financial statements and the notes thereto included in our 2017 Annual Report on Form 10-K filed with the SEC.

Segment Reporting

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

On November 1, 2017, the BHC board of directors approved a complete divestiture of our Oil and Gas segment. The Oil and Gas segment assets and liabilities are classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, excluding certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. As of September 30, 2018, we have sold nearly all of our oil and gas assets and we closed our oil and gas office in August. Transaction closing for the last few assets and final accounting are expected within the fourth quarter. See Note 18 for more information on discontinued operations.

Use of Estimates and Basis of Presentation

The information furnished in the accompanying Condensed Consolidated Financial Statements reflects certain estimates required and all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the September 30, 2018, December 31, 2017, and September 30, 2017 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2018 and September 30, 2017, and our financial condition as of September 30, 2018, December 31, 2017, and September 30, 2017, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

Cash and Cash Equivalents and Restricted Cash

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

Investments

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

Recently Issued Accounting Standards

Leases, ASU 2016-02

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which supersedes ASC 840, Leases. This ASU requires lessees to recognize a right-of-use asset and lease liability on the balance sheet for most leases, whereas today only financing-type lease liabilities (capital leases) are recognized on the balance sheet. In addition, the definition of a lease has been revised in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement, which may result in changes to the classification of an arrangement as a lease. The ASU does not significantly change the lessees' recognition, measurement and presentation of expenses and cash flows from the previous accounting standard. Lessors' accounting under the ASU is largely unchanged from the previous accounting standard. The ASU expands the disclosure requirements of lease arrangements. Under the current guidance, lessees and lessors will use a modified retrospective transition approach, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. The guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted. In January 2018, the FASB issued amendments to the new lease standard, ASU No. 2018-01, allowing an entity to elect not to assess whether certain land easements are, or contain, leases when transitioning to the new lease standard. The FASB also issued additional amendments to the new lease standard in July 2018, ASU No. 2018-11, allowing companies to adopt the new standard with a cumulative effect adjustment as of the beginning of the year of adoption with prior year comparative financial information and disclosures remaining as previously reported.

We expect to adopt this standard on January 1, 2019. For existing or expired land easements that were not previously accounted for as a lease, we anticipate electing the practical expedient which provides for no assessment of these easements. Further, we anticipate adopting the new standard with a cumulative effect adjustment with prior year comparative financial information remaining as previously reported when transitioning to the new standard. The standard also provides a transition practical expedient, commonly referred to as the “package of three”, that must be taken together and allows entities to (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. We expect to elect the “package of three” practical expedient. We continue to evaluate the additional transition practical expedients available under the guidance. At this time, we do not believe the implementation of this standard will have a material impact on our financial position, results of operations or cash flows. We continue to develop our process of identifying and categorizing our lease contracts and evaluating our current business processes relating to leases. We have selected, configured, and tested a new lease software solution and will be entering lease data into the new system in preparation for the January 1, 2019 standard adoption. We also continue to monitor utility industry lease implementation guidance that may change existing and future lease classification.

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

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

Simplifying the Test for Goodwill Impairment, ASU 2017-04

In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment (Topic 350)* by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the amount of goodwill allocated to that reporting unit. The new standard is effective for interim and annual reporting periods beginning after December 15, 2019, applied on a prospective basis with early adoption permitted. We do not anticipate the adoption of this standard to have any impact on our financial position, results of operations or cash flows.

Recently Adopted Accounting Standards

Revenue from Contracts with Customers, ASU 2014-09

Effective January 1, 2018, we adopted ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, and its related amendments (collectively known as ASC 606). Under this standard, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In addition, the standard requires disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. We applied the five-step method outlined in the ASU to all in-scope revenue streams and elected the modified retrospective implementation method. Implementation of the standard did not have a material impact on our financial position, results of operations or cash flows. Implementation of the standard did not have a significant impact on the measurement or recognition of revenue; therefore, no cumulative adoption adjustment to the opening balance of Retained earnings at the date of initial application was necessary. The additional disclosures required by the ASU are included in Note 2.

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

Effective January 1, 2018, we adopted ASU 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost*. The standard requires employers to report the service cost component in the same line item(s) as other compensation costs, and requires the other components of net periodic pension and post-retirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component may be eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. The capitalization of only the service cost component of net periodic pension and post-retirement benefit costs in assets was applied on a prospective basis for the nine months ended September 30, 2018. Retrospective impact was not material and therefore prior year presentation was not changed. For our rate-regulated entities, we capitalize the other components of net periodic benefit costs into regulatory assets or regulatory liabilities and maintain a FERC-to-GAAP reporting difference for these capitalized costs. The presentation changes required for net periodic pension and post-retirement costs resulted in offsetting changes to Operating income and Other income. Implementation of the standard did not have a material impact on our financial position, results of operations or cash flows.

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

Effective January 1, 2018, we adopted ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force).* This ASU requires changes in the presentation of certain items, including but not limited to, debt prepayment or debt extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies and distributions received from equity method investees. We implemented this standard effective January 1, 2018 using the retrospective transition method. This standard had no impact on our financial position, results of operations or cash flows.

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

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

(2) REVENUE

Revenue Recognition

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

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

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

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

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

The following 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, 2018. Sales tax and other similar taxes are excluded from revenues.

Three Months Ended September 30, 2018	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer types:			(in thousands)			
Retail	$ 157,049	$ 88,559	$ —	$ 16,751	$ (7,941)	$ 254,418
Transportation	—	30,079	—	—	(267)	29,812
Wholesale	8,255	—	14,485	—	(13,047)	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	14,485	16,751	(26,297)	320,163
Other revenues	231	1,011	9,118	550	(9,094)	1,816
Total revenues	$ 184,790	$ 131,676	$ 23,603	$ 17,301	$ (35,391)	$ 321,979
Timing of revenue recognition:						
Services transferred at a point in time	$ —	$ —	$ —	$ 16,751	$ (7,941)	$ 8,810
Services transferred over time	184,559	130,665	14,485	—	(18,356)	311,353
Revenue from contracts with customers	$ 184,559	$ 130,665	$ 14,485	$ 16,751	$ (26,297)	$ 320,163

Nine Months Ended September 30, 2018	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer types:			(in thousands)			
Retail	$ 449,482	$ 565,816	$ —	$ 49,653	$ (23,761)	$ 1,041,190
Transportation	—	100,760	—	—	(977)	99,783
Wholesale	25,497	—	41,161	—	(36,874)	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	41,161	49,653	(78,110)	1,245,981
Other revenues	2,218	3,106	27,429	1,675	(27,337)	7,091
Total revenues	$ 531,961	$ 706,640	$ 68,590	$ 51,328	$ (105,447)	$ 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	41,161	—	(54,349)	1,220,089
Revenue from contracts with customers	$ 529,743	$ 703,534	$ 41,161	$ 49,653	$ (78,110)	$ 1,245,981

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

Revenue Not in Scope of ASC 606

Other revenues included in the tables above include our revenue accounted for under separate accounting guidance, including lease revenue under ASC 840, derivative revenue under ASC 815 and alternative revenue programs revenue under ASC 980. The majority of our lease revenue is related to a 20-year power sale agreement between Colorado IPP and affiliate Colorado Electric. This agreement is accounted for as a direct financing lease whereby Colorado IPP receives revenue for energy delivered and related capacity payments. This lease revenue is eliminated in our consolidated revenues.

Significant Judgments and Estimates

TCJA Revenue Reserve

The TCJA or "tax reform" signed into law on December 22, 2017, reduced the federal corporate income tax rate from 35% to 21% effective for tax years beginning after December 31, 2017. Black Hills has been collaborating with utility commissions in the states in which it provides utility service to deliver to customers the benefits of a lower corporate federal income tax rate beginning in 2018 with the passage of the TCJA. We have received state utility commission approvals to provide the benefits of federal tax reform to utility customers in six states. We estimated and recorded a reserve to revenue of approximately $6.0 million and $29 million during the three and nine months ended September 30, 2018, respectively. As of September 30, 2018, $7.9 million has been returned to customers and approximately $21 million remains in reserve.

Unbilled Revenue

Revenues attributable to natural gas and electricity delivered to customers but not yet billed are estimated and accrued, and the related costs are charged to expense. Factors influencing the determination of unbilled revenues include estimates of delivered sales volumes based on weather information and customer consumption trends.

Contract Balances

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

Practical Expedients

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

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

(3) BUSINESS SEGMENT INFORMATION

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

Three Months Ended September 30, 2018	External Operating Revenue		Inter-company Operating Revenue			
	Contract Customers	Other Revenues	Contract Customers	Other Revenues	Total Revenues	Net income (loss) from continuing operations
Segment:						
Electric Utilities	$ 179,527	$ 231	$ 5,032	$ —	$ 184,790	$ 21,578
Gas Utilities	130,390	1,011	275	—	131,676	(13,277)
Power Generation (b)	1,437	348	13,048	8,770	23,603	6,691
Mining	8,809	226	7,942	324	17,301	3,572
Corporate and Other	—	—	—	—	—	(757)
Inter-company eliminations	—	—	(26,297)	(9,094)	(35,391)	—
Total	$ 320,163	$ 1,816	$ —	$ —	$ 321,979	$ 17,807

Under our modified retrospective adoption of ASU 2014-09, revenues for the three and nine months ended September 30, 2017 are not presented by contract type.

Three Months Ended September 30, 2017	External Operating Revenue	Inter-company Operating Revenue	Net income (loss) from continuing operations
Segment:			
Electric Utilities	$ 181,238	$ 2,333	$ 27,324
Gas Utilities	142,821	73	(4,329)
Power Generation (b)	1,810	21,117	6,155
Mining	9,742	7,751	3,477
Corporate and Other	—	—	(3,664)
Inter-company eliminations	—	(31,274)	—
Total	$ 335,611	$ —	$ 28,963

Nine Months Ended September 30, 2018	External Operating Revenue		Inter-company Operating Revenue			
	Contract Customers	Other Revenues	Contract Customers	Other Revenues	Total Revenues	Net income (loss) from continuing operations
Segment:						
Electric Utilities	$ 513,270	$ 2,218	$ 16,473	$ —	$ 531,961	$ 63,313
Gas Utilities (a)	702,532	3,106	1,002	—	706,640	93,182
Power Generation (b)	4,287	1,066	36,874	26,363	68,590	17,319
Mining	25,892	701	23,761	974	51,328	9,561
Corporate and Other	—	—	—	—	—	(5,877)
Inter-company eliminations	—	—	(78,110)	(27,337)	(105,447)	—
Total	$ 1,245,981	$ 7,091	$ —	$ —	$ 1,253,072	$ 177,498

Nine Months Ended September 30, 2017	External Operating Revenue	Inter-company Operating Revenue	Net income (loss) from continuing operations
Segment:			
Electric Utilities	$ 518,925	$ 9,123	$ 68,386
Gas Utilities	674,161	90	41,409
Power Generation [b]	5,382	62,907	18,017
Mining	26,500	22,485	9,048
Corporate and Other [c]	—	—	(6,994)
Inter-company eliminations	—	(94,605)	—
Total	$ 1,224,968	$ —	$ 129,866

(a) Net income from continuing operations available for common stock for the nine months ended September 30, 2018 included a $49 million tax benefit resulting from legal entity restructuring. See Note 19 Income Taxes of the Notes to Condensed Consolidated Financial Statements for more information.

(b) Net income from continuing operations available for common stock for the three and nine months ended September 30, 2018 and September 30, 2017 reflects net income attributable to noncontrolling interests of $4.0 million and $10.4 million, and $3.9 million and $10.6 million, respectively.

(c) Net income (loss) from continuing operations available for common stock for the nine months ended September 30, 2017 included a $1.4 million tax benefit recognized from carryback claims for specified liability losses involving prior tax years.

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, 2018	December 31, 2017	September 30, 2017
Segment:			
Electric Utilities [a]	$ 2,853,414	$ 2,906,275	$ 2,911,919
Gas Utilities	3,433,316	3,426,466	3,288,104
Power Generation [a]	122,428	60,852	64,357
Mining	72,602	65,455	66,700
Corporate and Other	177,324	115,612	115,330
Discontinued operations	2,854	84,242	117,338
Total assets	$ 6,661,938	$ 6,658,902	$ 6,563,748

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

(4) ACCOUNTS RECEIVABLE

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

September 30, 2018	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 43,108	$ 31,381	$ (386)	$ 74,103
Gas Utilities	48,638	24,768	(2,188)	71,218
Power Generation	1,696	—	—	1,696
Mining	3,749	—	—	3,749
Corporate	2,030	—	—	2,030
Total	$ 99,221	$ 56,149	$ (2,574)	$ 152,796

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

September 30, 2017	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 42,716	$ 29,762	$ (494)	$ 71,984
Gas Utilities	49,842	24,516	(1,190)	73,168
Power Generation	1,010	—	—	1,010
Mining	3,534	—	—	3,534
Corporate	629	—	—	629
Total	$ 97,731	$ 54,278	$ (1,684)	$ 150,325

(5) REGULATORY ACCOUNTING

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

	September 30, 2018	December 31, 2017	September 30, 2017
Regulatory assets			
Deferred energy and fuel cost adjustments [(a)]	$ 29,976	$ 20,187	$ 20,559
Deferred gas cost adjustments [(a)]	720	31,844	12,833
Gas price derivatives [(a)]	6,192	11,935	11,297
Deferred taxes on AFUDC [(b)]	7,804	7,847	15,645
Employee benefit plans [(c)]	106,734	109,235	105,671
Environmental [(a)]	972	1,031	1,051
Asset retirement obligations [(a)]	526	517	514
Loss on reacquired debt [(a)]	21,431	20,667	21,067
Renewable energy standard adjustment [(a)]	1,131	1,088	1,956
Deferred taxes on flow through accounting [(c) (e)]	29,342	26,978	41,900
Decommissioning costs [(b)]	11,052	13,287	13,989
Gas supply contract termination [(a)]	15,745	20,001	21,402
Other regulatory assets [(a)]	28,725	32,837	32,710
Total regulatory assets	260,350	297,454	300,594
Less current regulatory assets	(48,302)	(81,016)	(61,023)
Regulatory assets, non-current	$ 212,048	$ 216,438	$ 239,571
Regulatory liabilities			
Deferred energy and gas costs [(a)]	$ 15,980	$ 3,427	$ 3,780
Employee benefit plan costs and related deferred taxes [(c) (e)]	39,332	40,629	66,620
Cost of removal [(a)]	146,177	130,932	125,360
Excess deferred income taxes [(c) (d)]	316,625	301,553	52
TCJA revenue reserve	20,592	—	—
Other regulatory liabilities [(c)]	11,582	8,585	9,419
Total regulatory liabilities	550,288	485,126	205,231
Less current regulatory liabilities	(41,442)	(6,832)	(7,042)
Regulatory liabilities, non-current	$ 508,846	$ 478,294	$ 198,189

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

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

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

(d) The increase in the regulatory tax liability is primarily related to the revaluation of deferred income tax balances at the lower income tax rate. As of September 30, 2018 and December 31, 2017, all of the liability was classified as non-current due to uncertainties around the timing and other regulatory decisions that will affect the amount of regulatory tax liability amortized and returned to customers through rate reductions or other revenue offsets.

(e) The variance to the prior periods is primarily due to the decrease in federal income tax from 35% to 21% as a result of the TCJA.

Regulatory Matters

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

TCJA revenue reserve - The TCJA signed into law on December 22, 2017, reduced the federal corporate income tax rate from 35% to 21%. Effective January 1, 2018, the key impact of tax reform on existing utility revenues/tariffs established prior to tax reform results primarily from the change in the federal tax rate from 35% to 21% (including the effects of tax gross-ups not yet approved) affecting current income tax expense embedded in those tariffs. Black Hills has been collaborating with utility commissions in the states in which it provides utility service to deliver to customers the benefits of a lower corporate federal income tax rate beginning in 2018 with the passage of the TCJA. We have received state utility commission approvals to provide the benefits of federal tax reform to utility customers in six states. We estimated and recorded a reserve to revenue of approximately $6.0 million and $29 million during the three and nine months ended September 30, 2018, respectively. As of September 30, 2018, $7.9 million has been returned to customers.

A list of states where benefits to customers of federal tax reform have been approved is summarized below.

State		Approximate 2018 Benefit for Customers	Start Date for Customer Benefits
Arkansas	$	9.7 million	October 2018
Colorado	$	10.8 million	July 2018
Iowa	$	2.4 million	June 2018
Kansas	$	1.9 million	April 2018
Nebraska	$	3.8 million	July 2018
South Dakota	$	7.7 million	October 2018

In support of returning benefits to customers, the three rate review requests filed in 2017 for Arkansas Gas, Wyoming Gas (Northwest Wyoming) and Rocky Mountain Natural Gas (a pipeline system in Colorado) were adjusted to include the benefits to customers of federal tax reform as discussed below.

Rate Reviews

<u>RMNG</u>

In Colorado, new rates for RMNG went into effect June 1, 2018 after an administrative law judge recommended approval of a settlement agreement and the CPUC took no further action. The settlement included $1.1 million in annual revenue increases and an extension of the SSIR to recover costs from 2018 through December 31, 2021. The annual increase is based on a return on equity of 9.9% and a capital structure of 46.63% equity and 53.37% debt. New rates are inclusive of customer benefits related to the TCJA.

<u>Wyoming Gas</u>

On July 16, 2018, the WPSC reached a bench decision approving our Wyoming Gas (Northwest Wyoming) settlement and stipulation with the OCA. We received the final order in the third quarter of 2018. The settlement provides for $1.0 million of new revenue, a return on equity of 9.6%, and a capital structure of 54.0% equity and 46.0% debt. New rates, inclusive of customer benefits related to the TCJA, were effective September 1, 2018.

<u>Arkansas Gas</u>

On October 5, 2018, Arkansas Gas received approval from the APSC for a general rate increase. The new rates will generate approximately $12 million of new annual revenue. The APSC's approval also allows Arkansas Gas to include $11 million of revenue that is currently being collected through certain rider mechanisms in the new base rates. The new revenue increase is based on a return on equity of 9.61% and a capital structure of 49.1% equity and 50.9% debt. New rates, inclusive of customer benefits related to the TCJA, were effective October 15, 2018.

<u>Wyoming Electric</u>

On October 31, Wyoming Electric received approval from the WPSC for a comprehensive, multi-year settlement regarding its PCA Application filed earlier in 2018. Wyoming Electric's PCA permits the recovery of costs associated with fuel, purchased electricity and other specified costs, including the portion of the company's energy that is delivered from the Wygen I PPA with Black Hills Wyoming. Wyoming Electric will provide an aggregate $7.0 million in customer credits through the PCA mechanism in 2018, 2019 and 2020 to resolve all outstanding issues relating to its current and prior PCA filings. The settlement also stipulates the adjustment for the variable cost segment of the Wygen I PPA with Wyoming Electric will escalate by 3.0% annually through 2022, providing price certainty for Wyoming Electric and its customers. As of September 30, 2018, we have recorded a liability of $4.5 million related to the PCA.

Nebraska Gas
On June 1, 2018, Nebraska Gas Distribution filed an application with the NPSC requesting a continuation of the SSIR beyond the expiration date of October 31, 2019. On September 5, 2018, the NSPC approved continuation of the SSIR tariff to December 31, 2020. The SSIR provides approximately $6.0 million of revenue annually on investments made prior to January 1, 2018, with investments after that date to be recovered through other methods. If a base rate review is filed prior to expiration of the rider, that rate request will include the remaining investment to be recovered.

Kansas Gas
On June 19, 2018, Kansas Gas received approval from the Kansas Corporation Commission to double annual eligible investments up to $8.0 million for safety related integrity investments under the Gas System Reliability rider.

(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, 2018	December 31, 2017	September 30, 2017
Materials and supplies	$ 73,777	$ 69,732	$ 70,284
Fuel - Electric Utilities	2,750	2,962	2,993
Natural gas in storage held for distribution	46,091	40,589	49,589
Total materials, supplies and fuel	$ 122,618	$ 113,283	$ 122,866

(7) INVESTMENTS

In February 2018, we contributed $28 million of assets in exchange for equity securities in a privately held company. The carrying value of our investment in the equity securities was determined using the cost method. We review this investment on a periodic basis to determine whether a significant event or change in circumstances has occurred that may have an adverse effect on the value of the investment. We estimate that the fair value of this cost method investment approximated or exceeded its carrying value as of September 30, 2018.

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

	September 30, 2018	December 31, 2017	September 30, 2017
Cost method investment	$ 28,134	$ —	$ —
Cash surrender value of life insurance contracts	13,068	13,090	12,947
Total investments	$ 41,202	$ 13,090	$ 12,947

(8) EARNINGS PER SHARE

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net income available for common stock	$ 16,950	$ 27,663	$ 171,871	$ 126,381
Weighted average shares - basic	53,364	53,243	53,346	53,208
Dilutive effect of:				
Equity Units [(a)]	1,344	2,015	1,060	1,872
Equity compensation	111	174	102	174
Weighted average shares - diluted	54,819	55,432	54,508	55,254

(a) Calculated using the treasury stock method.

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

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Equity compensation	12	—	15	—
Anti-dilutive shares	12	—	15	—

(9) 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, 2018		December 31, 2017		September 30, 2017	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$ —	$ 15,203	$ —	$ 26,848	$ —	$ 25,391
CP Program	112,100	—	211,300	—	225,170	—
Total	$ 112,100	$ 15,203	$ 211,300	$ 26,848	$ 225,170	$ 25,391

Revolving Credit Facility and CP Program

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

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

Our net payments under the CP Program during the nine months ended September 30, 2018 were $99 million and our notes outstanding as of September 30, 2018 were $112 million. As of September 30, 2018, the weighted average interest rate on CP Program borrowings was 2.42%.

Debt Covenants

Under our Revolving Credit Facility and term loan agreement (before each was amended and restated), we were required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. At September 30, 2018, our Consolidated Indebtedness to Capitalization Ratio was calculated by dividing (i) Consolidated Indebtedness (which included letters of credit and certain guarantees issued but excluded the RSNs), by (ii) Capital, which is Consolidated Indebtedness plus Consolidated Net Worth (which excluded noncontrolling interests in subsidiaries and included the aggregate outstanding amount of the RSNs). Under our amended and restated revolving Credit Facility and amended and restated term loan agreement, we are also required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00, but as of September 30, 2018 only, Consolidated Net Worth will include the amount receivable by the Company in connection with the common stock settlement under the purchase contracts which are part of the Equity Units, rather than the outstanding amount of the RSNs.

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

	As of September 30, 2018	Covenant Requirement	
Consolidated Indebtedness to Capitalization Ratio	61.4%	Less than	65%

As of September 30, 2018, we were in compliance with this covenant.

Current Maturities

As of September 30, 2018, our $250 million senior unsecured notes due January 11, 2019 and $5.7 million of principal due in the next twelve months on our Corporate term loan due June 7, 2021 are classified as Current maturities of long-term debt on our Condensed Consolidated Balance Sheets.

Long-Term Debt

On August 17, 2018, we issued $400 million principal amount, 4.350% senior unsecured notes due 2033. A portion of these notes were issued in a private exchange that resulted in the retirement of all $299 million principal amount of our RSNs due 2028. The remainder of the notes were sold for cash in a public offering, with the net proceeds being used to pay down short-term debt.

The issuance of these new senior notes was the culmination of a series of transactions that also included the contractually required remarketing of such RSNs on behalf of the holders of our Equity Units, with the proceeds being deposited as collateral to secure the obligations of those holders under the purchase contracts included in the Equity Units (see subsequent event in Note 10). As a result of the remarketing, the annual interest rate on such RSNs was automatically reset to 4.579% (however, because the RSNs were then immediately retired, no interest accrued at this reset rate).

On July 30, 2018, we amended and restated our unsecured term loan due August 2019. This amended and restated term loan, with $300 million outstanding at September 30, 2018, will now mature on July 30, 2020 and has substantially similar terms and covenants as the amended and restated Revolving Credit Facility. The interest cost associated with this term loan is 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 and Eurodollar borrowings were 0.000% and 0.700%, respectively, at September 30, 2018.

(10) EQUITY

A summary of the changes in equity is as follows:

Nine Months Ended September 30, 2018	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
		(in thousands)	
Balance at December 31, 2017	$ 1,708,974	$ 111,232	$ 1,820,206
Net income (loss)	171,871	10,447	182,318
Other comprehensive income	3,481	—	3,481
Dividends on common stock	(76,309)	—	(76,309)
Share-based compensation	4,871	—	4,871
Dividend reinvestment and stock purchase plan	220	—	220
Other stock transactions	147	—	147
Distribution to noncontrolling interest	—	(13,755)	(13,755)
Balance at September 30, 2018	$ 1,813,255	$ 107,924	$ 1,921,179

Nine Months Ended September 30, 2017	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
		(in thousands)	
Balance at December 31, 2016	$ 1,614,639	$ 115,495	$ 1,730,134
Net income (loss)	126,381	10,567	136,948
Other comprehensive income	2,317	—	2,317
Dividends on common stock	(71,334)	—	(71,334)
Share-based compensation	5,853	—	5,853
Dividend reinvestment and stock purchase plan	2,300	—	2,300
Redeemable noncontrolling interest	(886)	—	(886)
Cumulative effect of ASU 2016-09 implementation	3,714	—	3,714
Other stock transactions	(180)	—	(180)
Distribution to noncontrolling interest	—	(12,884)	(12,884)
Balance at September 30, 2017	$ 1,682,804	$ 113,178	$ 1,795,982

At-the-Market Equity Offering Program

On August 4, 2017, we renewed our ATM equity offering program which reset the size of the program to an aggregate value of up to $300 million. The renewed program, which allows us to sell shares of our common stock, is the same as the prior program other than the aggregate value increased from $200 million to $300 million. The shares may be offered from time to time pursuant to a sales agreement dated August 4, 2017. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. We did not issue any common shares during the nine months ended September 30, 2018 or September 30, 2017 under the ATM equity offering program.

Subsequent Event - Equity Units Settlement

On October 29, 2018, we announced the settlement rate for the stock purchase contracts that are components of the Equity Units issued November 23, 2015. The settlement rate was based upon the minimum settlement rate, as adjusted to account for past dividends, because the average of the closing price per share of Black Hills Corporation common stock on the New York Stock Exchange for the 20 consecutive trading days ending on October 29, 2018 exceeded the threshold appreciation price. Each holder of the Equity Units on that date, following payment of $50.00 for each unit which it holds, received 1.0655 shares of Black Hills Corporation common stock for each such unit. The holders' obligations to make such payments were satisfied with proceeds generated by the successful remarketing on August 17, 2018, of the RSNs that formerly constituted a component of the Equity Units.

Upon settlement of all outstanding stock purchase obligations, the Company received gross proceeds of approximately $299 million in exchange for approximately 6.372 million shares of common stock. Proceeds will be used to pay down the $250 million senior unsecured notes due January 11, 2019, with the balance used to pay down short-term debt.

As of November 1, 2018, after the Equity Units settlement, we had shares outstanding of approximately 59.97 million.

(11) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures as discussed in our 2017 Annual Report on Form 10-K.

Market Risk

Market risk is the potential loss that might occur as a result of an adverse change in market price or rate. We are exposed to the following market risks including, but not limited to:

- Commodity price risk associated with our retail natural gas marketing activities and our fuel procurement for certain gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt.

Credit Risk

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

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

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

Our derivative and hedging activities recorded in the accompanying Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Income and Condensed Consolidated Statements of Comprehensive Income are detailed below and in Note 12.

Utilities

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

For our regulated utilities' hedging plans, unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Condensed Consolidated Balance Sheets in accordance with state commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Condensed Consolidated Statements of Income.

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from October 2018 through May 2020; 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 effective portion of the gain or loss on these designated derivatives is reported in AOCI in the accompanying Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Fuel, purchased power and cost of natural gas sold in the accompanying Condensed Consolidated Statements of Income. Effectiveness of our hedging position is evaluated at inception of the hedge, upon occurrence of a triggering event and as of the end of each quarter.

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

	September 30, 2018		December 31, 2017		September 30, 2017	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	5,300,000	27	8,330,000	36	10,250,000	39
Natural gas options purchased, net	9,670,000	16	3,540,000	14	7,360,000	17
Natural gas basis swaps purchased	5,140,000	27	8,060,000	36	9,170,000	39
Natural gas over-the-counter swaps, net [(b)]	4,370,000	20	3,820,000	29	4,600,000	20
Natural gas physical contracts, net [(c)]	19,539,851	33	12,826,605	35	21,071,714	38

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(a) Term reflects the maximum forward period hedged.

(b) As of September 30, 2018, 2,236,000 MMBtus were designated as cash flow hedges for the natural gas over-the-counter swaps purchased.

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

Based on September 30, 2018 prices, a $0.1 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, 2018, the Company posted $0.7 million related to such provisions, which is included in Other current assets on the Condensed Consolidated Balance Sheets.

Financing Activities

At September 30, 2018, we had no outstanding interest rate swap agreements. Our last interest rate swap agreement with a $50 million notional value, which was designated to borrowings on our Revolving Credit Facility, expired in January 2017.

Discontinued Operations

Our Oil and Gas segment was exposed to risks associated with changes in the market prices of oil and gas. Through December 2017, we used exchange traded futures, swaps and options to hedge portions of our crude oil and natural gas production to mitigate commodity price risk and preserve cash flows. Hedge accounting was elected on the swaps and futures contracts. These transactions were designated upon inception as cash flow hedges, documented under accounting standards for derivatives and hedging and initially met prospective effectiveness testing. As a result of divesting our Oil and Gas assets, these activities were discontinued and there were no outstanding derivative agreements as of September 30, 2018 or December 31, 2017. At September 30, 2017, we had outstanding crude oil futures and swap contracts with notional volumes of 54,000 Bbls, crude oil option contracts with notional volumes of 9,000 Bbls and natural gas futures and swap contracts with notional volumes of 540,000 MMBtus.

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, 2018 and 2017 (in thousands). Note that this presentation does not reflect gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic profit or loss we realized when the underlying physical and financial transactions were settled.

Three Months Ended September 30, 2018

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (712)	Interest expense	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(18)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (730)		$ —

Three Months Ended September 30, 2017

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (713)	Interest expense	$ —
Commodity derivatives	Net (loss) from discontinued operations	295	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(34)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (452)		$ —

Nine Months Ended September 30, 2018

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (2,138)	Interest expense	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(802)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (2,940)		$ —

Nine Months Ended September 30, 2017

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (2,228)	Interest expense	$ —
Commodity derivatives	Net (loss) from discontinued operations	954	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(20)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (1,294)		$ —

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

	Three Months Ended September 30,	
	2018	2017
	(in thousands)	
Increase (decrease) in fair value:		
Forward commodity contracts	$ 30	$ (254)
Recognition of (gains) losses in earnings due to settlements:		
Interest rate swaps	712	713
Forward commodity contracts	18	(261)
Total other comprehensive income (loss) from hedging	$ 760	$ 198

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	Nine Months Ended September 30,	
	2018	2017
	(in thousands)	
Increase (decrease) in fair value:		
Forward commodity contracts	$ (219)	$ 1,197
Recognition of (gains) losses in earnings due to settlements:		