BLACK HILLS CORP /SD/
Form 10-Q
November 04, 2016

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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2016

OR

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

Commission File Number 001-31303

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

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

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

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act).
Large accelerated filer x Accelerated filer o
Non-accelerated filer o Smaller reporting company o

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

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

Class	Outstanding at October 31, 2016	
Common stock, $1.00 par value	53,147,805	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
ASC	Accounting Standards Codification
ASU	Accounting Standards Update issued by the FASB
ATM	At-the-market equity offering program
Bbl	Barrel
BHC	Black Hills Corporation; the Company
Black Hills Gas	Black Hills Gas, LLC, a subsidiary of Black Hills Gas Holdings, which was previously named SourceGas LLC.
Black Hills Gas Holdings	Black Hills Gas Holdings, LLC, a subsidiary of Black Hills Utility Holdings, which was previously named SourceGas Holdings LLC
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business of our utility companies
Black Hills Energy Arkansas Gas	Includes the acquired SourceGas utility Black Hills Energy Arkansas, Inc. utility operations
Black Hills Energy Colorado Electric	Includes Colorado Electric’s utility operations
Black Hills Energy Colorado Gas	Includes Black Hills Energy Colorado Gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution’s Colorado gas operations and RMNG
Black Hills Energy Iowa Gas	Includes Black Hills Energy Iowa gas utility operations
Black Hills Energy Kansas Gas	Includes Black Hills Energy Kansas gas utility operations
Black Hills Energy Nebraska Gas	Includes Black Hills Energy Nebraska gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution’s Nebraska gas operations
Black Hills Energy South Dakota Electric	Includes Black Hills Power operations in South Dakota, Wyoming and Montana
Black Hills Energy Wyoming Electric	Includes Cheyenne Light’s electric utility operations
Black Hills Energy Wyoming Gas	Includes Cheyenne Light’s natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution’s Wyoming gas operations
Black Hills Gas Distribution	Black Hills Gas Distribution, LLC, a company acquired in the SourceGas Acquisition that conducts the gas distribution operations in Colorado, Nebraska and Wyoming. It was formerly named SourceGas Distribution LLC.
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit

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 as defined within the current Credit Agreement.
Ceiling Test	Related to our Oil and Gas subsidiary, capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC plus the lower of cost or market value of unevaluated properties.
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)

Cheyenne Prairie	Cheyenne Prairie Generating Station is a 132 MW natural gas-fired generating facility jointly owned by Black Hills Power, Inc. and Cheyenne Light, Fuel and Power Company. Cheyenne Prairie was placed into commercial service on October 1, 2014.
CIAC	Contribution In Aid of Construction
City of Gillette	Gillette, Wyoming
Colorado Electric	Black Hills Colorado Electric Utility Company, LP, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado Gas	Black Hills Colorado Gas Utility Company, LP, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado Interstate Gas	Colorado Interstate Natural Gas Pricing Index
Colorado IPP	Black Hills Colorado IPP, LLC a 50.1% owned subsidiary of Black Hills Electric Generation
Cooling degree day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
Cost of Service Gas Program (COSG)	Proposed Cost of Service Gas Program designed to provide long-term natural gas price stability for the Company's utility customers, along with a reasonable expectation of customer savings over the life of the program.
CPCN	Certificate of Public Convenience and Necessity
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)
El Paso San Juan	El Paso San Juan Natural Gas Pricing Index
Equity Unit	Each Equity Unit has a stated amount of $50, consisting of a purchase contract issued by BHC to purchase shares of BHC common stock and a 1/20, or 5% undivided beneficial ownership interest in $1,000 principal amount of BHC RSNs due 2028.
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
Heating Degree Day	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
IPP	Independent power producer
IRS	United States Internal Revenue Service
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense

Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent.
MMBtu	Million British thermal units
Moody’s	Moody’s Investors Service, Inc.
MW	Megawatts
MWh	Megawatt-hours

Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
NGL	Natural Gas Liquids (1 barrel equals 6 Mcfe)
Northwest Wyoming Pool	Northwest Wyoming Natural Gas Pricing index
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
Panhandle Eastern Pipeline	Panhandle Eastern Pipeline Natural Gas Pricing Index
Peak View Wind Project	$109 million 60 MW wind generating project for Colorado Electric, adjacent to Busch Ranch wind farm
PPA	Power Purchase Agreement
Revolving Credit Facility	Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2021.
RMNG	Rocky Mountain Natural Gas, a regulated gas utility acquired in the SourceGas Acquisition that provides regulated transmission and wholesale natural gas service to Black Hills Gas in western Colorado (doing business as Black Hills Energy)
RSNs	Remarketable junior subordinated notes, issued on November 23, 2015
SEC	U. S. Securities and Exchange Commission
SourceGas	SourceGas Holdings LLC and its subsidiaries, a gas utility owned by funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co. (NYSE:GE) that was acquired on February 12, 2016, and is now named Black Hills Gas Holdings, LLC (doing business as Black Hills Energy)
SourceGas Acquisition	On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing.
S&P	Standard and Poor’s, a division of The McGraw-Hill Companies, Inc.
SSIR	System Safety and Integrity
TCA	Transmission Cost Adjustment -- adjustments passed through to the customer based on transmission costs that are higher or lower than the costs approved in the rate case.
VIE	Variable interest entity
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Wyodak Plant	Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, is owned 80% by Pacificorp and 20% by Black Hills Energy South Dakota. Our WRDC mine supplies all of the fuel for the plant.

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	(in thousands, except per share amounts)			
Revenue	$333,786	$272,105	$1,109,186	$986,346
Operating expenses:				
Fuel, purchased power and cost of natural gas sold	80,194	71,627	336,539	350,778
Operations and maintenance	115,103	89,830	334,706	273,374
Depreciation, depletion and amortization	48,925	37,768	140,637	116,821
Taxes - property, production and severance	12,114	10,675	36,991	33,988
Impairment of long-lived assets	12,293	61,875	52,286	178,395
Other operating expenses	6,748	2,374	40,730	3,392
Total operating expenses	275,377	274,149	941,889	956,748
Operating income (loss)	58,409	(2,044)	167,297	29,598
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(37,306)	(22,378)	(103,989)	(61,833)
Allowance for funds used during construction - borrowed	860	478	2,115	843
Capitalized interest	282	280	785	1,037
Interest income	912	414	2,513	1,163
Allowance for funds used during construction - equity	1,211	430	2,900	563
Other income (expense), net	160	842	801	1,568
Total other income (expense), net	(33,881)	(19,934)	(94,875)	(56,659)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	24,528	(21,978)	72,422	(27,061)
Equity in earnings (loss) of unconsolidated subsidiaries	—	—	—	(344)
Impairment of equity investments	—	—	—	(5,170)
Income tax benefit (expense)	(6,644)	12,035	(11,205)	14,640
Net income (loss)	17,884	(9,943)	61,217	(17,935)
Net income attributable to noncontrolling interest	(3,753)	—	(6,415)	—
Net income (loss) available for common stock	$14,131	$(9,943)	$54,802	$(17,935)
Earnings (loss) per share of common stock:				
Earnings (loss) per share, Basic	$0.27	$(0.22)	$1.06	$(0.40)
Earnings (loss) per share, Diluted	$0.26	$(0.22)	$1.04	$(0.40)
Weighted average common shares outstanding:				
Basic	52,184	44,635	51,583	44,598
Diluted	53,733	44,635	52,893	44,598

Dividends declared per share of common stock	$0.420	$0.405	$1.260	$1.215

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
	(in thousands)			
Net income (loss)	$17,884	$(9,943)	$61,217	$(17,935)
Other comprehensive income (loss), net of tax:				
Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of $(260) and $(1,609) for the three months ended 2016 and 2015 and $10,605 and $(1,482) for the nine months ended 2016 and 2015, respectively)	(551)	2,773	(20,617)	2,644
Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $566 and $558 for the three months ended 2016 and 2015 and $2,450 and $2,548 for the nine months ended 2016 and 2015, respectively)	(923)	(948)	(4,137)	(3,450)
Benefit plan liability adjustments - net gain (loss) (net of tax (expense) benefit of $0 and $0 for the three months ended 2016 and 2015 and $0 and $16 for the nine months ended 2016 and 2015, respectively)	—	—	—	(27)
Reclassification adjustments of benefit plan liability - prior service cost (net of tax (expense) benefit of $19 and $19 for the three months ended 2016 and 2015 and $58 and $58 for the nine months ended 2016 and 2015, respectively)	(36)	(36)	(108)	(108)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(171) and $(247) for the three months ended 2016 and 2015 and $(516) and $(742) for the nine months ended 2016 and 2015, respectively)	323	459	966	1,374
Other comprehensive income (loss), net of tax	(1,187)	2,248	(23,896)	433
Comprehensive income (loss)	16,697	(7,695)	37,321	(17,502)
Less: comprehensive income attributable to noncontrolling interest	(3,753)	—	(6,415)	—
Comprehensive income (loss) available for common stock	$12,944	$(7,695)	$30,906	$(17,502)

See Note 16 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, 2016	December 31, 2015	September 30, 2015
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$62,964	$456,535	$ 38,841
Restricted cash and equivalents	2,140	1,697	2,462
Accounts receivable, net	154,617	147,486	115,502
Materials, supplies and fuel	113,475	86,943	90,349
Derivative assets, current	4,382	—	—
Income tax receivable, net	—	368	—
Deferred income tax assets, net, current	—	—	47,783
Regulatory assets, current	50,561	57,359	51,962
Other current assets	30,032	71,763	55,383
Total current assets	418,171	822,151	402,282
Investments	12,416	11,985	12,148
Property, plant and equipment	6,306,119	4,976,778	4,882,420
Less: accumulated depreciation and depletion	(1,841,116)	(1,717,684)	(1,617,723)
Total property, plant and equipment, net	4,465,003	3,259,094	3,264,697
Other assets:			
Goodwill	1,300,379	359,759	359,527
Intangible assets, net	8,944	3,380	3,440
Regulatory assets, non-current	234,240	175,125	182,337
Derivative assets, non-current	183	3,441	—
Other assets, non-current	12,800	7,382	7,501
Total other assets, non-current	1,556,546	549,087	552,805
TOTAL ASSETS	$6,452,136	$4,642,317	$ 4,231,932

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, 2016	December 31, 2015	September 30, 2015
	(in thousands, except share amounts)		
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY			
Current liabilities:			
Accounts payable	$141,780	$105,468	$91,633
Accrued liabilities	228,522	232,061	229,889
Derivative liabilities, current	1,941	2,835	3,312
Accrued income taxes, net	10,909	—	308
Regulatory liabilities, current	16,925	4,865	5,647
Notes payable	75,000	76,800	117,900
Current maturities of long-term debt	5,743	—	—
Total current liabilities	480,820	422,029	448,689
Long-term debt	3,211,768	1,853,682	1,553,167
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	533,865	450,579	494,834
Derivative liabilities, non-current	317	156	722
Regulatory liabilities, non-current	186,496	148,176	152,164
Benefit plan liabilities	171,633	146,459	158,682
Other deferred credits and other liabilities	141,007	155,369	136,462
Total deferred credits and other liabilities	1,033,318	900,739	942,864
Commitments and contingencies (See Notes 10, 11, 12, 18, 19)			
Redeemable noncontrolling interest	4,206	—	—
Equity:			
Stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 53,131,469; 51,231,861; and 44,891,626 shares, respectively	53,131	51,232	44,892
Additional paid-in capital	1,123,527	953,044	753,856
Retained earnings	462,090	472,534	504,864
Treasury stock, at cost – 22,368; 39,720; and 36,711 shares, respectively	(1,155)	(1,888)	(1,789)
Accumulated other comprehensive income (loss)	(32,951)	(9,055)	(14,611)
Total stockholders' equity	1,604,642	1,465,867	1,287,212
Noncontrolling interest	117,382	—	—
Total equity	1,722,024	1,465,867	1,287,212
TOTAL LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY	$6,452,136	$4,642,317	$4,231,932

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,	
	2016	2015
Operating activities:	(in thousands)	
Net income (loss) available for common stock	$54,802	$(17,935)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	140,637	116,821
Deferred financing cost amortization	4,002	3,074
Impairment of long-lived assets	52,286	183,565
Derivative fair value adjustments	(7,308)	(8,851)
Stock compensation	9,124	2,868
Deferred income taxes	38,578	(20,808)
Employee benefit plans	11,830	15,175
Other adjustments, net	(2,076)	4,013
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	(5,166)	3,618
Accounts receivable, unbilled revenues and other operating assets	78,869	75,966
Accounts payable and other operating liabilities	(102,155)	(5,255)
Regulatory assets - current	8,453	27,768
Regulatory liabilities - current	(8,181)	2,457
Contributions to defined benefit pension plans	(14,200)	(10,200)
Interest rate swap settlement	(28,820)	—
Other operating activities, net	(5,998)	(6,403)
Net cash provided by (used in) operating activities	224,677	365,873
Investing activities:		
Property, plant and equipment additions	(334,098)	(349,471)
Acquisition, net of long term debt assumed	(1,124,238)	—
Other investing activities	(860)	(7,189)
Net cash provided by (used in) investing activities	(1,459,196)	(356,660)
Financing activities:		
Dividends paid on common stock	(65,247)	(54,450)
Common stock issued	107,690	2,484
Sale of noncontrolling interest	216,370	—
Short-term borrowings - issuances	208,100	287,910
Short-term borrowings - repayments	(209,900)	(245,010)
Long-term debt - issuances	1,767,608	300,000
Long-term debt - repayments	(1,162,872)	(275,000)
Distributions to noncontrolling interest	(4,516)	—
Other financing activities	(16,285)	(7,524)
Net cash provided by (used in) financing activities	840,948	8,410
Net change in cash and cash equivalents	(393,571)	17,623
Cash and cash equivalents, beginning of period	456,535	21,218
Cash and cash equivalents, end of period	$62,964	$38,841

See Note 17 for supplemental disclosure of cash flow information.

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

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2015 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 2015 Annual Report on Form 10-K filed with the SEC.

Segment Reporting

We conduct our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation, Mining and Oil and Gas. Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States. Prior to March 31, 2016, our segments were reported within two business groups, our Utilities Group, containing the Electric Utilities and Gas Utilities segments, and our Non-regulated Energy Group, containing the Power Generation, Coal Mining and Oil and Gas segments. We have continued to report our operations consistently through our reportable segments; however we will no longer separate the segments by business group.
We are a customer-focused, growth-oriented, vertically-integrated utility company. All of our non-utility business segments support our electric utilities, other than the Oil and Gas segment. In our oil and gas business, we are divesting non-core assets while retaining those best suited for a cost of service gas program and we have refocused our professional staff on assisting our utilities with the implementation of a cost of service gas program.
The following changes have been made to our Condensed Consolidated Statements of Income (Loss) to reflect combined operations and maintenance expenses, rather than by business group as previously reported, for the three and nine months ended September 30, 2015, respectively:

	For the Three Months Ended September 30, 2015			For the Nine Months Ended September 30, 2015		
(in thousands)	As Previously Reported	Presentation Reclassification	As Currently Reported	As Previously Reported	Presentation Reclassification	As Currently Reported
Utilities - operations and maintenance	$67,282	$ (67,282)	$ —	$205,630	$ (205,630)	$—
Non-regulated energy operations and maintenance	$22,548	$ (22,548)	$ —	$67,744	$ (67,744)	$—
Operations and maintenance	$—	$ 89,830	$ 89,830	$—	$ 273,374	$273,374

This presentation reclassification did not impact our consolidated financial position, results of operations or cash flows.

Segment Reporting Transition of Cheyenne Light's Natural Gas Distribution

Effective January 1, 2016, the natural gas operations of Cheyenne Light have been included in our Gas Utilities Segment. Through December 31, 2015, Cheyenne Light's natural gas operations were included in our Electric Utilities Segment as these natural gas operations were consolidated within Cheyenne Light since its acquisition. This change is a result of our business segment reorganization to, among other things, integrate all regulated natural gas operations, including the SourceGas Acquisition, into our Gas Utilities Segment which is led by the Group Vice President, Natural Gas Utilities. Likewise, all regulated electric utility operations, including Cheyenne Light's electric utility operations, are reported in our Electric Utilities Segment, which is led by the Group Vice President, Electric Utilities. The prior period has been reclassified to reflect this change in presentation between the Electric Utilities and Gas Utilities segments. See Note 3 for Revenues, Net Income and Segment Assets reclassified from the Electric Utilities segment to the Gas Utilities segment for the three and nine months ending September 30, 2015. This segment reclassification did not impact our consolidated financial position, results of operations or cash flows.

Use of Estimates and Basis of Presentation

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying Condensed Consolidated Financial Statements reflects all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the September 30, 2016, December 31, 2015, and September 30, 2015 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, 2016 and September 30, 2015, and our financial condition as of September 30, 2016, December 31, 2015, and September 30, 2015, 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.

Significant Accounting Policies

Business Combinations

We record acquisitions in accordance with ASC 805, Business Combinations, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. The excess of the purchase price over the estimated fair values of the net tangible and net intangible assets acquired is recorded as goodwill. The application of ASC 805, Business Combinations requires management to make significant estimates and assumptions in the determination of the fair value of assets acquired and liabilities assumed in order to properly allocate purchase price consideration between goodwill and assets that are depreciated and amortized. Our estimates are based on historical experience, information obtained from the management of the acquired companies and, when appropriate, include assistance from independent third-party appraisal firms. These estimates are inherently uncertain and unpredictable. In addition, unanticipated events or circumstances may occur which may affect the accuracy or validity of such estimates. See Note 2 for additional detail on the accounting for our acquisition.

Noncontrolling Interest

We account for changes in our controlling interests of subsidiaries according to ASC 810, Consolidations. ASC 810 requires that the Company record such changes as equity transactions, recording no gain or loss on such a sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company’s balance sheet. In addition, the amounts attributable to the noncontrolling interest net income (loss) of those subsidiaries are reported separately in the consolidated statements of income and comprehensive income. See Note 12 for additional detail on Noncontrolling Interests.

Share-Based Compensation

We account for our share-based compensation arrangements in accordance with ASC 718, Compensation-Stock Compensation, by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. Awards that will be settled in stock are accounted for as equity and the compensation expense is based on the grant date fair value. Awards that are settled in cash are accounted for as liabilities and the compensation expense is re-measured each period based on the current market price and performance achievement measures.

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Recently Issued and Adopted Accounting Standards

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

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

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

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting. This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early adoption permitted. Certain amendments of this guidance are to be applied retrospectively and others prospectively. We are currently assessing the impact that adoption of ASU 2016-09 will have on our consolidated financial position, results of operations and cash flows.

Leases, ASU 2016-02

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which supersedes ASC 840, Leases. This ASU requires lessees to recognize a right-of-use asset and lease liability for all leases with terms of more than 12 months. Lessees are permitted to make an accounting policy election to not recognize the asset and liability for leases with a term of 12 months or less. 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 ASC is largely unchanged from the previous accounting standard. In addition, the ASU expands the disclosure requirements of lease arrangements. Lessees and lessors will use a modified retrospective transition approach, which includes a number of practical expedients. The guidance is effective for the Company beginning after December 15, 2018. Early adoption is permitted. We are currently assessing the impact that adoption of ASU 2016-02 will have on our financial position, results of operations and cash flows.

Revenue from Contracts with Customers, ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The standard provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. On July 9, 2015, FASB voted to defer the effective date of ASU 2014-09 by one year. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017 and early adoption is permitted. Entities will have the option of using either a full retrospective or modified retrospective approach to adopting this guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption. As of September 30, 2016, we were actively evaluating all of our sources of revenue to determine the impact that adoption of ASU 2014-09 will have on our financial position, results of operations and cash flows.

Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent), ASU 2015-07

On May 1, 2015, the FASB issued ASU 2015-07, Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent). The ASU removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient and also removes certain disclosure requirements. The new requirements were effective for us beginning January 1, 2016 and will be applied retrospectively to all periods presented, in our 2016 Form 10-K. This ASU will not materially affect our financial statements and disclosures, but will change certain presentation and disclosure of the fair value of certain plan assets in our pension and other postretirement benefit plan disclosures in our 2016 Form 10-K, for all periods presented.

Simplifying the Presentation of Debt Issuance Costs, ASU 2015-03

In April 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. Debt issuance costs related to a recognized debt liability are presented on the balance sheet as a direct deduction from the debt liability, similar to the presentation of debt discounts, rather than as an asset. Amortization of these costs will continue to be reported as interest expense. ASU 2015-03 is effective for annual and interim reporting periods beginning after December 15, 2015. We adopted ASU 2015-03 in the first quarter of 2016 on a retrospective basis. As of September 30, 2016, we presented the debt issuance costs, previously reported in other assets, as direct deductions from the carrying amount of long-term debt. The implementation of this standard resulted in reductions of other assets, non-current and long-term debt of $13 million and $15 million in the Condensed Consolidated Balance Sheets as of December 31, 2015, and September 30, 2015, respectively. Adoption of ASU 2015-03 did not have a material impact on our financial position.

Simplifying the Accounting for Measurement-Period Adjustments, ASU 2015-16

In September 2015, the FASB issued ASU 2015-16, Simplifying the Accounting for Measurement-Period Adjustments. This ASU eliminates the requirement to retrospectively account for changes to provisional amounts recognized at the acquisition date in a business combination. ASU 2015-16 requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustments are determined, including the effect of the change in the provisional amount as if the accounting had been completed at the acquisition date. The provisions of this ASU are effective for fiscal years beginning after December 31, 2015, including interim periods within those fiscal years and should be applied prospectively to adjustments to provisional amounts that occur after the effective date. We have implemented ASU 2015-16 as of January 1, 2016. Adoption of this standard did not have a material impact on our financial position, results of operations and cash flows.

(2) ACQUISITION

Acquisition of SourceGas

On February 12, 2016, Black Hills Corporation acquired SourceGas, pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, including the assumption of $760 million in debt at closing. The purchase price was subject to post-closing adjustments for capital expenditures, indebtedness and working capital. Post-closing adjustments of approximately $11 million were agreed to and received from the sellers in June 2016. SourceGas is a 99.5% owned subsidiary of Black Hills Utility Holdings, Inc., a wholly-owned subsidiary of Black Hills Corporation and has been renamed Black Hills Gas Holdings, LLC. Black Hills Gas Holdings primarily operates four regulated natural gas utilities serving approximately 429,000 customers in Arkansas, Colorado, Nebraska and Wyoming, and a 512-mile regulated intrastate natural gas transmission pipeline in Colorado.

Cash consideration of $1.135 billion paid on February 12, 2016 to close the SourceGas Acquisition included net proceeds of approximately $536 million from the November 23, 2015 issuance of 6.325 million shares of our common stock and 5.98 million equity units, and $546 million in net proceeds from our debt offerings on January 13, 2016. We funded the cash consideration and out-of-pocket expenses payable with the SourceGas Acquisition using the proceeds listed above, cash on hand, and draws under our revolving credit facility.

In connection with the acquisition, the Company recorded pre-tax, incremental acquisition costs of approximately $5.2 million and $36 million, respectively, in the three and nine months ended September 30, 2016. These costs consisted of transaction costs, professional fees, employee-related expenses and other miscellaneous costs. The costs are recorded primarily in Other operating expenses on the Condensed Consolidating Income Statements. There were $4.3

million and $5.0 million of incremental acquisition costs recorded in the three and nine months ended September 30, 2015, respectively.

Our consolidated operating results for the three and nine months ended September 30, 2016 include revenues of $72 million and $217 million, respectively, and net income (loss) of $(3.8) million and $0.8 million, respectively, attributable to SourceGas for the period from February 12 through September 30, 2016. The SourceGas operating results are reported in our Gas Utilities segment. We believe the SourceGas Acquisition enhances Black Hills Corporation's utility growth strategy, providing greater operating scale, driving more efficient delivery of services and benefiting customers.

We accounted for the SourceGas Acquisition in accordance with ASC 805, Business Combinations, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. Substantially all of SourceGas' operations are subject to the rate-setting authority of state regulatory commissions, and are accounted for in accordance with GAAP for regulated operations. SourceGas' assets and liabilities subject to rate setting provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair value of these assets and liabilities equal their historical net book values.

We are still determining the purchase price allocation for SourceGas. A preliminary purchase price allocation of the fair value of the assets acquired and liabilities assumed is included in the table below. The cash consideration paid of $1.124 billion, net of long-term debt assumed of $760 million and a working capital adjustment received of approximately $11 million, resulted in a preliminary estimate of goodwill totaling $941 million. This estimate is subject to change and will likely result in an increase or decrease in goodwill, which could be material. We have up to one year from the acquisition date to finalize the purchase price allocation. From the time of acquisition through September 30, 2016, we decreased goodwill by $5.8 million, reflecting the working capital adjustment received of $11 million and changes in valuation estimates for long-term debt, intangible assets, accrued liabilities and deferred taxes. Approximately $251 million of the goodwill balance is amortizable for tax purposes, relating to the partnership interests that were directly acquired in the transaction. The remainder of the goodwill balance is not amortizable for tax purposes. Goodwill generated from the acquisition reflects the benefits of increased operating scale and organic growth opportunities.

	(in thousands)
Preliminary Purchase Price	$1,894,882
Less: Long-term debt assumed	(760,000)
Less: Working capital adjustment received	(10,644)
Consideration Paid, net of working capital adjustment received	$1,124,238
Preliminary Allocation of Purchase Price:	
Current Assets	$111,893
Property, plant & equipment, net	1,058,093
Goodwill	940,620
Deferred charges and other assets, excluding goodwill	133,215
Current liabilities	(166,807)
Long-term debt	(764,337)
Deferred credits and other liabilities	(188,439)
Total preliminary consideration paid, net of working-capital adjustment received	$1,124,238

Conditions of SourceGas Acquisition Regulatory Approval

The acquisition was subject to regulatory approvals from the public utility commissions in Arkansas (APSC), Colorado (CPUC), Nebraska (NPSC), and Wyoming (WPSC). Approvals were obtained from all commissions, subject to various conditions as set forth below:

The APSC order includes a 12 month base rate moratorium, an annual $0.25 million customer credit for a term of up to five-years or until we file the next rate case, whichever comes first, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate case, as well as various other terms and reporting requirements.

The CPUC order includes a two-year base rate moratorium for our regulated transmission and wholesale natural gas provider, a three-year base rate moratorium for our regulated gas distribution utility, an annual $0.2 million customer credit for a term of up to five-years or until we file the next rate case, whichever comes first, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate case, as well as various other terms and reporting requirements.

The NPSC order includes a three-year base rate moratorium, a three-year continuation of the Choice Gas program, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate case, as well as various other terms and reporting requirements.

The WPSC order includes a three-year continuation of the Choice Gas program, as well as various other terms and reporting requirements.

All four orders also disallowed recovery of goodwill and transaction costs. Recovery of transition costs is disallowed in Arkansas, Colorado and Nebraska, however Wyoming allows for request of recovery of transition costs. Transition costs are those non-recurring costs related to the transition and integration of SourceGas. In the conditions mentioned above, the orders that include base rate moratoriums over a specified period of time do not impact our ability to adjust rates through riders or gas supply cost recovery mechanisms as allowed under the current enacted state tariffs. In certain cases, we may file for leave to increase general base rates and/or cost of sales recovery limited to material adverse changes, but only if there are changes in law or regulations or the occurrence of other extraordinary events outside of our control which result in a material adverse change in revenues, revenue requirement and/or increase in operating costs.

Settlement of Gas Supply Contract

On April 29, 2016, we settled for $40 million, a former SourceGas contract that required the company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. This contract’s intangible negative fair value is included with Current liabilities of the preliminary purchase price allocation. Approximately 75% of these purchases were committed to distribution customers in Nebraska, Colorado and Wyoming, which are subject to cost recovery mechanisms, while the remaining 25% was not subject to regulatory recovery. The prices to be paid under this contract varied, ranging from $6 to $8 per MMBtu at the time of acquisition and exceeded market prices. We applied for and were granted approval to terminate this agreement from the NPSC, CPUC and WPSC, on the basis that the agreement was not beneficial to customers in the long term. We received written orders allowing recovery of the net buyout costs associated with the contract termination that were allocated to regulated subsidiaries. These costs were recorded as a regulatory asset of approximately $30 million that is being recovered over a five-year period.

Pro Forma Results

We calculated the pro forma impact of the SourceGas Acquisition and the associated debt and equity financings on our operating results for the three and nine months ended September 30, 2016 and 2015. The following pro forma results give effect to the acquisition, assuming the transaction closed on January 1, 2015:

	Pro Forma Results Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands, except per share amounts)			
Revenue	$333,786	$344,498	$1,188,148	$1,320,047
Net income (loss) available for common stock	$17,376	$(14,189)	$89,973	$(13,884)
Earnings (loss) per share, Basic	$0.33	$(0.28)	$1.74	$(0.27)
Earnings (loss) per share, Diluted	$0.32	$(0.28)	$1.70	$(0.27)

We derived the pro forma results for the SourceGas Acquisition based on historical financial information obtained from the sellers and certain management assumptions. Our pro forma adjustments relate to incremental interest expense associated with the financings to effect the transaction, and for the three and nine months ended September 30, 2015, also include adjustments to shares outstanding to reflect the equity issuances as if they had occurred on January 1, 2015, and to reflect pro forma dilutive effects of the equity units issued. The pro forma results do not reflect any cost savings, (or associated costs to achieve such savings) from operating efficiencies or restructuring that could result from the acquisition, and exclude any unique one-time items resulting from the acquisition that are not expected to have a continuing impact on the combined consolidated results. Pro forma results for the three and nine months ended September 30, 2016 reflect unfavorable weather impacts resulting in lower gas usage by our customers than in the same periods of the prior year. In addition, we calculated the tax impact of these adjustments at an estimated combined federal and state income tax rate of 37%.

These pro forma results are for illustrative purposes only and do not purport to be indicative of the results that would have been obtained had the SourceGas Acquisition been completed on January 1, 2015, or that may be obtained in the future.

Seller's noncontrolling interest

One of the sellers retained 0.5% of the outstanding equity interests of SourceGas under the terms of the purchase agreement. As part of the transaction, we entered into an associated option agreement with that holder of the retained interest. The terms of this agreement provide us a call option to purchase the remaining interest beginning 366 days after the initial close of the SourceGas transaction. If we choose not to exercise this option during a ninety-day period, the seller may exercise the put option to sell us the retained interest. The value of this 0.5% equity interest is shown as Redeemable noncontrolling interest on the accompanying condensed consolidated balance sheets.

(3) BUSINESS SEGMENT INFORMATION

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

Three Months Ended September 30, 2016	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$171,754	$ 2,747	$24,181
Gas [f]	141,445	—	(2,939)
Power Generation [e]	1,906	21,431	5,642
Mining	9,042	7,778	3,307
Oil and Gas [a]	9,639	—	(8,828)
Corporate activities [c]	—	—	(7,232)
Inter-company eliminations	—	(31,956)	—
Total	$333,786	$ —	$14,131

Three Months Ended September 30, 2015	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric [d]	$176,042	$ 2,548	$22,659
Gas [d]	75,155	—	652
Power Generation	2,123	21,128	9,067
Mining	8,890	8,076	3,047
Oil and Gas [a] [b]	9,895	—	(39,769)
Corporate activities [c]	—	—	(5,599)
Inter-company eliminations	—	(31,752)	—
Total	$272,105	$ —	$(9,943)

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Nine Months Ended September 30, 2016	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$493,845	$ 9,413	$62,625
Gas [f]	563,879	—	29,975
Power Generation [e]	5,304	63,055	19,907
Mining	20,498	23,651	6,969
Oil and Gas [a]	25,660	—	(35,277)
Corporate activities [c]	—	—	(29,397)
Inter-company eliminations	—	(96,119)	—
Total	$1,109,186	$ —	$54,802

Nine Months Ended September 30, 2015	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric [d]	$504,049	$ 8,481	$57,844
Gas [d]	416,950	—	27,475
Power Generation	5,782	62,452	24,761
Mining	26,084	23,541	9,106
Oil and Gas [a] [b]	33,481	—	(130,079)
Corporate activities [c]	—	—	(7,042)
Inter-company eliminations	—	(94,474)	—
Total	$986,346	$ —	$(17,935)

(a) Net income (loss) available for common stock for the three and nine months ended September 30, 2016 and September 30, 2015 includes non-cash after-tax impairments of oil and gas properties of $7.9 million and $33 million and $36 million and $113 million, respectively. See Note 20 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b) Net income (loss) available for common stock for the nine months ended September 30, 2015 included a non-cash after-tax impairment to equity investments of $3.4 million. See Note 20 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(c) Net income (loss) available for common stock for the three and nine months ended September 30, 2016 and September 30, 2015 included incremental, non-recurring acquisition costs, net of tax of $4.0 million and $24 million; and $2.8 million and $3.0 million respectively, and after-tax internal labor costs attributable to the acquisition of $1.7 million and $7.4 million; and $1.2 million and $1.8 million respectively. See Note 2 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(d) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utility segment. Cheyenne Light's gas utility results for the three and nine months ended September 30, 2015 have been reclassified from the Electric Utility segment to the Gas Utility segment. Revenue of $6.2 million and $31 million, respectively, and Net loss of $1.0 million and Net income of $0.5 million, respectively, previously reported in the Electric Utility segment in 2015 are now included in the Gas Utility segment.

(e) Net income (loss) available for common stock is net of net income attributable to noncontrolling interests of $3.8 million and $6.4 million for the three and nine months ended September 30, 2016.

(f) Gas Utility revenue increased for the three and nine months ended September 30, 2016 compared to the same periods in the prior year primarily due to the addition of the SourceGas utilities on February 12, 2016.

Segment information and Corporate balances included in the accompanying Condensed Consolidated Balance Sheets were as follows (in thousands):

Total Assets (net of inter-company eliminations) as of:	September 30, 2016	December 31, 2015	September 30, 2015
Segment:			
Electric [(a) (b)]	$2,824,145	$2,720,004	$2,706,654
Gas [(b) (e)]	3,182,852	999,778	967,225
Power Generation [(a)]	77,570	60,864	78,666
Mining	66,804	76,357	78,000
Oil and Gas [(c)]	158,970	208,956	280,842
Corporate activities [(d)]	141,795	576,358	120,545
Total assets	$6,452,136	$4,642,317	$4,231,932

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

(b) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utility segment. Cheyenne Light's gas utility assets as of the nine months ended September 30, 2015 have been reclassified from the Electric Utility segment to the Gas Utility segment. Assets of $135 million and $136 million, respectively, previously reported in the Electric Utility segment in 2015 are now presented in the Gas Utility segment as of December 31, 2015 and September 30, 2015.

(c) As a result of continued low commodity prices and our decision to divest non-core oil and gas assets, we recorded non-cash impairments of $52 million for the nine months ended September 30, 2016, $250 million for the year ended December 31, 2015, and $178 million for the nine months ended September 30, 2015. See Note 20 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(d) Corporate assets at December 31, 2015 included approximately $440 million of cash from the November 23, 2015 equity offerings, which was used to partially fund the SourceGas acquisition on February 12, 2016.

(e) Includes the assets acquired in the SourceGas acquisition on February 12, 2016.

(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, 2016	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 44,747	$ 30,970	$ (580)	$ 75,137
Gas Utilities	48,057	23,582	(1,923)	69,716
Power Generation	1,165	—	—	1,165
Mining	3,612	—	—	3,612
Oil and Gas	3,341	—	(13)	3,328
Corporate	1,659	—	—	1,659
Total	$ 102,581	$ 54,552	$ (2,516)	$ 154,617

	Accounts	Unbilled	Less Allowance	Accounts

December 31, 2015	Receivable, Trade	Revenue	for Doubtful Accounts	Receivable, net
Electric Utilities [(a)]	$ 41,679	$ 35,874	$ (727)	$ 76,826
Gas Utilities [(a)]	30,331	32,869	(1,001)	62,199
Power Generation	1,187	—	—	1,187
Mining	2,760	—	—	2,760
Oil and Gas	3,502	—	(13)	3,489
Corporate	1,025	—	—	1,025
Total	$ 80,484	$ 68,743	$ (1,741)	$ 147,486

September 30, 2015	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities [(a)]	$ 41,655	$ 33,979	$ (811)	$ 74,823
Gas Utilities [(a)]	20,031	11,230	(527)	30,734
Power Generation	1,186	—	—	1,186
Mining	2,684	—	—	2,684
Oil and Gas	4,522	—	(13)	4,509
Corporate	1,566	—	—	1,566
Total	$ 71,644	$ 45,209	$ (1,351)	$ 115,502

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(a) Effective January 1, 2016, Cheyenne Light’s natural gas utility results are reported in our Gas Utility segment. Cheyenne Light’s gas utility accounts receivable has been reclassified from the Electric Utility segment to the Gas Utility segment. Accounts receivable of $6.8 million and $2.9 million as of December 31, 2015 and September 30, 2015, respectively, previously reported in the Electric Utility segment is now presented in the Gas Utility segment.

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(5) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of September 30, 2016	As of December 31, 2015	As of September 30, 2015
Regulatory assets				
Deferred energy and fuel cost adjustments - current [a] [d]	1	$ 16,525	$ 24,751	$ 25,354
Deferred gas cost adjustments [a][d]	1	12,172	15,521	9,358
Gas price derivatives [a]	7	14,405	23,583	23,681
AFUDC [b]	45	14,093	12,870	12,580
Employee benefit plans [c] [e]	12	107,578	83,986	95,779
Environmental [a]	subject to approval	1,126	1,180	1,209
Asset retirement obligations [a]	44	507	457	675
Loss on reacquired debt [a]	30	15,918	3,133	3,169
Renewable energy standard adjustment [b]	5	1,694	5,068	5,102
Flow through accounting [c]	35	33,136	29,722	28,585
Decommissioning costs [f]	10	17,271	18,310	16,353
Gas supply contract termination	5	28,164	—	—
Other regulatory assets [a]	15	22,212	13,903	12,454
		$ 284,801	$ 232,484	$ 234,299
Regulatory liabilities				
Deferred energy and gas costs [a] [d]	1	$ 15,033	$ 7,814	$ 9,899
Employee benefit plans [c] [e]	12	65,575	47,218	53,140
Cost of removal [a]	44	114,616	90,045	86,946
Other regulatory liabilities [c]	25	8,197	7,964	7,826
		$ 203,421	$ 153,041	$ 157,811

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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) Our deferred energy, fuel cost, and gas cost adjustments represent the cost of electricity and gas delivered to our electric and gas utility customers that is either higher or lower than current rates and will be recovered or refunded in future rates. Our electric and gas utilities file periodic quarterly, semi-annual, and/or annual filings to recover these costs based on the respective cost mechanisms approved by their applicable state utility commissions.

(e) Increase compared to December 31, 2015 was driven by addition of the SourceGas employee benefit plans.

(f) South Dakota Electric has approximately $12 million of decommissioning costs associated with the retirements of the Neil Simpson I and Ben French power plants that are allowed a rate of return, in addition to recovery of costs.

Loss on reacquired debt - The increase from the prior periods is the loss on the early retirement of debt assumed in the SourceGas Acquisition. These costs are being amortized to interest expense over a maximum period of 30 years.

Gas Supply Contract Termination - Black Hills Gas Holdings had agreements under the previous ownership that required the company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. The majority of these purchases were committed to distribution customers in Nebraska, Colorado, and Wyoming, which are subject to cost recovery mechanisms. The prices to be paid under these agreements varied, ranging from $6 to $8 per MMBtu at the time of acquisition, and exceeded market prices. We recorded a liability for this contract in our purchase price allocation. We were granted approval to terminate these agreements from the NPSC, CPUC and WPSC, on the basis that these agreements are not beneficial to customers over the long term. We received written orders allowing us to create a regulatory asset for the net buyout costs associated with the contract termination, and recover the majority of costs from customers over a five year period. We terminated the contract and settled the liability on April 29, 2016.

Cost of Removal - Cost of Removal represents the estimated cumulative net provisions for future removal costs included in depreciation expense. The increase from the prior periods is primarily due to cost of removal recorded with the SourceGas purchase price allocation.

(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, 2016	December 31, 2015	September 30, 2015
Materials and supplies	$ 67,257	$ 55,726	$ 53,838
Fuel - Electric Utilities	4,282	5,567	6,139
Natural gas in storage held for distribution	41,936	25,650	30,372
Total materials, supplies and fuel	$ 113,475	$ 86,943	$ 90,349

(7) GOODWILL & INTANGIBLE ASSETS

Following is a summary of Goodwill included in the accompanying Condensed Consolidated Balance Sheets (in thousands):

	Electric Utilities (b)	Gas Utilities (b)	Power Generation	Total
Ending balance at December 31, 2015	$256,850	$94,144	$ 8,765	$359,759
Acquisition of SourceGas (a)	—	940,620	—	940,620
Ending balance at September 30, 2016	$256,850	$1,034,764	$ 8,765	$1,300,379

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(a) Represents preliminary goodwill recorded with the acquisition of SourceGas. See Note 2 for more information.

(b) Goodwill of $6.3 million is now presented in the Gas Utilities segment as a result of the inclusion of Cheyenne Light's Gas operations in the Gas Utility segment, previously reported in the Electric Utilities segment. See Note 1 for additional details.

Following is a summary of Intangible assets included in the accompanying Condensed Consolidated Balance Sheets (in thousands):

Intangible assets, net beginning balance at December 31, 2015	$3,380
Additions/amortization, net (a)	5,564
Intangible assets, net, ending balance at September 30, 2016	$8,944

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(a) Intangible assets, net acquired from SourceGas are primarily non-regulated customer relationships, and are amortized over their 10-year estimated useful lives. See Note 2 for more information.

(8) ASSET RETIREMENT OBLIGATIONS

The following table presents the details of asset retirement obligations which are included on the accompanying Condensed Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	December 31, 2015	Liabilities Incurred	Liabilities Settled	Accretion	Liabilities Acquired (a)	Revisions to Prior Estimates (b) (c)	September 30, 2016
Electric Utilities	$ 4,462	$ —	$ —	$ 143	$ —	$ 11	$ 4,616
Gas Utilities	136	—	—	478	22,412	6,436	29,462
Mining	18,633	—	(15)	653	—	(5,603)	13,668
Oil and Gas	21,504	—	(814)	1,047	—	57	21,794
Total	$ 44,735	$ —	$ (829)	$ 2,321	$ 22,412	$ 901	$ 69,540

(a) Represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations. Approximately $22 million was recorded with the purchase price allocation of SourceGas.

(b) The Gas Utilities Revision to Prior Estimates represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations.

(c) The Mining Revision to Prior Estimates reflects an approximately 33% reduction in equipment costs as promulgated by the State of Wyoming.

(9) EARNINGS PER SHARE

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net income (loss) available for common stock	$ 14,131	$ (9,943)	$ 54,802	$ (17,935)
Weighted average shares - basic	52,184	44,635	51,583	44,598
Dilutive effect of:				
Equity Units [(a)]	1,414	—	1,191	—
Equity compensation	135	—	119	—
Weighted average shares - diluted [(b)]	53,733	44,635	52,893	44,598

(a) Calculated using the treasury stock method.

(b) Due to our net loss for the three and nine months ended September 30, 2015, potentially dilutive securities were excluded from the diluted loss per share calculation due to their anti-dilutive effect. In computing dilutive net loss per share, 58,380 and 82,130 equity compensation shares were excluded from the computations for the three and nine months ended September 30, 2015, respectively.

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,	
	2016	2015	2016	2015
Equity compensation	2	121	4	114
Anti-dilutive shares	2	121	4	114

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(10) NOTES PAYABLE

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

	September 30, 2016		December 31, 2015		September 30, 2015	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$75,000	$30,500	$76,800	$33,399	$117,900	$30,600

Revolving Credit Facility

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extend the term through August 9, 2021 with two one-year extension options. This facility is similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase total commitments of the facility up to $1 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from either S&P or Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.125%, 1.125%, and 1.125%, respectively, at September 30, 2016. A 0.175% commitment fee is charged on the unused amount of the Revolving Credit Facility.

Debt Financial Covenants

On February 12, 2016, in connection with the SourceGas Acquisition discussed in Note 2, our Revolving Credit Facility and Term Loan credit agreements were amended to permit the assumption of certain indebtedness of SourceGas and to increase the Recourse Leverage Ratio. We also amended and restated SourceGas's $340 million term loan due June 30, 2017. On February 12, 2016, the maximum Recourse Leverage Ratio increased to 0.75 to 1.00 until March 31, 2017, a period of four fiscal quarters following the SourceGas acquisition; it was previously 0.65 to 1.00. On August 9, 2016, in conjunction with the amendment and restatement of the Revolving Credit Facility and Term Loan, the Recourse Leverage Ratio was amended and replaced with the Consolidated Indebtedness to Capitalization Ratio. Under the amended and restated Revolving Credit Facility and Term Loan, we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.70 to 1.00 at the end of fiscal quarters ending September 30, 2016 and December 31, 2016 and not to exceed 0.65 to 1.00 at the end of any fiscal quarter thereafter.

Except as provided above, our Revolving Credit Facility and our Term Loans require compliance with the following financial covenant at the end of each quarter:

	As of September 30, 2016	Covenant Requirement
Consolidated Indebtedness to Capitalization Ratio	68%	Less than 70%

As of September 30, 2016, we were in compliance with this covenant.

(11) LONG-TERM DEBT AND CURRENT MATURITIES OF LONG-TERM DEBT

Long-term debt was as follows (dollars in thousands):

	Interest Rate at September 30, 2016	September 30, 2016	December 31, 2015	September 30, 2015
Corporate				
Remarketable junior subordinated notes due November 1, 2028	3.50%	$299,000	$299,000	$—
Senior unsecured notes due January 15, 2026	3.95%	300,000	—	—
Unamortized discount on Senior unsecured notes due 2026		(842)	—	—
Senior unsecured notes due November 30, 2023	4.25%	525,000	525,000	525,000
Unamortized discount on Senior unsecured notes due 2023		(1,685)	(1,890)	(1,959)
Senior unsecured notes due July 15, 2020	5.88%	200,000	200,000	200,000
Senior unsecured notes due January 11, 2019	2.50%	250,000	—	—
Unamortized discount on Senior unsecured notes due 2019		(205)	—	—
Senior unsecured notes due January 15, 2027	3.15%	400,000	—	—
Unamortized discount on Senior unsecured notes due 2027		(202)	—	—
Senior unsecured notes, due September 15, 2046	4.20%	300,000	—	—
Unamortized discount on Senior unsecured notes due 2046		(1,630)	—	—
Corporate term loan due August 9, 2019 [a]	1.46%	400,000	—	—
Corporate term loan due April 12, 2017 [a]		—	300,000	300,000
Corporate term loan due June 7, 2021	2.32%	25,842	—	—
Total Corporate Debt		2,695,278	1,322,110	1,023,041
Electric Utilities				
First Mortgage Bonds due October 20, 2044	4.43%	85,000	85,000	85,000
First Mortgage Bonds due October 20, 2044	4.53%	75,000	75,000	75,000
First Mortgage Bonds due August 15, 2032	7.23%	75,000	75,000	75,000
First Mortgage Bonds due November 1, 2039	6.13%	180,000	180,000	180,000
Unamortized discount on First Mortgage Bonds due 2039		(96)	(99)	(99)
First Mortgage Bonds due November 20, 2037	6.67%	110,000	110,000	110,000
Industrial development revenue bonds due September 1, 2021 [b]	0.86%	7,000	7,000	7,000
Industrial development revenue bonds due March 1, 2027 [b]	0.86%	10,000	10,000	10,000
Series 94A Debt, variable rate due June 1, 2024 [b]	1.01%	2,855	2,855	2,855
Total Electric Utilities Debt		544,759	544,756	544,756
Total long-term debt		3,240,037	1,866,866	1,567,797
Less current maturities		5,743	—	—
Less deferred financing costs [c]		22,526	13,184	14,630
Long-term debt, net of current maturities		$3,211,768	$1,853,682	$1,553,167

(a) Variable interest rate, based on LIBOR plus a spread.

(b) Variable interest rate.

(c) Includes deferred financing costs associated with our Revolving Credit Facility of $2.5 million, $1.7 million and $1.9 million as of September 30, 2016, December 31, 2015 and September 30, 2015, respectively.

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Scheduled future maturities of debt, excluding amortization of premiums or discounts are (in thousands):

Year Ended:	
2016	$1,436
2017	$5,743
2018	$5,743
2019	$655,743
2020	$205,742
Thereafter	$2,370,290

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at September 30, 2016.

Current Maturities of Long-Term Debt

As of September 30, 2016, we have the following classified as Current maturities of long-term debt:

Loan	Interest Rate	Current Maturities at September 30, 2016
Corporate		
Corporate term loan due June 7, 2021 [(a)]	2.32%	5,743
Current Maturities of Long-Term Debt		$ 5,743

(a) Principal payments of $1.4 million are due quarterly.

Debt Transactions

On August 19, 2016, we completed a public debt offering of $700 million principal amount of senior unsecured notes. The debt offering consisted of $400 million of 3.15% ten-year senior notes due January 15, 2027 and $300 million of 4.20% 30-year senior notes due September 15, 2046 (together the “Notes”). The proceeds of the Notes were used for the following:

- Repay the $325 million 5.9% senior unsecured notes assumed in the SourceGas Acquisition;

- Repay the $95 million, 3.98% senior secured notes assumed in the SourceGas Acquisition;

- Repay the remaining $100 million on the $340 million unsecured term loan assumed in the SourceGas Acquisition;

- Pay down $100 million of the $500 million three-year unsecured term loan discussed below;

- Payment of $29 million for the settlement of $400 million notional interest rate swap; and

- Remainder was used for general corporate purposes.

On August 9, 2016, we entered into a $500 million, three-year, unsecured term loan expiring on August 9, 2019. The proceeds of this term loan was used to pay down $240 million of the $340 million unsecured term loan assumed in the

SourceGas Acquisition and the $260 million term loan expiring on April 12, 2017. This new term loan has substantially similar terms and covenants as the amended and restated Revolving Credit Facility.

In accordance with regulatory orders related to the early termination and settlement of the gas supply contract described in Note 5, on June 7, 2016, we entered into a 2.32%, $29 million term loan, due June 7, 2021. Proceeds from this term loan were used to finance the early termination of the gas supply contract, resulting in a regulatory asset. Principal and interest are payable quarterly at approximately $1.6 million, the first of which were paid on June 30, 2016.

On January 13, 2016, we completed a public debt offering of $550 million principal amount of senior unsecured notes. The debt offering consisted of $300 million of 3.95%, ten-year senior notes due 2026, and $250 million of 2.50%, three-year senior notes due 2019. After discounts and underwriter fees, net proceeds from the offering totaled $546 million and were used as funding for the SourceGas Acquisition. The discounts are amortized over the life of each respective note.

Assumption of Long-Term Debt

At the closing of the SourceGas Acquisition on February 12, 2016, we assumed $760 million in long-term debt, consisting of the following:

- $325 million, 5.9% senior unsecured notes with an original issue date of April 16, 2007, due April 1, 2017.
- $95 million, 3.98% senior secured notes with an original issue date of September 29, 2014, due September 29, 2019.
- $340 million unsecured corporate term loan due June 30, 2017. Interest under this term loan was LIBOR plus a margin of 0.875%.

As of September 30, 2016, the $760 million in long-term debt assumed in the SourceGas Acquisition was repaid.

(12) EQUITY

A summary of the changes in equity is as follows:

Nine Months Ended September 30, 2016	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
		(in thousands)	
Balance at December 31, 2015	$ 1,465,867	$ —	$ 1,465,867
Net income (loss)	54,802	6,402	61,204
Other comprehensive income (loss)	(23,896)	—	(23,896)
Dividends on common stock	(65,247)	—	(65,247)
Share-based compensation	3,822	—	3,822
Issuance of common stock	105,238	—	105,238
Dividend reinvestment and stock purchase plan	2,242	—	2,242
Other stock transactions	(24)	—	(24)
Sale of noncontrolling interest	61,838	115,496	177,334
Distribution to noncontrolling interest	—	(4,516)	$ (4,516)
Balance at September 30, 2016	$ 1,604,642	$ 117,382	$ 1,722,024

Nine Months Ended September 30, 2015	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
		(in thousands)	
Balance at December 31, 2014	$ 1,353,884	$ —	$ 1,353,884
Net income (loss)	(17,935)	—	(17,935)
Other comprehensive income (loss)	433	—	433
Dividends on common stock	(54,450)	—	(54,450)
Share-based compensation	2,998	—	2,998

Issuance of common stock	—	—	—
Dividend reinvestment and stock purchase plan	2,298	—	2,298
Other stock transactions	(16)	—	(16)
Balance at September 30, 2015	$ 1,287,212	$ —	$ 1,287,212

At-the-Market Equity Offering Program

On March 18, 2016, we implemented an ATM equity offering program allowing us to sell shares of our common stock with an aggregate value of up to $200 million. The shares may be offered from time to time pursuant to a sales agreement dated March 18, 2016. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. During the three months ended September 30, 2016, we issued 819,442 common shares for $49 million, net of $0.5 million in commissions under the ATM equity offering program. Through September 30, 2016, we have sold and issued an aggregate of 1,750,091 shares of common stock under the ATM equity offering program for $106 million, net of $1.1 million in commissions. Additionally, 38,781 shares for net proceeds of $2.4 million have been sold, but were not settled and are not considered issued and outstanding as of September 30, 2016.

Sale of Noncontrolling Interest in Subsidiary

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

ASC 810 requires the accounting for a partial sale of a subsidiary in which control is maintained and the subsidiary continues to be consolidated. The partial sale is required to be recorded as an equity transaction with no resulting gain or loss on the sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company’s balance sheet. Distributions of net income attributable to noncontrolling interests are due within 30 days following the end of a quarter, but may be withheld as necessary by Black Hills Electric Generation.

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

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

	September 30, 2016	December 31, 2015	September 30, 2015
	(in thousands)		
Assets			
Current assets	$14,191	$ —	$ —
Property, plant and equipment of variable interest entities, net	$220,818	$ —	$ —
Liabilities			
Current liabilities	$3,353	$ —	$ —

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(13) 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 2015 Annual Report on Form 10-K.

Market Risk

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

- Commodity price risk associated with our natural long position in crude oil and natural gas reserves and production, our retail natural gas marketing activities, and our fuel procurement for certain of our gas-fired generation assets; 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 (Loss) and Condensed Consolidated Statements of Comprehensive Income (Loss) are detailed below and in Note 14.

Oil and Gas

We produce natural gas, NGLs and crude oil through our exploration and production activities. Our natural long positions, or unhedged open positions, result in commodity price risk and variability to our cash flows.

To mitigate commodity price risk and preserve cash flows, we primarily use exchange traded futures, swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on these instruments. These transactions were designated at inception as cash flow hedges, documented under accounting standards for derivatives and hedging, and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

The derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP. The effective portion of the gain or loss on these derivatives for which we have elected cash flow hedge accounting is reported in AOCI in the accompanying Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Revenue in the accompanying Condensed Consolidated Statements of Income (Loss).

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

	September 30, 2016			December 31, 2015		September 30, 2015	
	Crude Oil Futures	Natural Gas Futures and Swaps	Call Options	Crude Oil Futures	Natural Gas Futures and Swaps	Crude Oil Futures	Natural Gas Futures and Swaps
Notional [(a)]	159,000	1,625,000	36,000	198,000	4,392,500	258,000	5,392,500
Maximum terms in months [(b)]	27	15	15	24	24	27	27

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(a) Crude oil futures and call options in Bbls, natural gas in MMBtus.

(b) Term reflects the maximum forward period hedged.

Based on September 30, 2016 prices, a $2.4 million gain would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Estimated and actual realized gains or losses will change during future periods as market prices fluctuate.

Utilities

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

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

For hedging activities associated with our retail marketing operations, the effective portion of the gain or loss on these derivatives for which we have elected cash flow hedge accounting is reported in AOCI in the accompanying Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Fuel, purchased power and cost of natural gas sold in the accompanying Condensed Consolidated Statements of Income (Loss).

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, 2016		December 31, 2015		September 30, 2015	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	17,740,000	51	20,580,000	60	17,180,000	63
Natural gas options purchased, net [(b)]	6,540,000	17	2,620,000	3	6,300,000	6

Natural gas basis swaps purchased	13,650,000	51	18,150,000	60	12,980,000	51
Natural gas fixed for float swaps, net (c)	4,749,000	20	—	0	—	0
Natural gas physical commitments, net	15,666,202	13	—	0	—	0

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(a) Term reflects the maximum forward period hedged.

(b) Volumes purchased as of September 30, 2016 is net of 2,306,000 MMBtus of collar options (call purchase and put sale) transactions.

(c) 2,640,000 MMBtus were designated as cash flow hedges for the natural gas fixed for float swaps purchased.

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Financing Activities

In October 2015 and January 2016, we entered into forward starting interest rate swaps with a notional value totaling $400 million to reduce the interest rate risk associated with the anticipated issuance of senior notes. These swaps were settled at a loss of $29 million in connection with the issuance of our $400 million of unsecured ten-year senior notes on August 10, 2016. The effective portion of the loss in the amount of $28 million was recognized as a component of AOCI and will be recognized as a component of interest expense over the ten-year life of the $400 million unsecured senior note issued on August 19, 2016. The ineffectiveness portion of $1.0 million, related to the timing of the debt issuance, was recognized in earnings as a component of interest expense. The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	September 30, 2016	December 31, 2015		September 30, 2015
	Interest Rate Swaps [b]	Interest Rate Swaps [a]	Interest Rate Swaps [b]	Interest Rate Swaps [b]
Notional	$75,000	$250,000	$75,000	$75,000
Weighted average fixed interest rate	4.97 %	2.29 %	4.97 %	4.97 %
Maximum terms in years	0.33	1.33	1.00	1.33
Derivative assets, non-current	$—	$3,441	$—	$—
Derivative liabilities, current	$654	$—	$2,835	$3,312
Derivative liabilities, non-current	$—	$—	$156	$722

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(a) These swaps were settled in August 2016 in conjunction with the refinancing of acquired SourceGas debt.
(b) These swaps are designated to borrowings on our Revolving Credit Facility and are priced using three-month LIBOR, matching the floating portion of the related borrowings.

Based on September 30, 2016 market interest rates and balances related to our interest rate swaps, a loss of approximately $3.4 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. This total includes the amortization of the $28 million loss currently deferred in AOCI. Estimated and actual realized gains or losses will change during future periods as market interest rates change.

Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income (Loss) were as follows (in thousands):
Three Months Ended September 30, 2016

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	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	$ (465)	Interest expense	$ 840	Interest expense	$ —
Commodity derivatives	727	Revenue	(2,201)	Revenue	—

Commodity derivatives	(553)	Fuel, purchased power and cost of natural gas sold	(128)	Fuel, purchased power and cost of natural gas sold	—
Total	$ (291)		$ (1,489)		$ —

Three Months Ended September 30, 2015

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	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	$ (898)	Interest expense	$ 1,603	Interest expense	$ —
Commodity derivatives	5,280	Revenue	(3,109)	Revenue	—
Total	$ 4,382		$ (1,506)		$ —

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Nine Months Ended September 30, 2016

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	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	$ (31,130)	Interest expense	$ 2,530	Interest expense	$ —
Commodity derivatives	(312)	Revenue	(9,140)	Revenue	—
Commodity derivatives	220	Fuel, purchased power and cost of natural gas sold	23	Fuel, purchased power and cost of natural gas sold	—
Total	$ (31,222)		$ (6,587)		$ —

Nine Months Ended September 30, 2015

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	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	$ (2,674)	Interest expense	$ 4,709	Interest expense	$ —
Commodity derivatives	6,800	Revenue	(10,707)	Revenue	—
Total	$ 4,126		$ (5,998)		$ —

(14) 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 2015 Annual Report on Form 10-K filed with the SEC.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Valuation Methodologies for Derivatives

Oil and Gas Segment:

- The commodity contracts for our Oil and Gas segment are valued using the market approach and include exchange-traded futures, basis swaps and call options. Fair value was derived using exchange quoted settlement prices from third party brokers for similar instruments as to quantity and timing. The prices are then validated through third-party sources and therefore support Level 2 disclosure.

Utilities Segments:

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

Corporate Activities:

- The interest rate swaps are valued using the market approach. We establish fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting a Level 2 disclosure by using the credit default spread of the obligor, if available, or a generic credit default spread curve that takes into account our credit ratings, and the credit rating of our counterparty.

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

The following tables set forth by level within the fair value hierarchy are gross assets and gross liabilities and related offsetting cash collateral and counterparty netting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments.

	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	As of September 30, 2016				
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 2,882	$ —	$ —	$ 2,882
Commodity derivatives — Utilities	—	5,330	—	(3,647)	1,683
Interest Rate Swaps	—	—	—	—	—
Total	$ —	$ 8,212	$ —	$ (3,647)	$ 4,565
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 705	$ —	$ —	$ 705
Commodity derivatives — Utilities	—	16,130	—	(15,231)	899
Interest rate swaps	—	654	—	—	654
Total	$ —	$ 17,489	$ —	$ (15,231)	$ 2,258
	As of December 31, 2015				
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 10,644	$ —	$ (10,644)	$ —
Commodity derivatives —Utilities	—	2,293	—	(2,293)	—
Interest Rate Swaps	—	3,441	—	—	3,441
Total	$ —	$ 16,378	$ —	$ (12,937)	$ 3,441
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 556	$ —	$ (556)	$ —
Commodity derivatives — Utilities	—	24,585	—	(24,585)	—
Interest rate swaps	—	2,991	—	—	2,991
Total	$ —	$ 28,132	$ —	$ (25,141)	$ 2,991
	As of September 30, 2015				
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 11,264	$ —	$ (11,264)	$ —
Commodity derivatives — Utilities	—	3,123	—	(3,123)	—
Interest Rate Swaps	—	—	—	—	—

Total	$ —	$ 14,387	$ —	$ (14,387)	$ —
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 467	$ —	$ (467)	$ —
Commodity derivatives — Utilities	—	24,445	—	(24,445)	—
Interest rate swaps	—	4,034	—	—	4,034
Total	$ —	$ 28,946	$ —	$ (24,912)	$ 4,034

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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. Additionally, as of December 31, 2015, and September 30, 2015, the amounts below will not agree with the amounts presented on our Condensed Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 13 as they are netted in other current assets.

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

As of September 30, 2016

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 2,919	$ —
Commodity derivatives	Derivative assets — non-current	66	—
Interest rate swaps	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	479
Commodity derivatives	Derivative liabilities — non-current	—	256
Interest rate swaps	Derivative liabilities — current	—	654
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives designated as hedges		$ 2,985	$ 1,389
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 1,463	$ —
Commodity derivatives	Derivative assets — non-current	117	—
Commodity derivatives	Derivative liabilities — current	—	808
Commodity derivatives	Derivative liabilities — non-current	—	61
Total derivatives not designated as hedges		$ 1,580	$ 869

As of December 31, 2015

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 9,981	$ —
Commodity derivatives	Derivative assets — non-current	663	—
Interest rate swaps	Derivative assets — non-current	3,441	—
Commodity derivatives	Derivative liabilities — current	—	465
Commodity derivatives	Derivative liabilities — non-current	—	91
Interest rate swaps	Derivative liabilities — current	—	2,835
Interest rate swaps	Derivative liabilities — non-current	—	156
Total derivatives designated as hedges		$ 14,085	$ 3,547
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ —	$ —

Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	9,586
Commodity derivatives	Derivative liabilities — non-current	—	12,706
Total derivatives not designated as hedges		$ —	$ 22,292

As of September 30, 2015

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 9,181	$ —
Commodity derivatives	Derivative assets — non-current	2,083	—
Commodity derivatives	Derivative liabilities — current	—	375
Commodity derivatives	Derivative liabilities — non-current	—	92
Interest rate swaps	Derivative liabilities — current	—	3,312
Interest rate swaps	Derivative liabilities — non-current	—	722
Total derivatives designated as hedges		$ 11,264	$ 4,501
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ —	$ —
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	8,427
Commodity derivatives	Derivative liabilities — non-current	—	12,895
Total derivatives not designated as hedges		$ —	$ 21,322

(15) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 14, were as follows (in thousands) as of:

	September 30, 2016		December 31, 2015		September 30, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$62,964	$62,964	$456,535	$456,535	$38,841	$38,841
Restricted cash and equivalents [(a)]	$2,140	$2,140	$1,697	$1,697	$2,462	$2,462
Notes payable [(a)]	$75,000	$75,000	$76,800	$76,800	$117,900	$117,900
Long-term debt, including current maturities, net of deferred financing costs [(b)]	$3,217,511	$3,525,362	$1,853,682	$1,992,274	$1,553,167	$1,718,964

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

(b) 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.

(16) OTHER COMPREHENSIVE INCOME (LOSS)

The components of the reclassification adjustments, net of tax, included in Other Comprehensive Income (Loss) for the periods were as follows (in thousands):

	Location on the Condensed Consolidated Statements of Income (Loss)	Amount Reclassified from AOCI			
		Three Months Ended		Nine Months Ended	
		September 30, 2016	September 30, 2015	September 30, 2016	September 30, 2015
Gains and losses on cash flow hedges:					
Interest rate swaps	Interest expense	$840	$ 1,603	$2,530	$ 4,709
Commodity contracts	Revenue	(2,201)	(3,109)	(9,140)	(10,707)
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(128)	—	23	—
		(1,489)	(1,506)	(6,587)	(5,998)
Income tax	Income tax benefit (expense)	566	558	2,450	2,548
Reclassification adjustments related to cash flow hedges, net of tax		$(923)	$ (948)	$(4,137)	$ (3,450)
Amortization of defined benefit plans:					
Prior service cost	Operations and maintenance	$(55)	$ (55)	$(165)	$ (166)
Actuarial gain (loss)	Operations and maintenance	494	706	1,482	2,116
		439	651	1,317	1,950
Income tax	Income tax benefit (expense)	(152)	(228)	(459)	(684)
Reclassification adjustments related to defined benefit plans, net of tax		$287	$ 423	$858	$ 1,266

Balances by classification included within Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets are as follows (in thousands):

	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
Balance as of December 31, 2014	$(3,912)	$ 9,005	$(20,137)	$(15,044)
Other comprehensive income (loss), net of tax	332	263	395	990
Balance as of March 31, 2015	(3,580)	9,268	(19,742)	(14,054)
Other comprehensive income (loss), net of tax	503	(3,730)	422	(2,805)
Balance as of June 30, 2015	(3,077)	5,538	(19,320)	(16,859)
Other comprehensive income (loss), net of tax	457	1,368	423	2,248
Ending Balance September 30, 2015	$(2,620)	$ 6,906	$(18,897)	$(14,611)
Balance as of December 31, 2015	$294	$ 6,431	$(15,780)	$(9,055)
Other comprehensive income (loss), net of tax	(11,171)	(885)	286	(11,770)
Balance as of March 31, 2016	(10,877)	5,546	(15,494)	(20,825)
Other comprehensive income (loss), net of tax	(7,649)	(3,575)	285	(10,939)
Balance as of June 30, 2016	(18,526)	1,971	(15,209)	(31,764)
Other comprehensive income (loss), net of tax	244	(1,718)	287	(1,187)
Ending Balance September 30, 2016	$(18,282)	$ 253	$(14,922)	$(32,951)

(17) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Nine months ended	September 30, 2016	September 30, 2015
	(in thousands)	
Non-cash investing and financing activities—		
Property, plant and equipment acquired with accrued liabilities	$44,140	$52,314
Increase (decrease) in capitalized assets associated with asset retirement obligations	$(2,285)	$—
Cash (paid) refunded during the period —		
Interest (net of amounts capitalized)	$(82,639)	$(49,797)
Income taxes, net	$(1,168)	$(1,202)

(18) EMPLOYEE BENEFIT PLANS

On February 12, 2016, as disclosed in Note 2, we completed the acquisition of SourceGas, adding an additional defined benefit pension plan, two additional non-pension defined benefit postretirement plans and a 401K retirement savings plan to cover employees of the utilities acquired. Benefits under these plans are determined based on each employee's compensation, years of service, and/or age at retirement, among other factors.

In accordance with ASC 715, the SourceGas benefit liabilities were re-measured as of February 11, 2016. In addition, prior service costs not previously expensed were reclassified to a Regulatory asset and will be amortized over the average remaining service life of the plans.

Amounts recognized in the Condensed Consolidated Balance Sheets upon the February 12, 2016 acquisition are (in thousands):

	Defined Benefit Pension Plan	Non-Pension Defined Benefit Postretirement Plans
Unfunded postretirement benefit obligation	$22,187	$ 11,751

Defined Benefit Pension Plans

We have three defined benefit pension plans for certain eligible employees consisting of the Black Hills Corporation pension plan, Black Hills Utility Holdings' pension plan and the SourceGas retirement plan. The benefits for the pension plans are based on years of service and calculations of average earnings during a specific time period prior to retirement. All Pension Plans have been closed to new employees and frozen for certain employees who did not meet age and service based criteria.

Beginning in 2016, we changed the method used to estimate the service and interest cost components of the net periodic pension, supplemental non-qualified defined benefit and other postretirement benefit costs. The new method uses the spot yield curve approach to estimate the service and interest costs by applying the specific spot rates along the yield curve used to determine the benefit obligations to relevant projected cash outflows. Previously, those costs were determined using a single weighted-average discount rate. The change does not affect the measurement of the total benefit obligations as the change in service and interest costs offsets the actuarial gains and losses recorded in other comprehensive income, regulatory assets or regulatory liabilities. The new method provides a more precise measure of interest and service costs by improving the correlation between the projected benefit cash flows and the discrete spot yield curve rates. We accounted for this change as a change in estimate prospectively beginning in the first quarter of 2016. The discount rates used to measure the 2016 service costs are 4.749%, 4.880% and 4.372% for pension, supplemental non-qualified defined benefit and other postretirement benefit costs, respectively. The discount rates used to measure the 2016 interest costs are 3.827%, 3.817% and 3.284% for pension, supplemental non-qualified defined benefit and other postretirement benefit costs, respectively. The previous method would have used a discount rate for both service and interest costs of 4.575% for pension, 4.500% for supplemental non-qualified defined benefit and 4.165% for other postretirement benefit costs. The decrease in the total 2016 service and interest costs is approximately $2.8 million, $0.3 million and $0.4 million for the pension, supplemental non-qualified defined benefit and other postretirement benefit costs, respectively, as compared to the previous method.

In connection with the acquisition related re-measurement of the SourceGas benefit plans we adopted the spot yield curve method, referenced above. The discount rates used to measure the 2016 interest costs are 3.690% for pension and 3.319% for other post retirement costs, effective February 11, 2016.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Service cost	$2,078	$1,494	$6,234	$4,482
Interest cost	3,936	3,880	11,808	11,640
Expected return on plan assets	(5,766)	(4,867)	(17,297)	(14,601)
Prior service cost	15	15	45	45
Net loss (gain)	1,793	2,759	5,379	8,277
Net periodic benefit cost	$2,056	$3,281	$6,169	$9,843

Defined Benefit Postretirement Healthcare Plans

With the addition of the two SourceGas Postretirement Healthcare Plans, BHC now sponsors five retiree healthcare plans (Healthcare Plans) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. A portion of the Healthcare Plans is pre-funded via Voluntary Employees' Beneficiary Association, "VEBAs". Effective January 1, 2014, health care coverage for Medicare-eligible retirees is provided through an individual market healthcare exchange for BHC and Black Hills Utility Holdings retirees. SourceGas retirees do not participate in the individual market healthcare exchange; therefore, all permissible health claims are paid under the self-insured plan.

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,	
	2016	2015	2016	2015
Service cost	$467	$464	$1,401	$1,392
Interest cost	485	450	1,455	1,350
Expected return on plan assets	(70)	(33)	(210)	(99)
Prior service cost (benefit)	(107)	(107)	(321)	(321)
Net loss (gain)	84	102	252	306
Net periodic benefit cost	$859	$876	$2,577	$2,628

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,	
	2016	2015	2016	2015
Service cost	$623	$(84)	$1,530	$799
Interest cost	314	364	943	1,092

Prior service cost	1	1	2	3
Net loss (gain)	207	270	621	810
Net periodic benefit cost	$1,145	$551	$3,096	$2,704

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Contributions

We anticipate that we will make contributions to the benefit plans in 2016 and 2017. Contributions to the Defined Benefit Pension Plans are cash contributions made directly to the Pension Plan Trust accounts. Contributions to the Healthcare and Supplemental Plans are made in the form of benefit payments. Contributions and anticipated contributions are as follows (in thousands):

	Contributions Made		Contributions Made		Additional Contributions		Contributions	
	Three Months Ended September 30, 2016		Nine Months Ended September 30, 2016		Anticipated for 2016		Anticipated for 2017	
Defined Benefit Pension Plans	$	4,000	$	14,200	$	—	$	10,200
Non-pension Defined Benefit Postretirement Healthcare Plans	$	1,192	$	3,576	$	1,192	$	4,744
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$	392	$	1,176	$	392	$	1,627

(19) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 20 of our Notes to the Consolidated Financial Statements in our 2015 Annual Report on Form 10-K except for those described below and in Notes 2 and 22.

Gas Supply Agreements

Acquired Utilities

In connection with the SourceGas Acquisition (see Note 2), we assumed various commitments relating to natural gas supply and transportation commitments and lease commitments, as summarized below (in thousands):

	2016	2017	2018	2019	2020	Thereafter	Total
Future minimum payments							
Pipeline capacity obligations	$9,718	$31,088	$34,676	$30,878	$30,878	$149,554	$286,792
Facilities and equipment	758	2,236	2,230	1,698	1,382	3,337	11,641
Total	$10,476	$33,324	$36,906	$32,576	$32,260	$152,891	$298,433

Also due to the acquisition, there are other commitments to purchase natural gas to meet customer needs, which are short-term or long-term in nature. At September 30, 2016, the long-term commitments to purchase physical quantities of natural gas under contracts indexed to the following indices were as follows:

	MMBtu (in thousands)					
	2016	2017	2018	2019	2020	Total
Natural Gas Indices						
Colorado Interstate Gas	1,355	6,684	—	—	—	8,039

Panhandle Eastern Pipeline	239	—	—	—	—	239
Northwest Wyoming Pool	488	1,208	1,208	720	—	3,624
El Paso San Juan	98	270	—	—	—	368

Purchases under these contracts totaled $6.2 million for the nine months ended September 30, 2016, of which $1.6 million is recovered under the applicable states’ purchased-gas recovery mechanisms.

Build Transfer Agreement

On November 2, 2015, Colorado Electric executed a build-transfer agreement with Invenergy Wind Development Colorado, LLC to purchase the 60 MW, $109 million Peak View Wind Project. Peak View will be built by Invenergy Wind Development Colorado, LLC approximately 30 miles south of Pueblo, Colorado, in Huerfano and Las Animas counties. The estimated cost of $109 million includes taxes, transmission infrastructure and interconnection costs. Construction started in February of 2016 and is expected to be completed in late 2016. Under the build transfer agreement, Colorado Electric makes progress payments to Invenergy, which started in late 2015, and continue through completion of the project. Ownership of Peak View will transfer to Colorado Electric prior to commercial operation and will be operated as a utility-owned asset. BHC has guaranteed the full and complete payment and performance on behalf of Colorado Electric. At September 30, 2016, the balance of BHC’s guarantee was approximately $24 million. The balance of the guarantee decreases as progress payments are made. The guarantee terminates at the earlier of 1) when BHC or Colorado Electric has paid and performed all guaranteed obligations, or 2) the second anniversary of the closing date.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of September 30, 2016, we were in compliance with the debt covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at September 30, 2016:

- Our utilities are generally limited to the amount of dividends allowed to be paid to us as a utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions and financing agreements. As of September 30, 2016, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

(20) IMPAIRMENT OF ASSETS

Long-lived Assets

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

In determining the ceiling value of our assets under the full cost accounting rules of the SEC, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. As a result of continued low commodity prices in 2016 and throughout 2015, we recorded the following non-cash ceiling test impairments of our oil and gas assets included in our Oil and Gas segment for the three and nine months ended September 30, 2016 and September 30, 2015.

- During the three and nine months ended September 30, 2016, we recorded pre-tax non-cash impairments of oil and gas assets included in our Oil and Gas segment of $12 million and $38 million, respectively. At September 30, 2016, the average NYMEX natural gas price was $2.28 per Mcf, adjusted to $1.03 per Mcf at the wellhead; the average NYMEX crude oil price was $41.68 per barrel, adjusted to $35.88 per barrel at the wellhead.

- During the three and nine months ended September 30, 2015, we recorded pre-tax non-cash impairments of oil and gas assets included in our Oil and Gas segment of $62 million and $178 million, respectively. At September 30, 2015, the average NYMEX natural gas price was $3.06 per Mcf, adjusted to $1.72 per Mcf at the wellhead; the average NYMEX crude oil price was $59.21 per barrel, adjusted to $52.82 per barrel at the wellhead.

During the second quarter of 2016, we advanced our Oil and Gas strategy, identifying certain non-core assets which may be sold as they are not expected to be utilized in the Cost of Service Gas Program. We assessed these assets for impairment in accordance with ASC 360. We valued the assets applying a market method approach utilizing assumptions consistent with similar known and measurable transactions and determined that the carrying amount exceeded the fair value. As a result, we recorded a pre-tax impairment of depreciable properties at June 30, 2016 of $14 million, in addition to the impairments noted above.

Equity Investments in Unconsolidated Subsidiaries

At June 30, 2015, our Oil and Gas segment owned a 25% interest in a pipeline and gathering system, accounted for under the equity method of accounting. Due to sustained low commodity prices, recurring operating losses and future expectations, we reviewed this investment interest for impairment utilizing the other-than-temporary impairment model under ASC 820, Fair Value Measurements. We valued this investment applying a market method approach utilizing assumptions consistent with similar known and measurable transactions. The carrying amount of this equity method investment exceeded the fair value, and we concluded the decline is considered to be other than temporary. As a result we recorded a pre-tax impairment loss at June 30, 2015 of $5.2 million, the difference between the carrying amount and the fair value of the investment. In December of 2015, we sold our 25% interest in this pipeline and gathering system.

(21) INCOME TAXES

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

	Three Months Ended September 30,	
Tax (benefit) expense [c]	2016	2015
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect) [a]	(4.0)	4.7
Percentage depletion in excess of cost	(2.3)	2.0
Accounting for uncertain tax positions adjustment	(2.4)	(1.2)
Noncontrolling interest [b]	(3.7)	—
Flow-through adjustments	(2.2)	2.4
Inter-period adjustment	7.2	11.2
AFUDC equity	(0.6)	—
Other tax differences	0.1	0.7
	27.1 %	54.8 %

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

(b) The reconciling item reflects limited liability company (LLC) income not subject to tax. Black Hills Colorado IPP went from a single member LLC wholly-owned by Black Hills Electric Generation to a partnership as a result of the sale of 49.9% of its membership interests in April 2016.

(c) The tax rate for the three months ended September 30, 2015 represents a tax benefit due to the net loss for the period.

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

	Nine Months Ended September 30,	
Tax (benefit) expense [e]	2016	2015
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect)	1.7	6.7
Percentage depletion in excess of cost [c]	(9.7)	4.5
Inter-period adjustment	0.1	—
Accounting for uncertain tax positions adjustment [d]	(7.7)	(4.7)
Noncontrolling interest	(2.5)	—
Transaction costs	1.4	—
Flow-through adjustments	(1.9)	4.7
Other tax differences	(0.9)	(1.3)
	15.5 %	44.9 %

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

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

(e) The tax rate for the nine months ended September 30, 2015 represents a tax benefit due to the net loss for the period.

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

(22) 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, 2016	December 31, 2015	September 30, 2015
Accrued employee compensation, benefits and withholdings	$ 57,203	$ 43,342	$ 43,390

Accrued property taxes	37,156	32,393	30,669
Accrued payments related to litigation expenses and settlements	—	38,750	33,375
Customer deposits and prepayments	51,137	53,496	33,225
Accrued interest and contract adjustment payments	42,612	25,762	22,839
CIAC current portion	5,465	14,745	16,604
Other (none of which is individually significant)	34,949	23,573	49,787
Total accrued liabilities	$ 228,522	$ 232,061	$ 229,889

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

We are a customer-focused, growth-oriented, vertically-integrated 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 207,000 customers in South Dakota, Wyoming, Colorado and Montana. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates.

Gas Utilities: Our Gas Utilities conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Wyoming and Nebraska subsidiaries. Our Gas Utilities distribute and transport natural gas through our network to approximately 1,021,000 natural gas customers. Additionally, we sell temporarily-available, contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates.

We also provide non-regulated services through Black Hills Energy Services, our gas marketing affiliate, and through our Service Guard and Tech Services product lines. Black Hills Energy Services provides approximately 59,000 retail distribution customers in Nebraska and Wyoming with unbundled natural gas commodity offerings under the regulatory-approved Choice Gas program. Service Guard primarily provides appliance repair services to approximately 64,000 residential customers through company technicians and third party service providers, typically through on-going monthly service agreements. Tech Services primarily serves gas transportation customers throughout our service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.

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

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

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

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. Prior to March 31, 2016, our segments were reported within two business groups, our Utilities Group, containing the Electric Utilities and Gas Utilities segments, and our Non-regulated Energy Group, containing the Power Generation, Coal Mining and Oil and Gas segments. We have continued to report our operations consistently through our reportable segments; however, we will no longer separate the segments by business group. We are a customer-focused, growth-oriented, vertically-integrated utility company. All of our non-utility business segments support our utilities, with the exception of our Oil and Gas segment.

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for our electric utilities is June through August while the normal peak usage season for our gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2016 and 2015, and our financial condition as of September 30, 2016, December 31, 2015 and September 30, 2015, 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.

SourceGas Acquisition

On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing. The purchase price was subject to post-closing adjustments of which $11 million was agreed to and received in June 2016.

SourceGas primarily operates four regulated natural gas utilities serving approximately 429,000 customers in Arkansas, Colorado, Nebraska and Wyoming and a 512 mile regulated intrastate natural gas transmission pipeline in Colorado. SourceGas has been renamed Black Hills Gas Holdings, LLC and is a 99.5% owned subsidiary of Black Hills Utility Holdings. See Note 2 in Item 1 of Part I of this Quarterly Report on Form 10-Q for more information regarding the acquisition.

Segment reporting transition of Cheyenne Light's Natural Gas distribution

Effective January 1, 2016, the natural gas operations of Cheyenne Light are reported in our Gas Utilities Segment. Through December 31, 2015, Cheyenne Light's natural gas operations were included in our Electric Utilities Segment as these natural gas operations were consolidated within Cheyenne Light since its acquisition. This change is a result of our business segment reorganization to, among other things, integrate all regulated natural gas operations, including the SourceGas Acquisition, into our Gas Utilities Segment which is led by the Group Vice President, Natural Gas Utilities. Likewise, all regulated electric utility operations including Cheyenne Light's electric utility operations are reported in our Electric Utilities Segment, which is led by the Group Vice President, Electric Utilities. The prior period has been reclassified to reflect this change in presentation between the Electric Utilities and Gas Utilities segments. The reclassifications moving Cheyenne Light's natural gas results from the Electric Utilities segment to the Gas Utilities segment consisted of increasing Gas Utilities and decreasing (increasing) Electric Utilities Revenue, Gross Margin and Net Income (loss) by $6.2 million, $4.1 million and $(0.7) million, respectively, for the three months ended September 30, 2015, and $31 million, $15 million and $0.8 million, respectively, for the nine months ended September 30, 2015.

Utility Rebranding

All of our utilities are now operating with the trade name Black Hills Energy. We have expanded our regulated operations with the acquisition of SourceGas, as well as with our 2015 utility acquisitions. We have rebranded our Cheyenne Light utilities, Black Hills Power utility and our SourceGas utilities to operate under the name Black Hills Energy, conforming to the name under which our other utilities operate. Within our Electric utilities segment and our Gas Utilities segment, references made to our utilities are presented as follows according to their respective state:

Electric Utilities Segment

- Black Hills Energy South Dakota Electric - includes all Black Hills Power utility operations in South Dakota, Wyoming and Montana.

- Black Hills Energy Wyoming Electric - includes all Cheyenne Light electric utility operations.

- Black Hills Energy Colorado Electric - includes all Colorado Electric utility operations.

Gas Utilities Segment

- Black Hills Energy Arkansas Gas - includes the results from the acquired SourceGas utility Black Hills Energy Arkansas operations.

- Black Hills Energy Colorado Gas - includes Black Hills Energy Colorado Gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution’s Colorado operations and RMNG operations.

- Black Hills Energy Nebraska Gas - includes Black Hills Energy Nebraska gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution’s Nebraska operations.

- Black Hills Energy Iowa Gas - includes Black Hills Energy Iowa gas utility operations.

- Black Hills Energy Kansas Gas - includes Black Hills Energy Kansas gas utility operations.

- Black Hills Energy Wyoming Gas - includes Cheyenne Light's natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Wyoming operations.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 84.

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, 2016 Compared to Three Months Ended September 30, 2015. Net income (loss) available for common stock for the three months ended September 30, 2016 was $14 million, or $0.26 per share, compared to Net income (loss) available for common stock of $(9.9) million, or $(0.22) per share, reported for the same period in 2015. The Net income (loss) available for common stock for the three months ended September 30, 2016 increased over the same period in the prior year primarily due to higher earnings at our Electric Utilities, and a decrease in impairment charges on our oil and gas properties. Net income (loss) available for common stock for the three months ended September 30, 2016 included a non-cash after-tax impairment of oil and gas properties of $7.9 million compared to a non-cash after-tax impairment of $36 million in the same period of the prior year. The Net income (loss) available for common stock for the three months ended September 30, 2016 is net of $3.8 million of net income attributable to noncontrolling interests and includes a loss of $3.8 million from our acquired SourceGas utilities and after-tax SourceGas acquisition and transition related costs of $4.0 million. The Net income (loss) available for common stock for the three months ended September 30, 2015 included after-tax SourceGas acquisition and transition related costs of $2.8 million.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. Net income (loss) available for common stock for the nine months ended September 30, 2016 was $55 million, or $1.04 per share, compared to Net income (loss) available for common stock of $(18) million, or $(0.40) per share, reported for the same period in 2015. The Net income (loss) available for common stock for the nine months ended September 30, 2016, net of $6.4 million of net income attributable to noncontrolling interests, increased over the same period in the prior year due primarily to lower impairment charges of our Oil and Gas properties; higher earnings at our Electric and Gas Utilities, which include earnings of $0.8 million from our acquired SourceGas utilities since the acquisition date of February 12, 2016; approximately $11 million in tax benefits recognized in the first quarter of 2016 from additional percentage depletion deductions that are being claimed with respect to our oil and gas properties; and the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016. The nine months ended September 30, 2016 also included non-cash after-tax impairments of our oil and gas properties of $33 million and after-tax SourceGas acquisition and transition costs of $24 million. The Net income (loss) available for common stock for the nine months ended September 30, 2015 included a non-cash after-tax ceiling test impairment of our oil and gas properties of $113 million, after-tax SourceGas acquisition and transition costs of $3.0 million, and a non-cash after-tax impairment loss on an equity investment of $3.4 million.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Variance	2016	2015	Variance
Revenue						
Revenue	$365,742	$303,856	$61,886	$1,205,305	$1,080,819	$124,486
Inter-company eliminations	(31,956)	(31,751)	(205)	(96,119)	(94,473)	(1,646)
	$333,786	$272,105	$61,681	$1,109,186	$986,346	$122,840
Net income (loss) available for common stock						
Electric Utilities	$24,181	$22,659	$1,522	$62,625	$57,844	$4,781
Gas Utilities	(2,939)	652	(3,591)	29,975	27,475	2,500
Power Generation	5,642	9,067	(3,425)	19,907	24,761	(4,854)
Mining	3,307	3,047	260	6,969	9,106	(2,137)
Oil and Gas [(a)] [(b)] [(c)]	(8,828)	(39,769)	30,941	(35,277)	(130,079)	94,802
	21,363	(4,344)	25,707	84,199	(10,893)	95,092
Corporate activities and eliminations [(d)] [(e)]	(7,232)	(5,599)	(1,633)	(29,397)	(7,042)	(22,355)
Net income (loss) available for common stock	$14,131	$(9,943)	$24,074	$54,802	$(17,935)	$72,737

(a) Net income (loss) available for common stock for the three and nine months ended September 30, 2016 and September 30, 2015 included non-cash after-tax impairments of our oil and gas properties of $7.9 million and $33 million and $36 million and $113 million, respectively. See Note 20 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

(c) Net income (loss) available for common stock for the nine months ended September 30, 2015 included a non-cash after-tax impairment to equity investments of $3.4 million.

(d) Net income (loss) available for common stock for the three and nine months ended September 30, 2016 and September 30, 2015 included incremental, non-recurring acquisition costs, after-tax of $4.0 million and $24 million, and $2.8 million and $3.0 million, respectively, and after-tax internal labor costs attributable to the acquisition of $1.7 million and $7.4 million, and $1.2 million and $1.8 million respectively. See Note 2 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(e) Net income (loss) available for common stock for the nine months ended September 30, 2016 included tax benefits of approximately $4.4 million as a result of the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016.

Overview of Business Segments and Corporate Activity

Electric Utilities Segment

- Electric Utilities experienced milder and hotter weather, respectively, during the three and nine months ended September 30, 2016 compared to the three and nine months ended September 30, 2015. Cooling degree days were 3% lower and 8% higher, respectively for the three and nine months ended September 30, 2016, compared to the same periods in 2015. Cooling degree days for the three and nine months ended September 30, 2016 were 15% and 26% higher than normal, compared to 19% and 16% higher than normal for the same periods in 2015.

- On May 3, 2016, Colorado Electric filed a request with the Colorado Public Utilities Commission to increase its annual revenues by $8.9 million to recover investments in a $65 million, 40 MW natural gas-fired combustion turbine, currently under construction. Construction on the turbine continued in the third quarter of 2016. Through September 30, 2016, approximately $56 million was expended, and the project is on schedule to be completed and placed into service in the fourth quarter of 2016. Construction riders related to the project increased gross margins by approximately $1.6 million and $3.8 million for the three and nine months ended September 30, 2016, respectively. Hearings were held regarding this matter in October 2016 and we expect new rates to be effective January 1, 2017.

- During the first quarter of 2016, South Dakota Electric commenced construction of the $54 million, 230-kV, 144 mile-long transmission line that will connect the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange is expected to be placed in service in the first half of 2017.

- On June 23, 2015, Colorado Electric filed for a CPCN with the CPUC to acquire the planned $109 million, 60 MW Peak View Wind Project, to be located near Colorado Electric's Busch Ranch wind farm. This renewable energy project was originally submitted in response to Colorado Electric's all-source generation request on May 5, 2014. On October 21, 2015, the Commission approved a build transfer proposal and settlement agreement. The settlement provides for recovery of the costs of the project through Colorado Electric’s Electric Cost Adjustments and Renewable Energy Standard Surcharge for 10 years, after which Colorado Electric can propose base rate recovery. Colorado Electric will be required to make an annual comparison of the cost of the renewable energy generated by the facility against the bid cost of a PPA from the same facility. Colorado Electric will purchase the project for approximately $109 million through progress payments throughout 2016, with ownership transfer occurring just before achieving commercial operation. The project is being built by Invenergy Wind Development Colorado LLC and all 34 turbines have been constructed and tested. Commercial operation is expected in the fourth quarter of 2016. Through September 30, 2016, approximately $96 million was expended on the project.

Gas Utilities Segment

- Gas Utilities experienced cooler and milder weather, respectively, during the three and nine months ended September 30, 2016 compared to the three and nine months ended September 30, 2015. Heating degree days were 147% higher and 17% lower, respectively, for the three and nine months ended September 30, 2016, compared to the same periods in 2015. Heating degree days for the three and nine months ended September 30, 2016 were 35% higher and 9% lower than normal, respectively, compared to 57% and 2% lower than normal for the same periods in 2015.

- During the third quarter of 2016, the Company withdrew its Cost of Service Gas applications in Wyoming, Iowa, Kansas and South Dakota. In consideration of the July 19, 2016 denial of the application from the NPSC and the April 2016 dismissal of its application from the CPUC, the Company is re-evaluating its Cost of Service Gas regulatory approval strategy.

The Company’s initial applications submitted in late 2015 were based on a two-phase approach, the first of which would establish the criteria for how the program would work, and the second would seek approval for a specific gas reserves property. The orders in Colorado and Nebraska indicated the initial phase filings contained insufficient information and data to support customer benefits. Based on pre-hearing discovery and commission orders, the Company is considering filing new applications for approval of specific gas reserve properties.

Power Generation Segment

- Black Hills Colorado IPP owns and operates a 200 MW, combined cycle natural gas generating facility located in Pueblo, Colorado. On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million. FERC approval of the sale was received on March 29, 2016. Proceeds from the sale were used to pay down short-term debt. Black Hills Electric Generation continues to be the majority owner and operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric.

Oil and Gas Segment

- Our Oil and Gas segment was impacted by lower net hedged prices received for crude oil and natural gas for the three and nine months ended September 30, 2016 compared to the same periods in 2015. The average hedged price received for natural gas decreased by 4% and 32%, respectively, for the three and nine months ended September 30, 2016 compared to the same periods in 2015. The average hedged price received for oil decreased by 3% and 14%, respectively, for the three and nine months ended September 30, 2016 compared to the same periods in 2015. Oil and Gas production volumes increased 5% and 0%, respectively, for the three and nine months ended September 30, 2016 compared to the same periods in 2015.

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- Oil and Gas results benefited by $5.8 million from a change in estimate related to income taxes. The tax benefit relates to additional percentage depletion deductions that are being claimed with respect to the oil and gas properties. The benefit recorded in the first quarter of 2016 includes a change in estimate recorded for income tax accounting purposes. This benefit was the result of completion of a study to analyze prior depletion claimed dating back to 2007.

- We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC on a quarterly basis, known as a ceiling test. For the three and nine months ended September 30, 2016, our Oil and Gas segment recorded pre-tax, non-cash ceiling test impairments of $12 million and $38 million, respectively as a result of continued low commodity prices. We also recorded a $14 million impairment of other Oil and Gas depreciable properties not included in our full cost pool during the second quarter of 2016 as we decided to divest non-core oil and gas assets.

Corporate Activities

- On August 19, 2016, we completed a public debt offering of $700 million principal amount of senior unsecured notes. The debt offering consisted of $400 million of 3.15% 10-year senior notes due January 15, 2027 and $300 million of 4.20% 30-year senior notes due September 15, 2046. The proceeds of the notes were used for the following:

Repay the $325 million 5.9% senior unsecured notes assumed in the SourceGas Acquisition;

Repay the $95 million, 3.98% senior secured notes assumed in the SourceGas Acquisition;

Repay the remaining $100 million on the $340 million unsecured term loan assumed in the SourceGas Acquisition;

Pay down $100 million of the $500 million three-year unsecured term loan discussed below;

Payment of $29 million for the settlement of $400 million notional interest rate swaps; and

Remainder was used for general corporate purposes.

- On August 9, 2016, we entered into a $500 million, three-year, unsecured term loan expiring on August 9, 2019. The proceeds of this term loan was used to pay down $240 million of the $340 million unsecured term loan assumed in the SourceGas Acquisition and the $260 million term loan expiring on April 12, 2017.

- On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extended the term through August 9, 2021, with two one-year extension options. The facility includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase total commitments of the facility up to $1 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options, which are substantially the same as the former agreement.

- During the first quarter of 2016, we reached an agreement in principle with IRS Appeals with respect to our liability for unrecognized tax benefits attributable to the like-kind exchange effectuated in connection with the 2008 IPP Transaction and the 2008 Aquila Transaction. This agreement resulted in a tax benefit of approximately $5.1 million in the first quarter of 2016. See Note 21 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q for additional details on this agreement.

- On March 18, 2016, we implemented an ATM equity offering program allowing us to sell shares of our common stock with an aggregate value of up to $200 million. The shares may be offered from time to time pursuant to a sales agreement dated March 18, 2016. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. During the three months ended September 30, 2016, we issued 819,442 common shares for $49 million, net of $0.5 million in commissions under the ATM equity offering program. Through September 30, 2016, we have sold and issued an aggregate of 1,750,091 shares of common stock under the ATM equity offering program for $106 million, net of $1.1 million in commissions. Additionally, 38,781 shares for net proceeds of $2.4 million have been sold, but were not settled and are not considered issued and outstanding as of September 30, 2016.

- On February 12, 2016, Black Hills Utility Holdings acquired SourceGas, pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in long-term debt at closing. In June 2016 we agreed to and received a working capital adjustment of $11 million. SourceGas operates four regulated natural gas utilities serving approximately 429,000 customers in Arkansas, Colorado, Nebraska and Wyoming, and a 512 mile regulated intrastate natural gas transmission pipeline in Colorado. We funded the majority of the SourceGas Transaction with the following financings:

  On January 13, 2016, we completed a public debt offering of $550 million in senior unsecured notes. The debt offering consisted of $300 million of 3.95%, 10-year senior notes due 2026, and $250 million of 2.50%, 3-year senior notes due 2019. Net proceeds after discounts and fees were approximately $546 million; and

  On November 23, 2015, we completed the offerings of common stock and equity units. We issued 6.325 million shares of common stock for net proceeds of $246 million and 5.98 million equity units for net proceeds of $290 million.

- On February 12, 2016, Moody's affirmed the BHC credit rating of Baa1 and maintained a negative outlook following our acquisition of SourceGas. Moody’s maintained a negative outlook while monitoring BHC’s progress toward integrating the SourceGas assets subsequent to closing, consummating the sale of the 49.9% noncontrolling interest of our Colorado IPP assets and utilizing an ATM equity offering program. In addition, the negative outlook reflects overall weaker consolidated metrics when compared to historical ranges.

- On February 12, 2016, S&P affirmed the BHC credit rating of BBB and maintained a stable outlook after our acquisition of SourceGas, reflecting their expectation that management will continue to focus on the core utility operations while maintaining an excellent business risk profile following the acquisition.

- On February 12, 2016, Fitch affirmed the BHC credit rating of BBB+ and maintained a negative outlook after our acquisition of SourceGas, which reflects the initial increased leverage associated with the SourceGas Acquisition.

- On January 20, 2016, we executed a 10-year, $150 million notional, forward starting pay fixed interest rate swap at an all-in interest rate of 2.09%, and on October 2, 2015, we executed a 10-year, $250 million notional forward starting pay fixed interest rate swap at an all-in rate of 2.29%, to hedge the risks of interest rate movement between the hedge dates and pricing date for long-term debt refinancings occurring in August 2016. On August 19, 2016, we settled and terminated these interest rate swaps for a loss of $29 million, as discussed above. The loss recorded in AOCI will be amortized over the 10 year life of the associated debt.

Operating Results

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

Non-GAAP Financial Measure
The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, gross margin, that is considered a “non-GAAP financial measure.” Generally, a non-GAAP financial measure is a numerical measure of a company’s financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of gross margin is intended to supplement investors’ understanding of our operating performance.

Gross margin for our Electric Utilities is calculated as operating revenue less cost of fuel and purchased power. Gross margin for our Gas Utilities is calculated as operating revenues less cost of natural gas sold. Our gross margin is impacted by the fluctuations in power purchases and natural gas and other fuel supply costs. However, while these fluctuating costs impact gross margin as a percentage of revenue, they only impact total gross margin if the costs cannot be passed through to our customers.

Our gross margin measure may not be comparable to other companies’ gross margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Variance	2016	2015	Variance
	(in thousands)					
Revenue	$174,501	$178,590	$(4,089)	$503,258	$512,530	$(9,272)
Total fuel and purchased power	66,953	71,253	(4,300)	194,477	203,128	(8,651)
Gross margin	107,548	107,337	211	308,781	309,402	(621)
Operations and maintenance	38,108	40,538	(2,430)	116,312	122,509	(6,197)
Depreciation and amortization	21,063	20,122	941	62,794	60,344	2,450
Total operating expenses	59,171	60,660	(1,489)	179,106	182,853	(3,747)
Operating income	48,377	46,677	1,700	129,675	126,549	3,126
Interest expense, net	(12,046)	(12,455)	409	(36,676)	(38,670)	1,994
Other income (expense), net	1,335	806	529	2,828	1,047	1,781
Income tax benefit (expense)	(13,485)	(12,369)	(1,116)	(33,202)	(31,082)	(2,120)
Net income (loss)	$24,181	$22,659	$1,522	$62,625	$57,844	$4,781

Revenue - Electric (in thousands)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Residential:				
South Dakota Electric	$17,501	$18,471	$53,057	$54,081
Wyoming Electric	9,585	9,837	29,283	29,031
Colorado Electric	27,460	27,586	73,721	74,303
Total Residential	54,546	55,894	156,061	157,415
Commercial:				
South Dakota Electric	25,714	27,156	73,026	76,330
Wyoming Electric	16,306	16,991	47,818	48,550
Colorado Electric	25,907	24,649	72,782	70,368
Total Commercial	67,927	68,796	193,626	195,248
Industrial:				
South Dakota Electric	8,275	8,364	24,540	25,122
Wyoming Electric	11,904	9,493	32,353	26,657
Colorado Electric	9,870	10,885	28,917	32,041
Total Industrial	30,049	28,742	85,810	83,820
Municipal:				
South Dakota Electric	1,053	1,024	2,844	2,741
Wyoming Electric	543	552	1,606	1,650
Colorado Electric	3,299	3,173	8,879	9,191
Total Municipal	4,895	4,749	13,329	13,582
Total Retail Revenue - Electric	157,417	158,181	448,826	450,065
Contract Wholesale:				
Total Contract Wholesale - South Dakota Electric	4,596	4,563	12,717	13,962
Off-system Wholesale:				
South Dakota Electric	3,984	5,417	11,304	18,718
Wyoming Electric	924	854	3,777	3,807
Colorado Electric	522	515	1,229	1,017
Total Off-system Wholesale	5,430	6,786	16,310	23,542
Other Revenue:				
South Dakota Electric	5,605	7,116	19,901	19,478
Wyoming Electric	325	659	1,435	1,700
Colorado Electric	1,128	1,285	4,069	3,783
Total Other Revenue	7,058	9,060	25,405	24,961
Total Revenue - Electric	$174,501	$178,590	$503,258	$512,530

Quantities Generated and Purchased (in MWh)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Generated —				
Coal-fired:				
South Dakota Electric [a]	401,231	389,784	1,054,264	1,166,381
Wyoming Electric [b]	188,739	142,887	548,513	517,685
Total Coal-fired	589,970	532,671	1,602,777	1,684,066
Natural Gas and Oil:				
South Dakota Electric [a]	41,654	37,721	96,649	57,482
Wyoming Electric [a]	23,874	24,331	58,944	34,881
Colorado Electric	64,507	49,343	128,397	87,090
Total Natural Gas and Oil	130,035	111,395	283,990	179,453
Wind:				