BLACK HILLS CORP /SD/
Form 10-Q
August 05, 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 June 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 July 31, 2016	
Common stock, $1.00 par value	52,324,123	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
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

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 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)	A program our utility subsidiaries submitted applications for with respective state utility regulators in Iowa, Kansas, Nebraska, South Dakota, Colorado and Wyoming, seeking approval for a 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)
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
Peak View Wind Project	$109 million 60 MW wind generating project for Colorado Electric, adjacent to Busch Ranch wind farm
PPA	Power Purchase Agreement
Recourse Leverage Ratio	Any indebtedness outstanding at such time, divided by Capital at such time. Capital being consolidated net-worth plus all recourse indebtedness.
Revolving Credit Facility	Our $500 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2020.
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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	(in thousands, except per share amounts)			
Revenue	$325,441	$272,254	$775,400	$714,241
Operating expenses:				
Fuel, purchased power and cost of natural gas sold	84,489	73,824	256,345	279,151
Operations and maintenance	112,541	90,410	219,603	183,544
Depreciation, depletion and amortization	47,305	40,051	91,712	79,053
Taxes - property, production and severance	12,760	11,377	24,877	23,313
Impairment of long-lived assets	25,497	94,484	39,993	116,520
Other operating expenses	7,551	966	33,982	1,018
Total operating expenses	290,143	311,112	666,512	682,599
Operating income (loss)	35,298	(38,858)	108,888	31,642
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(34,609)	(19,545)	(66,683)	(39,455)
Allowance for funds used during construction - borrowed	754	207	1,255	365
Capitalized interest	268	481	503	757
Interest income	946	301	1,601	749
Allowance for funds used during construction - equity	982	77	1,689	133
Other income (expense), net	(47)	395	641	726
Total other income (expense), net	(31,706)	(18,084)	(60,994)	(36,725)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	3,592	(56,942)	47,894	(5,083)
Equity in earnings (loss) of unconsolidated subsidiaries	—	(47)	—	(344)
Impairment of equity investments	—	(5,170)	—	(5,170)
Income tax benefit (expense)	(309)	20,317	(4,561)	2,605
Net income (loss)	3,283	(41,842)	43,333	(7,992)
Net income attributable to noncontrolling interest	(2,614)	—	(2,662)	—
Net income (loss) available for common stock	$669	$(41,842)	$40,671	$(7,992)
Earnings (loss) per share of common stock:				
Earnings (loss) per share, Basic	$0.01	$(0.94)	$0.79	$(0.18)
Earnings (loss) per share, Diluted	$0.01	$(0.94)	$0.78	$(0.18)
Weighted average common shares outstanding:				
Basic	51,514	44,617	51,279	44,579
Diluted	52,986	44,617	52,454	44,579

Dividends declared per share of common stock	$0.420	$0.405	$0.840	$0.810

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Net income (loss)	$3,283	$(41,842)	$43,333	$(7,992)
Other comprehensive income (loss), net of tax:				
Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of $5,346 and $1,171 for the three months ended 2016 and 2015 and $10,865 and $128 for the six months ended 2016 and 2015, respectively)	(9,720)	(1,966)	(20,066)	(130)
Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $882 and $735 for the three months ended 2016 and 2015 and $1,884 and $1,989 for the six months ended 2016 and 2015, respectively)	(1,504)	(1,261)	(3,214)	(2,502)
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 $15 for the six 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 $38 and $38 for the six months ended 2016 and 2015, respectively)	(36)	(36)	(72)	(72)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(173) and $(247) for the three months ended 2016 and 2015 and $(346) and $(494) for the six months ended 2016 and 2015, respectively)	321	458	643	916
Other comprehensive income (loss), net of tax	(10,939)	(2,805)	(22,709)	(1,815)
Comprehensive income (loss)	(7,656)	(44,647)	20,624	(9,807)
Less: comprehensive income attributable to noncontrolling interest	(2,614)	—	(2,662)	—
Comprehensive income (loss) available for common stock	$(10,270)	$(44,647)	$17,962	$(9,807)

See Note 15 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 June 30, 2016	December 31, 2015	June 30, 2015
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$116,805	$456,535	$87,210
Restricted cash and equivalents	1,975	1,697	2,316
Accounts receivable, net	150,227	147,486	123,661
Materials, supplies and fuel	85,189	86,943	73,749
Derivative assets, current	4,030	—	—
Income tax receivable, net	—	368	770
Deferred income tax assets, net, current	—	—	52,394
Regulatory assets, current	54,856	57,359	47,157
Other current assets	30,652	71,763	51,315
Total current assets	443,734	822,151	438,572
Investments	12,363	11,985	12,098
Property, plant and equipment	6,209,816	4,976,778	4,726,478
Less: accumulated depreciation and depletion	(1,819,886)	(1,717,684)	(1,522,969)
Total property, plant and equipment, net	4,389,930	3,259,094	3,203,509
Other assets:			
Goodwill	1,303,453	359,759	353,396
Intangible assets, net	9,164	3,380	3,211
Regulatory assets, non-current	220,556	175,125	180,815
Derivative assets, non-current	226	3,441	—
Other assets, non-current	15,438	7,382	17,313
Total other assets, non-current	1,548,837	549,087	554,735
TOTAL ASSETS	$6,394,864	$4,642,317	$4,208,914

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 June 30, 2016	December 31, 2015	June 30, 2015
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$170,149	$105,468	$78,021
Accrued liabilities	218,250	232,061	160,528
Derivative liabilities, current	28,855	2,835	3,289
Accrued income taxes, net	10,624	—	—
Regulatory liabilities, current	34,275	4,865	10,910
Notes payable	75,000	76,800	105,760
Current maturities of long-term debt	930,743	—	—
Total current liabilities	1,467,896	422,029	358,508
Long-term debt	2,221,347	1,853,682	1,556,370
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	530,746	450,579	510,435
Derivative liabilities, non-current	231	156	1,433
Regulatory liabilities, non-current	195,166	148,176	150,835
Benefit plan liabilities	173,347	146,459	165,791
Other deferred credits and other liabilities	122,015	155,369	154,656
Total deferred credits and other liabilities	1,021,505	900,739	983,150
Commitments and contingencies (See Notes 9, 10, 11, 17, 18)			
Redeemable noncontrolling interest	4,171	—	—
Equity:			
Stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 52,299,075; 51,231,861; and 44,871,771 shares, respectively	52,299	51,232	44,872
Additional paid-in capital	1,072,927	953,044	751,679
Retained earnings	469,940	472,534	532,965
Treasury stock, at cost – 18,900; 39,720; and 35,855 shares, respectively	(975)	(1,888)	(1,771)
Accumulated other comprehensive income (loss)	(31,764)	(9,055)	(16,859)
Total stockholders' equity	1,562,427	1,465,867	1,310,886
Noncontrolling interest	117,518	—	—
Total equity	1,679,945	1,465,867	1,310,886
TOTAL LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY	$6,394,864	$4,642,317	$4,208,914

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)	Six Months Ended June 30,	
	2016	2015
Operating activities:	(in thousands)	
Net income (loss) available for common stock	$40,671	$(7,992)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	91,712	79,053
Deferred financing cost amortization	2,857	1,119
Impairment of long-lived assets	39,993	121,690
Derivative fair value adjustments	(4,617)	(5,249)
Stock compensation	7,054	3,098
Deferred income taxes	32,606	(6,277)
Employee benefit plans	7,782	10,467
Other adjustments, net	(1,715)	3,720
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	17,722	20,218
Accounts receivable, unbilled revenues and other operating assets	82,361	63,172
Accounts payable and other operating liabilities	(85,423)	(66,294)
Regulatory assets - current	1,862	27,178
Regulatory liabilities - current	2,994	7,290
Contributions to defined benefit pension plans	(10,200)	—
Other operating activities, net	(2,884)	3,215
Net cash provided by (used in) operating activities	222,775	254,408
Investing activities:		
Property, plant and equipment additions	(199,854)	(206,472)
Acquisition, net of long term debt assumed	(1,124,238)	—
Other investing activities	(649)	(652)
Net cash provided by (used in) investing activities	(1,324,741)	(207,124)
Financing activities:		
Dividends paid on common stock	(43,265)	(36,292)
Common stock issued	57,490	1,702
Sale of noncontrolling interest	216,370	—
Short-term borrowings - issuances	208,100	154,460
Short-term borrowings - repayments	(209,900)	(123,700)
Long-term debt - issuances	574,672	300,000
Long-term debt - repayments	(41,436)	(275,000)
Other financing activities	205	(2,462)
Net cash provided by (used in) financing activities	762,236	18,708
Net change in cash and cash equivalents	(339,730)	65,992
Cash and cash equivalents, beginning of period	456,535	21,218
Cash and cash equivalents, end of period	$116,805	$87,210

See Note 16 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 2015 we began transitioning the Oil and Gas business to support utilities through a Cost of Service Gas Program. The following changes have been made to our Condensed Consolidated Statements of Income to reflect combined operations and maintenance expenses, rather than by business group as previously reported, for the three and six months ended June 30, 2015, respectively:

	For the Three Months Ended June 30, 2015			For the Six Months Ended June 30, 2015		
(in thousands)	As Previously Reported	Presentation Reclassification	As Currently Reported	As Previously Reported	Presentation Reclassification	As Currently Reported
Utilities - operations and maintenance	$67,264	$ (67,264)	$—	$138,348	$ (138,348)	$—
Non-regulated energy operations and maintenance	$23,146	$ (23,146)	$—	$45,196	$ (45,196)	$—
Operations and maintenance	$—	$ 90,410	$90,410	$—	$ 183,544	$183,544

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 six months ending June 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 June 30, 2016, December 31, 2015, and June 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 six months ended June 30, 2016 and June 30, 2015, and our financial condition as of June 30, 2016, December 31, 2015, and June 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. Our significant assumptions and estimates can include, but are not limited to, the cash flows that an acquired entity is expected to generate in the future, the appropriate weighted-average cost of capital, and the savings expected to be derived from the business combination. 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 net income (loss) of those subsidiaries are reported separately in the consolidated statements of income and comprehensive income. See Note 11 for additional detail on Noncontrolling Interests.

Recently Issued and Adopted Accounting Standards

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. The Company is currently assessing the impact that adoption of ASU 2016-09 will have on its 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. We are currently assessing 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 June 30, 2016, we have 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 $11 million in the Condensed Consolidated Balance Sheets as of

December 31, 2015, and June 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 the Company’s 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 acquisition costs of approximately $6.3 million and $31 million, respectively, in the three and six months ended June 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 $0.7 million of acquisition costs recorded in the three and six months ended June 30, 2015.

Our consolidated operating results for the three and six months ended June 30, 2016 include revenues of $70 million and $145 million, respectively, and net income (loss) of $(3.0) million and $4.6 million, respectively, attributable to SourceGas for the period from February 12 through June 30, 2016. SourceGas is 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 $944 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. During the three months ended June 30, 2016, we decreased goodwill by $2.7 million, reflecting the working capital adjustment received of $11 million and changes in valuation estimates for property, plant and equipment, long-term debt and regulatory liabilities. Approximately $214 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	$111,629
Property, plant & equipment, net	1,047,584
Goodwill	943,694
Deferred charges and other assets, excluding goodwill	132,534
Current liabilities	(167,613)
Long-term debt	(764,337)
Deferred credits and other liabilities	(179,253)
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. 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 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 the net buyout costs associated with the contract termination to create a regulatory asset and recover the majority of costs over a five year period. This liability is included with Current liabilities of the preliminary purchase price allocation.

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 six months ended June 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands, except per share amounts)			
Revenue	$325,441	$347,085	$854,362	$975,549
Net income (loss) available for common stock	$4,658	$(49,751)	$72,978	$306
Earnings (loss) per share, Basic	$0.09	$(0.98)	$1.42	$0.01
Earnings (loss) per share, Diluted	$0.09	$(0.98)	$1.39	$0.01

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 six months ended June 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 six months ended June 30, 2016 reflect unfavorable weather impacts resulting in lower gas pricing 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 is provided a 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.

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(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 June 30, 2016	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$ 158,560	$ 2,921	$ 19,229
Gas	153,767	(1,806)	987
Power Generation [e]	1,546	20,168	5,683
Mining	3,922	7,125	724
Oil and Gas [a]	7,646	—	(19,424)
Corporate activities [c]	—	—	(6,530)
Inter-company eliminations	—	(28,408)	—
Total	$ 325,441	$ —	$ 669

Three Months Ended June 30, 2015	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric [d]	$ 161,514	$ 2,509	17,632
Gas [d]	87,663	—	3,235
Power Generation	1,706	20,603	7,549
Mining	9,052	7,673	3,049
Oil and Gas [a] [b]	12,319	—	(71,195)
Corporate activities	—	—	(2,112)
Inter-company eliminations	—	(30,785)	—
Total	$ 272,254	$ —	$ (41,842)

Six Months Ended June 30, 2016	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$ 322,091	$ 6,666	$ 38,444
Gas	422,434	—	32,914
Power Generation [e]	3,398	41,624	14,265

Mining	11,456	15,873	3,662
Oil and Gas [a]	16,021	—	(26,448)
Corporate activities [c]	—	—	(22,166)
Inter-company eliminations	—	(64,163)	—
Total	$ 775,400	$ —	$ 40,671

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Six Months Ended June 30, 2015	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric [d]	328,007	5,933	35,185
Gas [d]	341,795	—	26,823
Power Generation	3,659	41,324	15,694
Mining	17,194	15,465	6,059
Oil and Gas [a] [b]	23,586	—	(90,310)
Corporate activities	—	—	(1,443)
Inter-company eliminations	—	(62,722)	—
Total	$714,241	$ —	$(7,992)

(a) Net income (loss) available for common stock for the three and six months ended June 30, 2016 and June 30, 2015 includes non-cash after-tax impairments of oil and gas properties of $16 million and $25 million and $63 million and $77 million, respectively. See Note 19 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b) Net income (loss) available for common stock for the three and six months ended June 30, 2015 included a non-cash after-tax impairment to equity investments of $3.4 million. See Note 19 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 six months ended June 30, 2016 included incremental, non-recurring acquisition costs, net of tax of $4.1 million and $20 million, respectively, and after-tax internal labor costs attributable to the acquisition of $2.0 million and $5.7 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 six months ended June 30, 2015 have been reclassified from the Electric Utility segment to the Gas Utility segment. Revenue of $8.2 million and $25 million, respectively, and Net income of $0.1 million and $1.4 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 $2.6 million for the three and six months ended June 30, 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:	June 30, 2016	December 31, 2015	June 30, 2015
Segment:			
Electric [a] [b]	$2,777,142	$2,720,004	$2,732,663
Gas [b]	3,142,293	999,778	920,624
Power Generation [a]	80,360	60,864	72,270
Mining	71,319	76,357	76,079
Oil and Gas [c]	171,228	208,956	275,068
Corporate activities [d]	152,522	576,358	132,210
Total assets	$6,394,864	$4,642,317	$4,208,914

(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 six months ended June 30, 2015 have been reclassified from the Electric Utility segment to the Gas Utility segment. Assets of $135 million and $119 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 June 30, 2015.

(c) As a result of continued low commodity prices and the transition of Oil and Gas to support Cost of Service Gas programs, we recorded non-cash impairments of $40 million for the six months ended June 30, 2016, $250 million for the year ended December 31, 2015, and $117 million for the six months ended June 30, 2015. See Note 19 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.

(4) ACCOUNTS RECEIVABLE

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

June 30, 2016	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 40,991	$ 34,174	$ (716)	$ 74,449
Gas Utilities	47,600	23,124	(2,997)	67,727
Power Generation	1,229	—	—	1,229
Mining	1,114	—	—	1,114
Oil and Gas	3,094	—	(13)	3,081
Corporate	2,627	—	—	2,627
Total	$ 96,655	$ 57,298	$ (3,726)	$ 150,227

December 31, 2015	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	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

June 30, 2015	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities (a)	$ 44,126	$ 32,660	$ (746)	$ 76,040
Gas Utilities (a)	27,890	10,259	(1,198)	36,951
Power Generation	1,199	—	—	1,199
Mining	3,402	—	—	3,402
Oil and Gas	5,099	—	(13)	5,086
Corporate	983	—	—	983
Total	$ 82,699	$ 42,919	$ (1,957)	$ 123,661

(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 $3.1 million as of December 31, 2015 and June 30, 2015, respectively, previously reported in the Electric Utility segment is now presented in the Gas Utility segment.

(5) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of June 30, 2016	As of December 31, 2015	As of June 30, 2015
Regulatory assets				
Deferred energy and fuel cost adjustments - current [a] [d]	1	$20,603	$24,751	$26,862
Deferred gas cost adjustments [a][d]	1	12,122	15,521	5,588
Gas price derivatives [a]	7	11,515	23,583	17,907
AFUDC [b]	45	13,879	12,870	12,321
Employee benefit plans [c] [e]	12	109,522	83,986	96,734
Environmental [a]	subject to approval	1,144	1,180	1,224
Asset retirement obligations [a]	44	505	457	3,242
Bond issue cost [a]	22	3,061	3,133	3,204
Renewable energy standard adjustment [b]	5	2,679	5,068	5,629
Flow through accounting [c]	35	31,554	29,722	27,861
Decommissioning costs [f]	10	18,399	18,310	14,845
Gas supply contract termination	5	28,385	—	—
Other regulatory assets [a]	15	22,044	13,903	12,555
		$275,412	$232,484	$227,972
Regulatory liabilities				
Deferred energy and gas costs [a] [d]	1	$32,868	$7,814	$16,114
Employee benefit plans [c] [e]	12	62,712	47,218	53,163
Cost of removal [a]	44	126,002	90,045	84,118
Other regulatory liabilities [c]	25	7,859	7,964	8,350
		$229,441	$153,041	$161,745

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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 $13 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.

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 for which there is no legal obligation for removal. The increase from the prior periods is due to cost of removal recorded with the SourceGas purchase price allocation. See Note 2 for additional details.

(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:

	June 30, 2016	December 31, 2015	June 30, 2015
Materials and supplies	$67,440	$ 55,726	$54,646
Fuel - Electric Utilities	4,659	5,567	6,644
Natural gas in storage held for distribution	13,090	25,650	12,459
Total materials, supplies and fuel	$85,189	$ 86,943	$73,749

(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	$250,487	$100,507	$ 8,765	359,759
Acquisition of SourceGas (a)	—	943,694	—	943,694
Ending balance at June 30, 2016	$250,487	$1,044,201	$ 8,765	$1,303,453

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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 December 31, 2015	$3,380
Additions, net (a)	6,225
Amortization expense	(441)
Intangible assets, net, ending balance at June 30, 2016	$9,164

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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) 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net income (loss) available for common stock	$669	$(41,842)	$40,671	$(7,992)
Weighted average shares - basic	51,514	44,617	51,279	44,579
Dilutive effect of:				
Equity Units [(a)]	1,362	—	1,068	—
Equity compensation	110	—	107	—
Weighted average shares - diluted [(b)]	52,986	44,617	52,454	44,579

(a) Calculated using the treasury stock method.

(b) Due to our net loss for the three and six months ended June 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, 83,613 and 101,146 equity compensation shares were excluded from the computations for the three and six months ended June 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Equity compensation	4	119	10	113
Anti-dilutive shares	4	119	10	113

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(9) NOTES PAYABLE

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

	June 30, 2016		December 31, 2015		June 30, 2015	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$75,000	$24,700	$76,800	$33,399	$105,760	$23,100

Revolving Credit Facility

On June 26, 2015, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through June 26, 2020. 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 the capacity of the facility to $750 million. 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 S&P and/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 June 30, 2016. A commitment fee is charged on the unused amount of the Revolving Credit Facility and was 0.175% based on our credit rating.

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, and we 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. The maximum Recourse Leverage Ratio returns to 0.65 to 1.00 on March 31, 2017. Additionally, covenants within Black Hills Gas Holdings financing agreements require Black Hills Gas Holdings to maintain a consolidated debt to capitalization ratio of no more than 0.75 to 1.00.

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

	As of June 30, 2016	Covenant Requirement
Recourse Leverage Ratio	69%	Less than 75%

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

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

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

	Interest Rate at June 30, 2016	June 30, 2016	December 31, 2015	June 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		(867)	—	—
Senior unsecured notes due November 30, 2023	4.25%	525,000	525,000	525,000
Unamortized discount on Senior unsecured notes due 2023		(1,754)	(1,890)	(2,027)
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		(243)	—	—
Corporate term loan due June 30, 2017 [(a)] [(b)]	1.38%	340,000	—	—
Corporate term loan due April 12, 2017 [(b)]	1.40%	260,000	300,000	300,000
Corporate term loan due June 7, 2021	2.32%	27,278	—	—
Total Corporate Debt		2,198,414	1,322,110	1,022,973
Gas Utilities				
Senior secured notes due September 29, 2019 [(a)] [(e)] [(f)]	3.98%	99,272	—	—
Senior unsecured notes due April 1, 2017 [(a)]	5.90%	325,000	—	—
Unamortized discount on Senior unsecured notes due 2017		(77)	—	—
		424,195	—	—
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		(97)	(99)	(101)
First Mortgage Bonds due November 20, 2037	6.67%	110,000	110,000	110,000
Industrial development revenue bonds due September 1, 2021 [(c)]	0.43%	7,000	7,000	7,000
Industrial development revenue bonds due March 1, 2027 [(c)]	0.43%	10,000	10,000	10,000
Series 94A Debt, variable rate due June 1, 2024 [(c)]	0.75%	2,855	2,855	2,855
Total Electric Utilities Debt		544,758	544,756	544,754
Total long-term debt		3,167,367	1,866,866	1,567,727
Less current maturities		930,743	—	—
Less deferred financing costs [(d)]		15,277	13,184	11,357
Long-term debt, net of current maturities		$2,221,347	$1,853,682	$1,556,370

(a) Long-term debt assumed with the SourceGas Acquisition.
(b) Variable interest rate, based on LIBOR plus a spread.
(c) Variable interest rate.
(d) Includes deferred financing costs associated with our Revolving Credit Facility of $1.5 million, $1.7 million and $1.9 million as of June 30, 2016, December 31, 2015 and June 30, 2015, respectively.
(e) Currently unsecured, required to be ratably secured if Black Hills Gas Holdings incurs other secured indebtedness.

(f) Includes a $4.2 million fair value adjustment from the SourceGas purchase price allocation.

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

Year Ended:	
2016	$2,871
2017	$930,743
2018	$5,743
2019	$355,015
2020	$205,742
Thereafter	$1,670,291

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

Current Maturities of Long-Term Debt

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

Loan	Interest Rate	Current Maturities at June 30, 2016
Corporate		
Corporate term loan due April 12, 2017	1.40%	$ 260,000
Corporate term loan due June 7, 2021 [(a)]	2.32%	5,743
Corporate term loan due June 30, 2017	1.38%	340,000
		605,743
Gas Utilities		
Senior unsecured notes due April 1, 2017	5.90%	325,000
Current Maturities of Long-Term Debt		$ 930,743

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

Debt Transactions

In accordance with regulatory orders related to the early termination and settlement of the gas supply contract described in footnote 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%, 10-year senior notes due 2026, and $250 million of 2.50%, 3-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 is LIBOR plus a margin of 0.875%.

(11) EQUITY

A summary of the changes in equity is as follows:

Six Months Ended June 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)	40,671	2,632	43,303
Other comprehensive income (loss)	(22,709)	—	(22,709)
Dividends on common stock	(43,270)	—	(43,270)
Share-based compensation	2,192	—	2,192
Issuance of common stock	55,802	—	55,802
Dividend reinvestment and stock purchase plan	1,478	—	1,478
Other stock transactions	(20)	—	(20)
Sale of noncontrolling interest	62,416	114,886	177,302
Balance at June 30, 2016	$ 1,562,427	$ 117,518	$ 1,679,945

Six Months Ended June 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)	(7,992)	—	(7,992)
Other comprehensive income (loss)	(1,815)	—	(1,815)
Dividends on common stock	(36,292)	—	(36,292)
Share-based compensation	1,601	—	1,601
Issuance of common stock	—	—	—
Dividend reinvestment and stock purchase plan	1,516	—	1,516
Other stock transactions	(16)	—	(16)
Balance at June 30, 2015	$ 1,310,886	$ —	$ 1,310,886

At-the-Market Equity Offering Program

On March 18, 2016, we implemented an at-the-market 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 June 30, 2016, we sold 809,649 common shares for $49 million, net of $0.5 million in commissions under the ATM equity offering program. Through June 30, 2016, we have sold and issued an aggregate of 930,649 shares of common stock under the ATM equity offering program for $56 million, net of $0.6 million in commissions. Additionally, 46,576 shares for net proceeds of $2.9 million have been sold, but were not settled and are not considered issued and outstanding as of June 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 AIA Energy North America LLC. 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 a partial sale of a subsidiary in which control is maintained and the subsidiary continues to be consolidated, be recorded as an equity transaction, 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. 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:

	June 30, 2016	December 31, 2015	June 30, 2015
	(in thousands)		
Assets			
Current assets	$12,681	$ —	$ —
Property, plant and equipment of variable interest entities, net	$224,128	$ —	$ —
Liabilities			
Current liabilities	$4,174	$ —	$ —

(12) 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 and anticipated future refinancings.

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 13.

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 and swaps 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:

	June 30, 2016		December 31, 2015		June 30, 2015	
	Crude Oil Futures	Natural Gas Futures and Swaps	Crude Oil Futures	Natural Gas Futures and Swaps	Crude Oil Futures	Natural Gas Futures and Swaps
Notional [(a)]	210,000	2,530,000	198,000	4,392,500	276,000	4,187,500
Maximum terms in months [(b)]	30	18	24	24	18	18

(a) Crude oil in Bbls, natural gas in MMBtus.

(b) Term reflects the maximum forward period hedged.

Based on June 30, 2016 prices, a $2.7 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:

	June 30, 2016		December 31, 2015		June 30, 2015	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	18,080,000	54	20,580,000	60	17,270,000	66
Natural gas options purchased	3,770,000	20	2,620,000	3	3,980,000	9
Natural gas basis swaps purchased	15,320,000	54	18,150,000	60	14,445,000	54
Natural gas fixed for float swaps, net[(b)]	5,029,500	23	—	0	—	0
Natural gas physical commitments, net	1,666,800	9	—	0	—	0

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(a) Term reflects the maximum forward period hedged.

(b) 2,974,500 MMBtus were designated as cash flow hedges for the natural gas fixed for float swaps purchased.

Financing Activities

We entered into pay fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations and anticipated debt refinancings. 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:

	June 30, 2016			December 31, 2015		June 30, 2015
	Interest Rate Swaps [(a)]	Interest Rate Swaps [(a)]	Interest Rate Swaps [(b)]	Interest Rate Swaps [(a)]	Interest Rate Swaps [(b)]	Interest Rate Swaps [(b)]
Notional	$150,000	$250,000	$75,000	$250,000	$75,000	$75,000

Weighted average fixed interest rate	2.09 %	2.29 %	4.97 %	2.29 %	4.97 %	4.97 %
Maximum terms in years	0.83	0.83	0.50	1.33	1.00	1.50
Derivative assets, non-current	$—	$—	$—	$3,441	$—	$—
Derivative liabilities, current	$8,553	$18,500	$1,505	$—	$2,835	$3,289
Derivative liabilities, non-current	$—	$—	$—	$—	$156	$1,433

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(a) These swaps are designated as cash flow hedges of anticipated debt refinancings.

(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.

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Based on June 30, 2016 market interest rates and balances related to our interest rate swaps, a loss of approximately $29 million 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 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 June 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	$ (12,614)	Interest expense	$ 840	Interest expense	$ —
Commodity derivatives	(2,847)	Revenue	(3,287)	Revenue	—
Commodity derivatives	395	Fuel, purchased power and cost of natural gas sold	61	Fuel, purchased power and cost of natural gas sold	—
Total	$ (15,066)		$ (2,386)		$ —

Three Months Ended June 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	$ (892)	Interest expense	$ (1,670)	Interest expense	$ —
Commodity derivatives	(2,245)	Revenue	3,666	Revenue	—
Total	$ (3,137)		$ 1,996		$ —

Six Months Ended June 30, 2016

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative	Location of Reclassifications from AOCI into Income	Amount of (Gain)/Loss Reclassified from AOCI into Income	Location of Gain/(Loss) Recognized in Income on Derivative	Amount of Gain/(Loss) Recognized in

	(Effective Portion)			(Settlements)	(Ineffective Portion)	Income on Derivative (Ineffective Portion)
Interest rate swaps	$ (30,665)	Interest expense	$ 1,690		Interest expense	$ —
Commodity derivatives	(1,039)	Revenue	(6,939)		Revenue	—
Commodity derivatives	773	Fuel, purchased power and cost of natural gas sold	151		Fuel, purchased power and cost of natural gas sold	—
Total	$ (30,931)		$ (5,098)			$ —

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Six Months Ended June 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	$ (1,778)	Interest expense	$ (3,107)	Interest expense	$ —
Commodity derivatives	1,520	Revenue	7,598	Revenue	—
Total	$ (258)		$ 4,491		$ —

(13) 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, 8, 9 and 10 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 and basis swaps. 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.

	As of June 30, 2016				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Futures -- Oil	—	1,950	—	(816)	1,134
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	798	—	(334)	464
Commodity derivatives — Utilities	—	6,833	—	(4,175)	2,658
Interest Rate Swaps	—	—	—	—	—
Total	$ —	$9,581	$ —	$ (5,325)	$4,256
Liabilities:					
Commodity derivatives — Oil and Gas					
Futures -- Oil	—	157	—	—	157
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	71	—	—	71
Commodity derivatives — Utilities	—	14,727	—	(14,427)	300
Interest rate swaps	—	28,558	—	—	28,558
Total	$ —	$43,513	$ —	$ (14,427)	$29,086

	As of December 31, 2015				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Futures -- Oil	—	6,309	—	(6,309)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	4,335	—	(4,335)	—
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					
Futures -- Oil	—	—	—	—	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- 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 June 30, 2015				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Futures -- Oil	—	5,178	—	(5,178)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	4,372	—	(4,372)	—
Commodity derivatives — Utilities	—	2,577	—	(2,577)	—
Interest Rate Swaps	—	—	—	—	—
Total	$ —	$12,127	$ —	$ (12,127)	$—
Liabilities:					
Commodity derivatives — Oil and Gas					
Futures -- Oil	—	112	—	(112)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	498	—	(498)	—
Commodity derivatives — Utilities	—	18,758	—	(18,758)	—
Interest rate swaps	—	4,722	—	—	4,722
Total	$ —	$24,090	$ —	$ (19,368)	$4,722

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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 June 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 12 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 June 30, 2016

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 2,549	$ —
Commodity derivatives	Derivative assets — non-current	81	—
Interest rate swaps	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	44
Commodity derivatives	Derivative liabilities — non-current	—	226
Interest rate swaps	Derivative liabilities — current	—	28,558
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives designated as hedges		$ 2,630	$ 28,828
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 1,481	$ —
Commodity derivatives	Derivative assets — non-current	145	—
Commodity derivatives	Derivative liabilities — current	—	254
Commodity derivatives	Derivative liabilities — non-current	—	4
Total derivatives not designated as hedges		$ 1,626	$ 258

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 June 30, 2015

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 6,931	$ —
Commodity derivatives	Derivative assets — non-current	2,619	—
Commodity derivatives	Derivative liabilities — current	—	493
Commodity derivatives	Derivative liabilities — non-current	—	117
Interest rate swaps	Derivative liabilities — current	—	3,289
Interest rate swaps	Derivative liabilities — non-current	—	1,433
Total derivatives designated as hedges		$ 9,550	$ 5,332
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ —	$ —
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	5,156
Commodity derivatives	Derivative liabilities — non-current	—	11,025
Total derivatives not designated as hedges		$ —	$ 16,181

(14) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 13, were as follows (in thousands) as of:

	June 30, 2016		December 31, 2015		June 30, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$116,805	$116,805	$456,535	$456,535	$87,210	$87,210
Restricted cash and equivalents [(a)]	$1,975	$1,975	$1,697	$1,697	$2,316	$2,316
Notes payable [(a)]	$75,000	$75,000	$76,800	$76,800	$105,760	$105,760
Long-term debt, including current maturities, net of deferred financing costs [(b)]	$3,152,090	$3,427,587	$1,853,682	$1,992,274	$1,556,370	$1,700,487

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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.

(15) 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		Six Months Ended	
		June 30, 2016	June 30, 2015	June 30, 2016	June 30, 2015
(Gains) losses on cash flow hedges:					
Interest rate swaps	Interest expense	$840	$1,670	$1,690	$3,107
Commodity contracts	Revenue	(3,287)	(3,666)	(6,939)	(7,598)
Commodity contracts	Fuel, purchased power and cost of natural gas sold	61	—	151	—
		(2,386)	(1,996)	(5,098)	(4,491)
Income tax	Income tax (benefit) expense	882	735	1,884	1,989
Reclassification adjustments related to cash flow hedges, net of tax		$(1,504)	$(1,261)	$(3,214)	$(2,502)
Amortization of defined benefit plans:					
Prior service cost	Operations and maintenance	$(55)	$(55)	$(110)	$(110)
Actuarial gain (loss)	Operations and maintenance	494	705	988	1,410
		439	650	878	1,300
Income tax	Income tax (benefit) expense	(154)	(228)	(307)	(456)
Reclassification adjustments related to defined benefit plans, net of tax		$285	$422	$571	$844

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

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Total
Balance as of December 31, 2014	$ 5,093	$ (20,137)	$ (15,044)
Other comprehensive income (loss), net of tax	595	395	990
Balance as of March 31, 2015	5,688	(19,742)	(14,054)
Other comprehensive income (loss), net of tax	422	(3,227)	(2,805)
Balance as of June 30, 2015	$ 6,110	$ (22,969)	$ (16,859)
Balance as of December 31, 2015	$ 6,725	$ (15,780)	$ (9,055)
Other comprehensive income (loss), net of tax	(12,056)	286	(11,770)
Balance as of March 31, 2016	$ (5,331)	$ (15,494)	$ (20,825)
Other comprehensive income (loss), net of tax	(11,224)	285	(10,939)
Balance as of June 30, 2016	$ (16,555)	$ (15,209)	$ (31,764)

(16) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Six months ended	June 30, 2016	June 30, 2015
	(in thousands)	
Non-cash investing and financing activities—		
Property, plant and equipment acquired with accrued liabilities	$ 52,917	$ 36,661
Cash (paid) refunded during the period —		
Interest (net of amounts capitalized)	$ (48,139)	$ (37,698)
Income taxes, net	$ (1,162)	$ (1,202)

(17) 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 Sheet 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

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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 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Service cost	$2,078	$1,494	$4,156	$2,988
Interest cost	3,936	3,880	7,872	7,760
Expected return on plan assets	(5,766)	(4,867)	(11,531)	(9,734)
Prior service cost	15	15	30	30
Net loss (gain)	1,793	2,759	3,586	5,518
Net periodic benefit cost	$2,056	$3,281	$4,113	$6,562

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Service cost	$467	$464	$934	$928
Interest cost	485	450	970	900
Expected return on plan assets	(70)	(33)	(140)	(66)
Prior service cost (benefit)	(107)	(107)	(214)	(214)
Net loss (gain)	84	102	168	204
Net periodic benefit cost	$859	$876	$1,718	$1,752

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Service cost	$878	$392	$907	$883
Interest cost	315	364	629	728
Prior service cost	1	1	1	2
Net loss (gain)	207	270	414	540
Net periodic benefit cost	$1,401	$1,027	$1,951	$2,153

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 June 30, 2016	Six Months Ended June 30, 2016	Anticipated for 2016	Anticipated for 2017
$ 10,200	$ 10,200	$ —	$ 10,200

Defined Benefit Pension Plans								
Non-pension Defined Benefit Postretirement Healthcare Plans	$	1,192	$	2,384	$	2,384	$	4,744
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$	392	$	784	$	784	$	1,627

(18) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2015 Annual Report on Form 10-K except for those described below and in Notes 2 and 21.

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	$29,411	$44,789	$44,434	$40,636	$40,636	$192,651	$392,557
Facilities and equipment	1,247	2,216	2,207	1,676	1,359	3,326	12,031
Total	$30,658	$47,005	$46,641	$42,312	$41,995	$195,977	$404,588

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 June 30, 2016, the long-term commitments to purchase physical quantities of natural gas under contracts indexed to the forward Northwest Wyoming Pool totaled 0.24 Bcf within one year, 1.20 Bcf within one to two years and 0.97 Bcf in the third year. Purchases under these contracts totaled $1.7 million for the six months ended June 30, 2016 which are 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 June 30, 2016, the balance of BHC's guarantee was approximately $47 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 June 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

June 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 June 30, 2016, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

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(19) 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 have 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 six months ended June 30, 2016 and June 30, 2015.

- During the first quarter of 2016, we recorded a $14 million pre-tax non-cash impairment of oil and gas assets included in our Oil and Gas segment. During the second quarter of 2016, we recorded an $11 million pre-tax non-cash impairment of oil and gas assets. At June 30, 2016, for natural gas, the average NYMEX price was $2.24 per Mcf, adjusted to $1.01 per Mcf at the wellhead; for crude oil, the average NYMEX price was $43.12 per barrel, adjusted to $37.19 per barrel at the wellhead.

- During the first quarter of 2015, we recorded a $22 million pre-tax non-cash impairment of oil and gas assets included in our Oil and Gas segment. During the second quarter of 2015, we recorded a $94 million pre-tax non-cash impairment of oil and gas assets. At June 30, 2015, for natural gas, the average NYMEX price was $3.39 per Mcf, adjusted to $2.14 per Mcf at the wellhead; for crude oil, the average NYMEX price was $71.68 per barrel, adjusted to $63.76 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.

(20) INCOME TAXES

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

Tax (benefit) expense	Three Months Ended June 30, 2016	2015
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect) [(a)]	16.9	2.6
Percentage depletion in excess of cost	(5.9)	0.8
Accounting for uncertain tax positions adjustment	1.9	(0.5)
Noncontrolling interest [(b)]	(25.1)	—
Flow-through adjustments	(10.6)	1.0
Inter-period adjustment	1.7	(6.5)
AFUDC equity	(5.8)	0.3
Other tax differences	0.5	—
	8.6 %	32.7 %

(a) The increase in state income tax expense was due primarily to a change in projections, the impact of which was more pronounced in the current period due to significantly lower consolidated pre-tax net income.

(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.

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

Tax (benefit) expense	Six Months Ended June 30, 2016	2015
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect)	3.8	2.4
Percentage depletion in excess of cost [(c)]	(13.5)	9.5
Inter-period adjustment	(3.5)	(22.6)
Accounting for uncertain tax positions adjustment [(d)]	(10.4)	(11.9)
Noncontrolling interest	(1.9)	—
Transaction costs	2.3	—
Flow-through adjustments	(1.7)	9.5
Other tax differences	(0.6)	2.7
	9.5 %	24.6 %

(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.

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.

(21) ACCRUED LIABILITIES

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

	June 30, 2016	December 31, 2015	June 30, 2015
Accrued employee compensation, benefits and withholdings	$45,991	$43,342	$35,126
Accrued property taxes	33,295	32,393	26,820
Accrued payments related to litigation expenses and settlements	—	38,750	25,000
Customer deposits and prepayments	44,200	53,496	26,384
Accrued interest and contract adjustment payments	42,330	25,762	13,656
CIAC current portion [a]	20,211	14,745	—
Other (none of which is individually significant)	32,223	23,573	33,542
Total accrued liabilities	$218,250	$232,061	$160,528

(a) Prior to December 31, 2015, CIACs were classified as non-current liabilities.

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. In 2015, we began transitioning the Oil and Gas segment to focus primarily on activities supporting utility cost of service gas programs.

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, other than the Oil and Gas segment, and in 2015 we began transitioning the Oil and Gas business to focus primarily on activities supporting utility cost of service gas programs.

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 six months ended June 30, 2016 and 2015, and our financial condition as of June 30, 2016, December 31, 2015 and June 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 Electric Utilities Revenue, Gross Margin and Net Income by $8.2 million, $4.5 million and $0.1 million, respectively, for the three months ended June 30, 2015, and $24.7 million, $10.9 million and $1.5 million, respectively, for the six months ended June 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 82.

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 June 30, 2016 Compared to Three Months Ended June 30, 2015. Net income (loss) available for common stock for the three months ended June 30, 2016 was $0.7 million, or $0.01 per share, compared to Net income (loss) available for common stock of $(42) million, or $(0.94) per share, reported for the same period in 2015. The Net income (loss) available for common stock for the three months ended June 30, 2016 increased over the same period in the prior year primarily due to a decrease in impairment charges on our oil and gas properties. Net income (loss) available for common stock for the three months ended June 30, 2016 included non-cash after-tax impairments of oil and gas properties of $16 million compared to a non-cash after-tax impairment of $63 million in the same period of the prior year. The Net income (loss) available for common stock for the three months ended June 30, 2016 is net of $2.6 million of net income attributable to noncontrolling interests and includes a loss of $(3.0) million from our acquired SourceGas utilities and after-tax SourceGas acquisition and transition related costs of $4.1 million. The Net income (loss) available for common stock for the three months ended June 30, 2015 included a non-cash after-tax impairment loss on an equity investment of $3.4 million.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015. Net income (loss) available for common stock for the six months ended June 30, 2016 was $41 million, or $0.78 per share, compared to Net income (loss) available for common stock of $(8) million, or $(0.18) per share, reported for the same period in 2015. The Net income (loss) available for common stock for the six months ended June 30, 2016, net of $2.6 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 $4.6 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 six months ended June 30, 2016 also included non-cash after-tax impairments of our oil and gas properties of $25 million and after-tax SourceGas acquisition and transition costs of $20 million. The Net income (loss) available for common stock for the six months ended June 30, 2015 included a non-cash after-tax ceiling test impairment of $77 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 June 30,			Six Months Ended June 30,		
	2016	2015	Variance	2016	2015	Variance
Revenue						
Revenue	$353,849	$303,039	$50,810	$839,563	$776,963	$62,600
Inter-company eliminations	(28,408)	(30,785)	2,377	(64,163)	(62,722)	(1,441)
	$325,441	$272,254	$53,187	$775,400	$714,241	$61,159
Net income (loss) available for common stock						
Electric Utilities	$19,229	$17,632	$1,597	$38,444	$35,185	$3,259
Gas Utilities	987	3,235	(2,248)	32,914	26,823	6,091
Power Generation	5,683	7,549	(1,866)	14,265	15,694	(1,429)
Mining	724	3,049	(2,325)	3,662	6,059	(2,397)
Oil and Gas [(a)] [(b)] [(c)]	(19,424)	(71,195)	51,771	(26,448)	(90,310)	63,862
	7,199	(39,730)	46,929	62,837	(6,549)	69,386
Corporate activities and eliminations [(d)] [(e)]	(6,530)	(2,112)	(4,418)	(22,166)	(1,443)	(20,723)
Net income (loss) available for common stock	$669	$(41,842)	$42,511	$40,671	$(7,992)	$48,663

(a) Net income (loss) available for common stock for the three and six months ended June 30, 2016 and June 30, 2015 included non-cash after-tax impairments of our oil and gas properties of $16 million and $25 million and $63 million and $77 million, respectively. See Note 19 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b) Net income (loss) available for common stock for the six months ended June 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 three and six months ended June 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 six months ended June 30, 2016 included incremental, non-recurring acquisition costs, after-tax of $4.1 million and $20 million, respectively, and after-tax internal labor costs attributable to the acquisition of $2.0 million and $5.7 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 six months ended June 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 hotter weather during the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015. Cooling degree days were 60% higher for the three and six months ended June 30, 2016, compared to the same periods in 2015. Cooling degree days for the three and six months ended June 30, 2016 were 68% higher than normal, compared to 4% 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 second quarter of 2016. Through June 30, 2016, approximately $49 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 $1.1 million and $2.3 million for the three and six months ended June 30, 2016, respectively.

- 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 is expected to be placed in service by the end of 2016.

- 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. The project is being built by Invenergy Wind Development Colorado LLC and is expected to be completed in the fourth quarter of 2016. 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. Through June 30, 2016, approximately $68 million was expended on the project.

Gas Utilities Segment

- Gas Utilities experienced milder weather during the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015. Heating degree days were 5% and 20% lower, respectively, for the three and six months ended June 30, 2016, compared to the same periods in 2015. Heating degree days for the three and six months ended June 30, 2016 were 10% and 11% lower than normal, respectively, compared to 9% lower than normal and comparable to normal for the same periods in 2015.

- On July 26, 2016, BHC announced a request for withdrawal of proceedings for its Cost of Service Gas application in Wyoming and will be requesting withdrawals of its Cost of Service Gas applications in 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 Colorado IPP 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 commodity prices for crude oil and natural gas for the three and six months ended June 30, 2016 compared to the same periods in 2015. The average hedged price received for natural gas decreased by 48% and 44%, respectively, for the three and six months ended June 30, 2016 compared to the same periods in 2015. The average hedged price received for oil decreased by 8% and 19%, respectively, for the three and six months ended June 30, 2016 compared to the same periods in 2015. Oil and Gas production volumes decreased 10% and 3%, respectively, for the three and six months ended June 30, 2016 compared to the same periods in 2015.

- 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. In the first and second quarters of 2016, our Oil and Gas segment recorded pre-tax, non-cash ceiling test impairments of $14 million and $11 million, respectively as a result of continued low commodity prices. Using our current reserves information, further ceiling test impairments are likely to occur in the third quarter of 2016 if commodity prices for crude oil and natural gas remain at current levels. 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 advanced our strategy to transition our Oil and Gas segment to support Cost of Service Gas programs.

Corporate Activities

- 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 20 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 at-the-market 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 June 30, 2016, we sold 809,649 common shares for $49 million, net of $0.5 million in commissions under the ATM equity offering program. Through June 30, 2016, we have sold and issued an aggregate of 930,649 shares of common stock under the ATM equity offering program for $56 million, net of $0.6 million in commissions. Additionally, 46,576 shares for net proceeds of $2.9 million have been sold, but were not settled and are not considered issued and outstanding as of June 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 purchase price 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 has maintained a negative outlook as BHC focuses on integrating the newly acquired SourceGas assets over the 12 months subsequent to closing, consummation of 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.

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- 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%, with a mandatory early termination date of April 12, 2017 to hedge the risks of interest rate movement between the hedge date and the expected pricing date for anticipated future long-term debt refinancings. This swap is accounted for as a cash flow hedge and any gain or loss is recorded in AOCI.

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 June 30,			Six Months Ended June 30,		
	2016	2015	Variance	2016	2015	Variance
	(in thousands)					
Revenue	$161,481	$164,023	$(2,542)	$328,757	$333,940	$(5,183)
Total fuel and purchased power	61,418	64,185	(2,767)	127,524	131,875	(4,351)
Gross margin	100,063	99,838	225	201,233	202,065	(832)
Operations and maintenance	38,879	40,734	(1,855)	78,204	81,971	(3,767)
Depreciation and amortization	20,473	19,954	519	41,731	40,222	1,509
Total operating expenses	59,352	60,688	(1,336)	119,935	122,193	(2,258)
Operating income	40,711	39,150	1,561	81,298	79,872	1,426
Interest expense, net	(12,131)	(12,961)	830	(24,630)	(26,215)	1,585
Other income (expense), net	838	167	671	1,493	241	1,252
Income tax benefit (expense)	(10,189)	(8,724)	(1,465)	(19,717)	(18,713)	(1,004)
Net income (loss)	$19,229	$17,632	$1,597	$38,444	$35,185	$3,259

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Revenue - Electric (in thousands)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Residential:				
South Dakota Electric	$16,241	$15,470	$35,556	$35,610
Wyoming Electric	9,241	8,929	19,698	19,194
Colorado Electric	23,148	22,147	46,261	46,717
Total Residential	48,630	46,546	101,515	101,521
Commercial:				
South Dakota Electric	23,723	24,433	47,312	49,174
Wyoming Electric	15,839	15,739	31,512	31,559
Colorado Electric	24,392	23,555	46,875	45,719
Total Commercial	63,954	63,727	125,699	126,452
Industrial:				
South Dakota Electric	7,764	8,459	16,265	16,758
Wyoming Electric	10,352	8,538	20,449	17,164
Colorado Electric	9,782	10,400	19,047	21,156
Total Industrial	27,898	27,397	55,761	55,078
Municipal:				
South Dakota Electric	960	859	1,791	1,717
Wyoming Electric	552	582	1,063	1,098
Colorado Electric	2,885	2,956	5,580	6,018
Total Municipal	4,397	4,397	8,434	8,833
Total Retail Revenue - Electric	144,879	142,067	291,409	291,884
Contract Wholesale:				
Total Contract Wholesale - South Dakota Electric	3,947	3,979	8,121	9,399
Off-system Wholesale:				
South Dakota Electric	2,734	6,666	7,320	13,301
Wyoming Electric	1,007	992	2,853	2,953
Colorado Electric	573	418	707	502
Total Off-system Wholesale	4,314	8,076	10,880	16,756
Other Revenue:				
South Dakota Electric	6,650	8,172	14,296	12,362
Wyoming Electric	520	566	1,110	1,041
Colorado Electric	1,171	1,163	2,941	2,498
Total Other Revenue	8,341	9,901	18,347	15,901
Total Revenue - Electric	$161,481	$164,023	$328,757	$333,940

	Three Months Ended June 30,		Six Months Ended June 30,	
Quantities Generated and Purchased (in MWh)	2016	2015	2016	2015
Generated —				
Coal-fired:				
South Dakota Electric [(a)]	265,032	399,763	653,033	776,597
Wyoming Electric	180,081	180,082	359,774	374,798
Total Coal-fired	445,113	579,845	1,012,807	1,151,395
Natural Gas and Oil:				
South Dakota Electric [(a)]	39,433	16,883	54,995	19,761
Wyoming Electric [(a)]	27,191	7,711	35,070	10,550
Colorado Electric	61,123	34,255	63,890	37,747
Total Natural Gas and Oil	127,747	58,849	153,955	68,058
Wind:				
Colorado Electric	10,588	10,177	23,649	19,268
Total Wind	10,588	10,177	23,649	19,268
Total Generated:				
South Dakota Electric	304,465	416,646	708,028	796,358
Wyoming Electric	207,272	187,793	394,844	385,348
Colorado Electric	71,711	44,432	87,539	57,015
Total Generated	583,448	648,871	1,190,411	1,238,721
Purchased —				
South Dakota Electric	315,379	350,892	655,069	789,335
Wyoming Electric	186,085	173,151	408,880	360,930
Colorado Electric	467,365	454,859	945,248	927,046
Total Purchased	968,829	978,902	2,009,197	2,077,311
Total Generated and Purchased:				
South Dakota Electric	619,844	767,538	1,363,097	1,585,693
Wyoming Electric	393,357	360,944	803,724	746,278
Colorado Electric	539,076	499,291	1,032,787	984,061
Total Generated and Purchased	1,552,277	1,627,773	3,199,608	3,316,032

(a) An increase in gas-fired generation from Cheyenne Prairie was due to lower coal fired generation driven by outages at the coal-fired Wyodak plant during the three and six months ended June 30, 2016.

Quantity Sold (in MWh)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Residential:				
South Dakota Electric	114,851	110,017	257,604	256,980
Wyoming Electric	59,587	58,169	127,900	125,668
Colorado Electric	144,318	136,767	293,346	293,981
Total Residential	318,756	304,953	678,850	676,629
Commercial:				
South Dakota Electric	190,207	189,889	379,095	384,967
Wyoming Electric	130,550	130,456	260,880	261,559
Colorado Electric	184,150	169,508	360,346	334,589
Total Commercial	504,907	489,853	1,000,321	981,115
Industrial:				
South Dakota Electric	102,620	102,494	210,641	214,353
Wyoming Electric	150,332	118,180	293,074	229,276
Colorado Electric [(a)]	113,454	110,925	212,943	229,032
Total Industrial	366,406	331,599	716,658	672,661
Municipal:				
South Dakota Electric	8,487	7,036	15,928	14,736
Wyoming Electric	2,102	2,174	4,647	4,724
Colorado Electric	30,026	28,808	56,609	56,921
Total Municipal	40,615	38,018	77,184	76,381
Total Retail Quantity Sold	1,230,684	1,164,423	2,473,013	2,406,786
Contract Wholesale:				
Total Contract Wholesale - South Dakota Electric [(b)]	56,087	64,896	119,540	149,167
Off-system Wholesale:				
South Dakota Electric	117,064	246,213	310,437	491,851
Wyoming Electric	21,253	24,662	58,746	73,534
Colorado Electric [(c)]	28,233	13,501	35,695	15,970
Total Off-system Wholesale	166,550	284,376	404,878	581,355
Total Quantity Sold:				
South Dakota Electric	589,316	720,545	1,293,245	1,512,054
Wyoming Electric	363,824	333,641	745,247	694,761
Colorado Electric	500,181	459,509	958,939	930,493
Total Quantity Sold	1,453,321	1,513,695	2,997,431	3,137,308
Other Uses, Losses or Generation, net [(d)]:				
South Dakota Electric	30,528	46,993	69,852	73,639
Wyoming Electric	29,533	27,303	58,477	51,517
Colorado Electric	38,895	39,782	73,848	53,568

Total Other Uses, Losses and Generation, net	98,956	114,078	202,177	178,724
Total Energy	1,552,277	1,627,773	3,199,608	3,316,032

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(a) Decrease was due to a planned outage at a large industrial customer during the first quarter of 2016.
(b) Decrease was driven by load requirements related to a unit-contingent PPA.
(c) Increase in 2016 generation was primarily driven by commodity prices that impacted power marketing sales.
(d) Includes company uses, line losses, and excess exchange production.

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Degree Days	Three Months Ended June 30, 2016			2015	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Heating Degree Days:					
South Dakota Electric	877	(13)%	(13)%	1,005	— %
Wyoming Electric	1,134	(15)%	(3)%	1,173	(2)%
Colorado Electric	516	(15)%	(17)%	624	2 %
Combined [(a)]	762	(14)%	(12)%	863	— %
Cooling Degree Days:					
South Dakota Electric	186	74 %	94%	96	(10)%
Wyoming Electric	102	100 %	65%	62	22 %
Colorado Electric	369	63 %	51%	245	8 %
Combined [(a)]	253	68 %	60%	158	4 %

Degree Days	Six Months Ended June 30, 2016			2015	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Heating Degree Days:					
South Dakota Electric	3,683	(13)%	(5)%	3,878	(8)%
Wyoming Electric	3,910	(12)%	2%	3,824	(9)%
Colorado Electric	2,801	(13)%	(7)%	3,022	(6)%
Combined [(a)]	3,323	(13)%	(4)%	3,473	(8)%
Cooling Degree Days:					
South Dakota Electric	186	74 %	94%	96	(10)%
Wyoming Electric	102	100 %	65%	62	22 %
Colorado Electric	369	63 %	51%	245	8 %
Combined [(a)]	253	68 %	60%	158	4 %

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

Electric Utilities Power Plant Availability	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Coal-fired plants [(a)]	75.1%	96.4%	84.5%	93.8%
Other plants	97.6%	93.7%	96.3%	94.7%
Total availability	89.5%	94.7%	92.0%	94.4%

(a) Decrease is due to a planned outage at Wygen III and an extended planned outage at Wyodak.

Results of Operations for the Electric Utilities for the Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015: Net income available for common stock for the Electric Utilities was $19 million for the three months ended June 30, 2016, compared to Net income available for common stock of $18 million for the three months ended June 30, 2015, as a result of:

Gross margin increased primarily due to a $1.3 million increase in residential margins driven by a 60 percent increase in cooling degree days compared to the same period in the prior year, and an increase in our construction and TCA rider margins of approximately $1.0 million. Partially offsetting these increases was a prior year increase in return on invested capital of $1.2 million from South Dakota Electric's rate case and a decrease of approximately $1.0 million primarily driven by lower demand pricing at our commercial and industrial customers.

Operations and maintenance decreased primarily due to lower employee costs of $1.0 million as a result of integration activities and transition expenses charged to the Corporate segment and a decrease in employee costs driven by a change in operating and capital expense allocations impacting the electric utilities as a result of integrating the acquired SourceGas utilities.

Depreciation and amortization increased primarily due to a higher asset base.

Interest expense, net decreased primarily due to higher AFUDC interest income driven by construction in process in the current period compared to the same period in the prior year.

Other income (expense), net increased primarily due to higher AFUDC equity in the current period compared to the same period in the prior year.

Income tax benefit (expense): The effective tax rate was comparable to the same period in the prior year.

Results of Operations for the Electric Utilities for the Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015: Net income available for common stock for the Electric Utilities was $38 million for the six months ended June 30, 2016, compared to Net income available for common stock of $35 million for the six months ended June 30, 2015, as a result of:

Gross margin decreased primarily due to a $2.1 million benefit in the prior year as a result of a one-time settlement agreement from the CPUC on our renewable energy standard adjustment related to the Busch Ranch wind farm, a prior year increase in return on invested capital of $1.2 million from South Dakota Electric’s rate case and a $1.0 million decrease in revenue from energy cost adjustments. Partially offsetting these decreases were favorable rider margins of $2.0 million driven primarily by our construction and TCA riders and an increase of $1.6 million in residential margins driven by favorable weather.

Operations and maintenance decreased primarily due to $1.3 million of integration activities and transition expenses charged to the Corporate segment and $2.6 million of lower employee costs driven by a change in operating expense and capital allocations impacting the electric utilities as a result of integrating the acquired SourceGas utilities, partially offset by outage related maintenance expenses in the current year.

Depreciation and amortization increased primarily due to a higher asset base.

Interest expense, net decreased primarily due to higher AFUDC interest income driven by construction in process in the current period compared to the same period in the prior year.

Other income (expense), net increased primarily due to higher AFUDC equity in the current period compared to the same period in the prior year.

Income tax benefit (expense): The effective tax rate was comparable to the same period in the prior year.

Gas Utilities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Variance	2016	2015	Variance
	(in thousands)					
Revenue:						
Natural gas — regulated	$138,023	$80,316	$57,707	$392,477	$325,945	$66,532
Other — non-regulated services	13,938	7,347	6,591	29,957	15,850	14,107
Total revenue	151,961	87,663	64,298	422,434	341,795	80,639
Cost of sales						
Natural gas — regulated	43,159	33,499	9,660	172,923	195,882	(22,959)
Other — non-regulated services	5,146	3,571	1,575	13,346	7,484	5,862
Total cost of sales	48,305	37,070	11,235	186,269	203,366	(17,097)
Gross margin	103,656	50,593	53,063	236,165	138,429	97,736
Operations and maintenance	62,237	33,966	28,271	114,924	72,145	42,779
Depreciation and amortization	19,931	7,943	11,988	35,903	15,765	20,138
Total operating expenses	82,168	41,909	40,259	150,827	87,910	62,917
Operating income (loss)	21,488	8,684	12,804	85,338	50,519	34,819
Interest expense, net	(19,074)	(4,178)	(14,896)	(32,591)	(8,566)	(24,025)
Other income (expense), net	(261)	23	(284)	390	7	383
Income tax benefit (expense)	(1,184)	(1,294)	110	(20,193)	(15,137)	(5,056)
Net income (loss)	969	3,235	(2,266)	32,944	26,823	6,121
Net (income) loss attributable to noncontrolling interest	18	—	18	(30)	—	(30)
Net income (loss) available for common stock	$987	$3,235	$(2,248)	$32,914	$26,823	$6,091

The following table summarizes our system infrastructure updated to include our acquired SourceGas utilities:

System Infrastructure (in line miles) as of June 30, 2016	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Arkansas	886	4,572	906
Colorado	678	6,481	2,323
Nebraska	1,249	8,330	3,319
Iowa	180	2,740	2,639
Kansas	293	2,826	1,328
Wyoming	1,299	3,375	1,208
Total	4,585	28,324	11,723

Revenue (in thousands)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Residential:				
Arkansas	$9,799	$—	$25,577	$—
Colorado	21,361	9,861	53,141	35,597
Nebraska	20,314	15,628	66,848	72,072
Iowa	12,787	12,978	47,634	59,344
Kansas	9,320	8,814	31,668	38,142
Wyoming	11,126	4,541	24,673	13,253
Total Residential	$84,707	$51,822	$249,541	$218,408
Commercial:				
Arkansas	$4,764	$—	$12,436	$—
Colorado	7,956	1,827	18,163	6,924
Nebraska	3,256	3,895	16,339	22,107
Iowa	4,336	4,894	19,473	26,523
Kansas	2,090	2,992	10,260	14,058
Wyoming	3,476	2,413	9,179	7,367
Total Commercial	$25,878	$16,021	$85,850	$76,979
Industrial:				
Arkansas	$747	$—	$1,584	$—
Colorado	260	218	505	247
Nebraska	69	582	187	899
Iowa	250	443	825	1,698
Kansas	1,959	2,756	2,589	4,497
Wyoming	703	534	1,657	2,434
Total Industrial	$3,988	$4,533	$7,347	$9,775
Transportation:				
Arkansas	$2,123	$—	$3,758	$—
Colorado	916	238	1,852	603
Nebraska	8,162	2,431	15,951	7,827
Iowa	1,080	1,037	2,555	2,699
Kansas	1,355	1,430	3,398	3,931
Wyoming	2,266	675	4,881	1,506
Total Transportation	$15,902	$5,811	$32,395	$16,566

Revenue (in thousands) (continued)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Transmission:				
Arkansas	$—	$—	$—	$—
Colorado	3,074	—	7,617	—
Nebraska	179	—	206	—
Iowa	—	—	—	—
Kansas	—	—	—	—
Wyoming	637	—	974	—
Total Transmission	$3,890	$—	$8,797	$—
Pipeline Revenue	$859	$—	$1,506	$—
Other Sales Revenue:				
Arkansas	$582	$—	$1,407	$—
Colorado	74	373	181	416
Nebraska	873	613	1,674	1,270
Iowa	213	208	313	347
Kansas	643	861	2,633	2,026
Wyoming	414	74	833	158
Total Other Sales Revenue	$2,799	$2,129	$7,041	$4,217
Total Regulated Revenue	$138,023	$80,316	$392,477	$325,945
Non-regulated Services	13,938	7,347	29,957	15,850
Total Revenue	$151,961	$87,663	$422,434	$341,795

Gross Margin (in thousands)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Residential:				
Arkansas	$7,752	$—	$17,381	$—
Colorado	9,819	3,689	21,296	10,026
Nebraska	15,923	9,716	38,395	28,706
Iowa	8,989	8,814	22,596	22,712
Kansas	6,444	6,204	16,529	17,682
Wyoming	8,475	2,745	17,206	6,523
Total Residential	$57,402	$31,168	$133,403	$85,649
Commercial:				
Arkansas	$2,975	$—	$6,951	$—
Colorado	3,089	574	6,254	1,614
Nebraska	1,756	1,714	6,213	6,383
Iowa	2,168	2,117	6,457	6,753
Kansas	1,100	1,493	4,011	4,880

Wyoming	1,714	891	4,378	2,319
Total Commercial	$12,802	$6,789	$34,264	$21,949

Gross Margin (in thousands) (continued)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Industrial:				
Arkansas	$344	$—	$662	$—
Colorado	130	69	241	90
Nebraska	50	158	95	239
Iowa	44	50	87	131
Kansas	539	557	768	950
Wyoming	147	83	350	345
Total Industrial	$1,254	$917	$2,203	$1,755
Transportation:				
Arkansas	$2,123	$—	$3,758	$—
Colorado	916	238	1,852	603
Nebraska	8,162	2,431	15,951	7,827
Iowa	1,080	1,037	2,555	2,699
Kansas	1,355	1,430	3,398	3,931
Wyoming	2,266	675	4,881	1,506
Total Transportation	$15,902	$5,811	$32,395	$16,566
Transmission:				
Arkansas	$—	$—	$—	$—
Colorado	3,064	—	7,608	—
Nebraska	179	—	206	—
Iowa	—	—	—	—
Kansas	—	—	—	—
Wyoming	673	—	950	—
Total Transmission	$3,916	$—	$8,764	$—
Pipeline	$789	$—	$1,495	$—
Other Sales Margins:				
Arkansas	$582	$—	$1,407	$—
Colorado	74	374	181	417
Nebraska	873	613	1,674	1,270
Iowa	213	208	313	347
Kansas	643	863	2,622	1,952
Wyoming	414	74	833	158
Total Other Sales Margins	$2,799	$2,132	$7,030	$4,144
Total Regulated Gross Margin	$94,864	$46,817	$219,554	$130,063
Non-regulated Services	8,792	3,776	16,611	8,366
Total Gross Margin	$103,656	$50,593	$236,165	$138,429

Distribution Quantities Sold and Transportation (in Dth)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Residential:				
Arkansas	852,523	—	2,745,603	—
Colorado	2,528,067	1,049,937	6,945,901	3,996,742
Nebraska	1,984,185	1,147,696	8,425,278	7,106,652
Iowa	1,227,179	1,045,198	6,265,928	6,561,235
Kansas	736,678	596,296	3,654,752	3,950,110
Wyoming	1,685,312	469,750	4,122,162	1,410,157
Total Residential	9,013,944	4,308,877	32,159,624	23,024,896
Commercial:				
Arkansas	683,030	—	1,823,369	—
Colorado	993,923	218,528	2,438,460	835,726
Nebraska	425,341	442,952	2,416,070	2,623,646
Iowa	728,477	685,373	3,302,428	3,565,464
Kansas	275,512	334,343	1,550,400	1,769,847
Wyoming	660,375	398,228	1,812,102	1,068,817
Total Commercial	3,766,658	2,079,424	13,342,829	9,863,500
Industrial:				
Arkansas	181,305	—	342,996	—
Colorado	90,351	43,535	128,328	45,937
Nebraska	14,375	107,625	32,712	153,325
Iowa	64,611	87,777	191,810	278,782
Kansas [(a)]	765,078	701,122	929,423	1,025,901
Wyoming	215,507	118,781	488,032	420,058
Total Industrial	1,331,227	1,058,840	2,113,301	1,924,003
Wholesale and Other:				
Arkansas	16,405	—	29,640	—
Colorado	—	—	—	—
Nebraska	—	—	—	—
Iowa	—	—	—	—
Kansas [(a)]	—	927	—	14,902
Wyoming	—	—	—	—
Total Wholesale and Other	16,405	927	29,640	14,902
Total Distribution Quantities Sold	14,128,234	7,448,068	47,645,394	34,827,301
Transportation:				
Arkansas	2,137,720	—	3,549,312	—
Colorado	800,220	230,437	1,598,813	610,486
Nebraska	10,616,454	6,509,208	21,830,950	15,558,983
Iowa	4,635,739	4,599,639	10,466,083	10,687,688
Kansas	3,234,621	3,564,124	7,048,006	7,861,476
Wyoming	6,409,106	2,693,738	10,945,275	5,886,418
Total Transportation	27,833,860	17,597,146	55,438,439	40,605,051

Total Distribution Quantities Sold and Transportation	41,962,094	25,045,214	103,083,833	75,432,352

(a) Change from prior year due to a change in Wholesale customer classification to Industrial classification.

Our Gas Utilities are highly seasonal, and sales volumes vary considerably with weather and seasonal heating and industrial loads. Over 70% of our Gas Utilities' revenue and margins are expected in the first and fourth quarters of each year. Therefore, revenue for, and certain expenses of, these operations fluctuate significantly among quarters. Depending upon the state in which our Gas Utilities operate, the winter heating season begins around November 1 and ends around March 31.

	Three Months Ended June 30,				
	2016			2015	
Heating Degree Days: [c]	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Arkansas [a]	232	62%	N/A	—	—%
Colorado	889	3%	—%	887	(4)%
Nebraska	440	(30)%	(7)%	474	(18)%
Iowa	633	(8)%	(2)%	649	(5)%
Kansas [a]	407	(9)%	1%	403	(10)%
Wyoming	1,171	(12)%	—%	1,173	(2)
Combined [b]	620	(10)%	(5)%	655	(9)%

	Six Months Ended June 30,				
	2016			2015	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Arkansas [a]	1,189	(7)%	N/A	—	— %
Colorado	3,517	(7)%	3%	3,422	(8)%
Nebraska	3,121	(16)%	(11)%	3,488	(3)%
Iowa	3,715	(9)%	(17)%	4,483	10 %
Kansas [a]	2,570	(13)%	(6)%	2,725	(6)%
Wyoming	4,020	(9)%	5%	3,824	(9)
Combined [b]	3,069	(11)%	(20)%	3,832	— %

(a) Kansas Gas has an approved weather normalization mechanism within its rate structure, which minimizes weather impact on gross margins. Arkansas has a weather normalization mechanism in effect during the months of November through April and is included for those customers with residential and business rate schedules. The weather normalization mechanism in Arkansas differs from that in Kansas in that it only uses one location to calculate the weather, compared to Kansas, which uses multiple locations. The weather normalization mechanism in Arkansas minimizes weather impact, but does not eliminate the impact.

(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas due to its weather normalization mechanism.

(c) The combined 2015 variance from 30-Year Average reflects the inclusion of Cheyenne Light's natural gas utility operations.

Results of Operations for the Gas Utilities for the Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015: Net income available for common stock for the Gas Utilities was $1.0 million for the three months ended June 30, 2016, compared to Net income available for common stock of $3.2 million for the three months ended June 30, 2015, as a result of:

Gross margin increased primarily due to margins of approximately $52 million contributed by the SourceGas utilities acquired on Feb. 12, 2016. An additional margin increase of $1.1 million was attributable to year-over-year customer growth primarily from our 2015 Wyoming gas system acquisitions.

Operations and maintenance increased primarily due to additional operating costs of approximately $29 million for the acquired SourceGas utilities. Partially offsetting this increase were lower employee costs primarily due to $1.2 million of integration and transition expenses charged to our Corporate segment, and lower property taxes at our Kansas utility.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas utilities of approximately $12 million, and due to a higher asset base at our other utilities over the same period in the prior year.

Interest expense, net increased primarily due to additional interest expense of approximately $15 million from the acquired SourceGas utilities.

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

Income tax benefit (expense): The effective tax rate, including the impact of the acquired SourceGas utilities, is higher due primarily to a change in projections, the impact of which was more pronounced in the current period as a result of lower pre-tax income.

Results of Operations for the Gas Utilities for the Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015: Net income available for common stock for the Gas Utilities was $32.9 million for the six months ended June 30, 2016, compared to Net income available for common stock of $26.8 million for the six months ended June 30, 2015, as a result of:

Gross margin increased primarily due to margins of approximately $98 million contributed by the SourceGas utilities acquired on February 12, 2016. An additional margin increase of $2.9 million was attributable to year-over-year customer growth primarily from our 2015 Wyoming gas system acquisitions. Partially offsetting these increases was a $2.7 million decrease due to weather. Heating degree days were 20% lower for the six months ended June 30, 2016, compared to the same period in the prior year and 11% lower than normal in the current year, compared to being equal to normal in the prior year.

Operations and maintenance increased primarily due to additional operating costs of approximately $46 million for the acquired SourceGas utilities. Partially offsetting this increase were lower employee costs primarily due to $2.9 million of integration and transition expenses charged to our Corporate segment, and lower property taxes at our Kansas utility.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas utilities of approximately $19 million, and due to a higher asset base at our other utilities over the same period in the prior year.

Interest expense, net increased primarily due to additional interest expense of approximately $24 million from the acquired SourceGas utilities.

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

Income tax benefit (expense): The effective tax rate, including the impact of the acquired SourceGas utilities, is comparable to the same period in the prior year.

Regulatory Matters

For more information on enacted regulatory provisions with respect to the states in which our Utilities operate, see Part I, Items 1 and 2 of our 2015 Annual Report on Form 10-K filed with the SEC.

Colorado Electric Rate Case filing

On May 3, 2016, Colorado Electric filed a rate request with the CPUC to increase annual revenues by $8.9 million to recover investments in the $65 million, 40 MW natural gas-fired combustion turbine, currently under construction. The filing seeks a return on equity of 9.83% and a capital structure of 50.92% equity and 49.08% debt.

Black Hills Gas Holdings Regulatory Matters

The following table illustrates information about certain enacted regulatory provisions with respect to the states in which our acquired SourceGas utilities operate:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Tariff and Rate Matters
Arkansas Gas	AR	9.4%	6.47%(a)	52%/48%	$299.4(b)	2/2015	Gas Cost Adjustment, Main Replacement Program, At-Risk Meter Replacement Program, legislative/regulatory mandate and relocations rider, Energy Efficiency, Weather Normalization Adjustment, Billing Determinant Adjustment
Colorado Gas	CO	10%	8.02%	49.52%/50.48%	$127.1	12/2010	Gas Cost Adjustment, DSM
Nebraska Gas	NE	9.60%	7.67%	48.84%/51.16%	$87.6/$69.8(c)	6/2012	Choice Gas Program, System Safety and Integrity Rider, Bad Debt expense recovered through Choice supplier fee
Wyoming Gas	WY	9.92%	7.98%	49.66%/50.34%	$100.5	1/2011	Choice Gas Program, Purchased Gas Cost Adjustment, Usage Per Customer Adjustment
RMNG	CO	10.6%	7.93%	49.23%/50.77%	$90.5	3/2013	System Safety Integrity Rider, liquids/off-system/market center services Revenue Sharing

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(a) Arkansas return on rate base adjusted to remove current liabilities from rate case capital structure for comparison with other subsidiaries.
(b) Arkansas rate base adjusted to include current liabilities for comparison with other subsidiaries.
(c) Total Nebraska rate base of $87.6 million includes amounts allocated to serve non-jurisdictional and agricultural customers. Jurisdictional Nebraska rate base of $69.8 million excludes those amounts allocated to serve

non-jurisdictional and agricultural customers and is used for calculation of jurisdictional base rates.

Some of the mechanisms in place at the Black Hills Gas Holdings utilities include the following:

- In Arkansas, we have tariff adjustment mechanisms for weather normalization and revenue erosion from a decline in billing determinants. We also have tariffs that allow more timely recovery of main replacements, at-risk meter replacements and expenditures due to legislative/regulatory mandates and relocations outside of a rate case.
- In Nebraska and for RMNG, we have a system safety and integrity rider that recovers forecast safety and integrity capital expenditure-related costs and operating and maintenance expenses.
- In Nebraska, we are allowed to recover uncollectible accounts expenses through a choice supplier fee.
- In Wyoming, we have a cost adjustment to recover lost revenue due to declining usage per customer and a rider to recover the cost of replacing above ground pipe.

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The following summarizes Black Hills Gas Holdings' recent state and federal rate case and initial surcharge orders (in millions):

	Type of Service	Date Requested	Effective Date	Revenue Amount Requested	Revenue Amount Approved
Arkansas Gas [a]	Gas	4/2015	2/2016	$ 12.6	$ 8.0
RMNG[b]	Gas - transmission and storage	11/2015	1/2016	$ 1.5	$ 1.5
Nebraska Gas [c]	Gas	10/2015	2/2016	$ 3.8	$ 3.8
Wyoming Gas [d]	Gas	2/2010	1/2011	$ 7.5	$ 4.3
Colorado Gas [e]	Gas	6/2010	12/2010	$ 6.0	$ 2.8

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(a) In February 2016, Arkansas Gas implemented new base rates resulting in a revenue increase of $8.0 million. The APSC modified a stipulation reached between the APSC Staff and all intervenors except the Attorney General and Arkansas Gas in its order issued on January 28, 2016. The modified stipulation revised the capital structure to 52% debt and 48% equity and also limited recovery of portions of cost related to incentive compensation.

(b) On November 1, 2015, RMNG filed with the CPUC requesting recovery of $1.5 million related to system safety and integrity "SSIR" expenditures expected to be incurred in 2016. The SSIR rate was adjusted downward to reflect a true up of $0.7 million from the expenditure projection for 2014. The SSIR tariff was allowed to go into effect by operation of law on January 1, 2016.

(c) On November 1, 2015, Nebraska Gas filed with the NPSC requesting recovery of $3.8 million related to system safety and integrity expenditures expected to be incurred in 2016. The SSIR tariff was approved by the NPSC on January 12, 2016 to go into effect on February 1, 2016.

(d) On January 1, 2011, Wyoming Gas implemented new base rates in accordance with the order by the WPSC issued on December 23, 2010. The approved rates were based upon an authorized return on equity of 9.92% and a capital structure of 49.66% debt and 50.34% equity. The rate increase represented a $4.3 million increase over existing rates.

(e) On December 1, 2010, the CPUC issued an order approving a stipulation to increase Colorado Gas base rates by $2.8 million. The stipulated rate increase was based upon an authorized return on equity of 10.00% and a capital structure of 49.23% debt and 50.77% equity. Increased rates became effective on December 3, 2010.

Cost of Service Gas Program filings

On September 30, 2015, BHC's utility subsidiaries submitted applications with respective state utility regulators seeking approval for a Cost of Service Gas Program in Iowa, Kansas, Nebraska, South Dakota and Wyoming. An application was submitted in Colorado on November 2, 2015. The Cost of Service Gas Program is 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.

The Company's initial cost of service applications were developed during a two-year period with input from state regulatory commissioners, staff and consumer advocates to structure the program using a two-phase approach. The first phase would establish the criteria for how the program would work and the second phase would seek approval for a specific gas reserves property.

Hearings for approval of the Cost of Service Gas Program were conducted in Nebraska and Iowa in April and May, respectively. On July 19, 2016, the NPUC issued an order denying our application. In April, the CPUC dismissed without prejudice the Company's application. Orders from these two states indicated that the initial phase filings contained insufficient information and data to support customer benefits. Hearings were scheduled for Wyoming in August 2016, and for Kansas and South Dakota in September 2016. On July 26, 2016 the Company announced it requested a withdrawal of proceedings for its Cost of Service Gas application in Wyoming and has subsequently filed to withdraw its applications in Iowa, Kansas and South Dakota. Based on pre-hearing discovery and the two commission orders, the Company is considering filing new applications for approval of specific gas reserve properties.

Power Generation

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Variance	2016	2015	Variance
	(in thousands)					
Revenue [a]	$21,714	$22,309	$(595)	$45,022	$44,983	$39
Operations and maintenance	8,648	8,483	165	16,690	16,311	379
Depreciation and amortization [a]	1,053	1,115	(62)	2,084	2,249	(165)
Total operating expense	9,701	9,598	103	18,774	18,560	214
Operating income	12,013	12,711	(698)	26,248	26,423	(175)
Interest expense, net	(120)	(788)	668	(934)	(1,674)	740
Other (expense) income, net	(19)	7	(26)	4	5	(1)
Income tax (expense) benefit	(3,559)	(4,381)	822	(8,421)	(9,060)	639
Net income (loss)	$8,315	$7,549	$766	$16,897	$15,694	$1,203
Net income attributable to noncontrolling interest	(2,632)	—	(2,632)	(2,632)	—	(2,632)
Net income (loss) available for common stock	$5,683	$7,549	$(1,866)	$14,265	$15,694	$(1,429)

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(a) The generating facility located in Pueblo, Colorado is accounted for as a capital lease under GAAP; as such, revenue and depreciation expense are impacted by the accounting for this lease. Under the lease, the original cost of the facility is recorded at Colorado Electric and is being depreciated by Colorado Electric for segment reporting purposes.

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million. Black Hills Colorado IPP 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. Net income available for common stock for the three and six months ended June 30, 2016, was reduced by $2.6 million attributable to this noncontrolling interest.

The following table summarizes MWh for our Power Generation segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Quantities Sold, Generated and Purchased (MWh) [(a)]				
Sold				
Black Hills Colorado IPP	310,442	267,360	644,320	551,851
Black Hills Wyoming [(b)]	141,976	165,557	309,007	325,115
Total Sold	452,418	432,917	953,327	876,966
Generated				
Black Hills Colorado IPP	310,442	267,360	644,320	551,851
Black Hills Wyoming	119,985	139,267	258,904	277,240
Total Generated	430,427	406,627	903,224	829,091
Purchased				
Black Hills Wyoming [(b)]	16,936	13,099	45,239	37,491
Total Purchased	16,936	13,099	45,239	37,491

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(a) Company uses and losses are not included in the quantities sold, generated, and purchased.

(b) Under the 20-year economy energy PPA with the City of Gillette, effective September 2014, Black Hills Wyoming purchases energy on behalf of the City of Gillette and sells that energy to the City of Gillette.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Contracted power plant fleet availability:				
Coal-fired plant [(a)]	85.9%	97.4%	91.8%	97.8%
Natural gas-fired plants	99.2%	99.0%	99.3%	99.0%
Total availability	95.8%	98.6%	97.4%	98.7%

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(a) Decrease due to a planned outage on Wygen I during the three months ended June 30, 2016.

Results of Operations for Power Generation for the Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015: Net income available for common stock for the Power Generation segment was $5.7 million for the three months ended June 30, 2016, compared to Net income available for common stock of $7.5 million for the same period in 2015 as a result of:

Revenue decreased primarily due to a decrease in contracted revenue driven by the Wygen I outage in the current year, partially offset by an increase in PPA pricing.

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

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

Interest expense, net decreased due to higher interest income driven by the proceeds from the noncontrolling interest sale in April 2016.

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

Income tax (expense) benefit: The effective tax rate is lower than the same period in the prior year due to the effect of the current period noncontrolling interest. 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 percent of its membership interest in April 2016.

Results of Operations for Power Generation for the Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015: Net income available for common stock for the Power Generation segment was $14 million for the six months ended June 30, 2016, compared to Net income available for common stock of $16 million for the same period in 2015 as a result of:

Revenue was comparable to the same prior year reflecting an increase in PPA pricing and an increase in MWh sold, offset by a decrease in contracted revenue driven by the Wygen I plant outage.

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

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

Interest expense, net decreased due to higher interest income driven by the proceeds from the noncontrolling interest sale in April 2016.

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

Income tax (expense) benefit: The effective tax rate is lower than the same period in the prior year due to the effect of the current period noncontrolling interest. 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 percent of its membership interest in April 2016.

Mining

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Variance	2016	2015	Variance
	(in thousands)					
Revenue	$11,047	$16,725	$(5,678)	$27,329	$32,659	$(5,330)
Operations and maintenance	8,287	10,661	(2,374)	18,721	20,565	(1,844)
Depreciation, depletion and amortization	2,448	2,461	(13)	4,927	4,964	(37)
Total operating expenses	10,735	13,122	(2,387)	23,648	25,529	(1,881)
Operating income (loss)	312	3,603	(3,291)	3,681	7,130	(3,449)
Interest (expense) income, net	(91)	(102)	11	(183)	(191)	8
Other income, net	532	548	(16)	1,066	1,133	(67)
Income tax benefit (expense)	(29)	(1,000)	971	(902)	(2,013)	1,111
Net income (loss)	$724	$3,049	$(2,325)	$3,662	$6,059	$(2,397)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Tons of coal sold	614	1,076	1,616	2,095
Cubic yards of overburden moved [(a)]	1,686	1,392	3,451	2,805
Revenue per ton	$17.99	$15.54	$16.91	$15.59

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(a) Increase is driven by mining in areas with more overburden than in the prior year.

Results of Operations for Mining for the Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015: Net income available for common stock for the Mining segment was $0.7 million for the three months ended June 30, 2016, compared to Net income available for common stock of $3.0 million for the same period in 2015 as a result of:

Revenue decreased primarily due to a 43% decrease in tons sold driven by a planned five-week outage, which was extended by an additional six weeks at the Wyodak plant due to an unplanned major turbine rotor repair, and additional outages at Wygen I and Wygen III, partially offset by a 16% increase in price per ton sold. The increase in price per ton sold was driven by contract price adjustments based on actual mining costs. Due to the current period outages, approximately 65% of the mine's production was sold under contracts that include price adjustments based on actual mining costs, including income taxes, compared to approximately 50% in the same period of the prior year.

Operations and maintenance decreased primarily due to lower major maintenance expenses related to the reduced coal production during the quarter, lower royalties and production taxes on reduced revenue, and lower employee costs.

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

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

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

Income tax benefit (expense): The effective tax rate was lower than the same period in the prior year due to the impact of the tax benefit of percentage depletion.

Results of Operations for Mining for the Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015: Net income available for common stock for the Mining segment was $3.7 million for the six months ended June 30, 2016, compared to Net income available for common stock of $6.1 million for the same period in 2015 as a result of:

Revenue decreased primarily due to a 23% decrease in tons sold due to a planned five-week outage, which was extended by an additional six weeks at the Wyodak plant due to an unplanned major repair of a turbine rotor, as well as lower sales to other generating plants, partially offset by an 8% increase in price per ton sold. The increase in price per ton sold was driven by contract price adjustments based on actual mining costs. Approximately 50% of the mine's production is sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operations and maintenance decreased primarily due lower royalties and production taxes on reduced revenues and lower employee costs, partially offset by mining in areas with higher overburden.

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

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

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

Income tax benefit (expense): The effective tax rate was lower than the same period in the prior year due to the impact of the tax benefit of percentage depletion.

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Oil and Gas

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Variance	2016	2015	Variance
	(in thousands)					
Revenue	$7,646	$12,319	$(4,673)	$16,021	$23,586	$(7,565)
Operations and maintenance	7,912	10,988	(3,076)	16,947	21,905	(4,958)
Depreciation, depletion and amortization	3,819	8,790	(4,971)	7,932	16,301	(8,369)
Impairment of long-lived assets	25,497	94,484	(68,987)	39,993	116,520	(76,527)
Total operating expenses	37,228	114,262	(77,034)	64,872	154,726	(89,854)
Operating income (loss)	(29,582)	(101,943)	72,361	(48,851)	(131,140)	82,289
Interest income (expense), net	(1,159)	(478)	(681)	(2,233)	(862)	(1,371)
Other income (expense), net	30	7	23	69	(216)	285
Impairment of equity investments	—	(5,170)	5,170	—	(5,170)	5,170
Income tax benefit (expense)	11,287	36,389	(25,102)	24,567	47,078	(22,511)
Net income (loss)	$(19,424)	$(71,195)	$51,771	$(26,448)	$(90,310)	$63,862

The following tables provide certain operating statistics for our Oil and Gas segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Production:				
Bbls of oil sold	76,152	98,905	174,219	179,635
Mcf of natural gas sold	2,435,454	2,701,721	4,722,060	4,955,763
Bbls of NGL sold	40,892	33,271	77,895	62,041
Mcf equivalent sales	3,137,718	3,494,780	6,234,744	6,405,823

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Average price received: (a) (b)				
Oil/Bbl	$60.16	$65.09	$53.22	$65.88
Gas/Mcf	$0.93	$1.79	$1.11	$1.98
NGL/Bbl	$11.23	$19.82	$10.82	$17.00
Depletion expense/Mcfe	$0.83	$2.22	$0.88	$2.21

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(a) Net of hedge settlement gains and losses.

(b) Pre-tax impairments of long-lived Oil and Gas properties of $25 million and $40 million, and $94 million and $117 million were recorded for the three and six months ended June 30, 2016 and June 30, 2015, respectively.

The following is a summary of certain average operating expenses per Mcfe:

	Three Months Ended June 30, 2016				Three Months Ended June 30, 2015			
Producing Basin	LOE	Gathering, Compression, Processing and Transportation (a)	Production Taxes	Total	LOE	Gathering, Compression, Processing and Transportation (a)	Production Taxes	Total
San Juan	$1.51	$ 1.05	$ 0.23	$2.79	$1.25	$ 1.38	$ 0.57	$3.20
Piceance	0.34	1.80	0.09	2.23	0.62	1.76	0.17	2.55
Powder River	2.95	—	0.57	3.52	2.09	—	0.83	2.92
Williston	2.88	—	1.00	3.88	1.13	—	0.36	1.49
All other properties	0.19	—	0.12	0.31	2.10	—	1.08	3.18
Total weighted average	$1.07	$ 1.20	$ 0.23	$2.50	$1.12	$ 1.18	$ 0.44	$2.74

	Six Months Ended June 30, 2016				Six Months Ended June 30, 2015			
Producing Basin	LOE	Gathering, Compression, Processing and Transportation (a)	Production Taxes	Total	LOE	Gathering, Compression, Processing and Transportation (a)	Production Taxes	Total
San Juan	$1.63	$ 1.07	$ 0.27	$2.97	$1.42	$ 1.34	$ 0.47	$3.23
Piceance	0.34	1.87	0.11	2.32	0.51	2.05	0.18	2.74
Powder River	2.78	—	0.56	3.34	2.47	—	0.70	3.17
Williston	1.53	—	0.52	2.05	0.74	—	0.24	0.98
All other properties	0.40	—	0.07	0.47	1.64	—	0.68	2.32
Total weighted average	$1.08	$ 1.17	$ 0.24	$2.49	$1.15	$ 1.25	$ 0.38	$2.78

(a) These costs include both third-party costs and operations costs.

In the Piceance and San Juan Basins, our natural gas is transported through our own and third-party gathering systems and pipelines, for which we incur processing, gathering, compression and transportation fees. The sales price for natural gas, condensate and NGLs is reduced for these third-party costs, while the cost of operating our own gathering systems is included in operations and maintenance. The gathering, compression, processing and transportation costs shown in the tables above include amounts paid to third parties, as well as costs incurred in operations associated with our own gas gathering, compression, processing and transportation.

We have a ten-year gas gathering and processing contract for natural gas production in our Piceance Basin which became effective in March of 2014. This take-or-pay contract requires us to pay a fee on a minimum of 20,000 Mcf per day, regardless of the volume delivered. We did not meet the minimum requirements of this contract until mid-February 2015. Our gathering, compression and processing costs on a per Mcfe basis, as shown in the table above, will be higher in periods when we are not meeting the minimum contract requirements.

Results of Operations for Oil and Gas for the Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015: Net loss available for common stock for the Oil and Gas segment was $19.4 million for the three months ended June 30, 2016, compared to Net loss available for common stock of $71 million for the same period in 2015 as a result of:

Revenue decreased primarily due to lower commodity prices for both crude oil and natural gas, resulting in an 8% decrease in the average hedged price received for crude oil sold, and a 48% decrease in the average hedged price received for natural gas sold. Production decreased by 10%, as a result of limiting current year production to meet minimum daily quantity contractual gas processing commitments in the Piceance.

Operations and maintenance decreased primarily due to lower employee costs as a result of the reduction in staffing in the prior year, and lower production taxes and ad valorem taxes on lower revenue.

Depreciation, depletion and amortization decreased primarily due to the reduction in our full cost pool resulting from the impact of the ceiling test impairments incurred in the current and prior years.

Impairment of long-lived assets represents non-cash write-downs in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices and advancing our strategy to transition Oil and Gas to support Cost of Service Gas programs. The current write-down of $25 million included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $11 million. The ceiling test write-down in the second quarter of 2016 used a trailing 12 month average NYMEX natural gas price of $2.24 per Mcf, adjusted to $1.01 per Mcf at the wellhead, and $43.12 per barrel for crude oil, adjusted to $37.19 per barrel at the wellhead, compared to the $94 million ceiling test write-down in the same period of the prior year which used a trailing 12 month average NYMEX natural gas price of $3.39 per Mcf, adjusted to $2.14 per Mcf at the wellhead, and $71.68 per barrel for crude oil, adjusted to $63.76 per barrel at the wellhead.

Interest income (expense), net increased primarily due to higher interest expense driven by an increase in intercompany notes payable.

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

Impairment of equity investments represents a prior year $5.2 million non-cash write-down in equity investments related to interests in a pipeline and gathering system. The impairment resulted from continued declining performance, market conditions and a change in view of the economics of the facilities that we considered to be other than temporary.

Income tax (expense) benefit: Each period represents a tax benefit. The effective tax rate for the same period of the prior year was lower as a result of an unfavorable inter-period tax adjustment.

Results of Operations for Oil and Gas for the Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015: Net loss available for common stock for the Oil and Gas segment was $26.4 million for the six months ended June 30, 2016, compared to Net loss available for common stock of $90 million for the same period in 2015 as a result of:

Revenue decreased primarily due to lower commodity prices for both crude oil and natural gas, resulting in a 19% decrease in the average hedged price received for crude oil sold, and a 44% decrease in the average hedged price received for natural gas sold. Production decreased 3% as a result of limiting current year production to meet minimum daily quantity contractual gas processing commitments in the Piceance.

Operations and maintenance decreased primarily due to lower employee costs as a result of the reduction in staffing in the prior year, and lower production taxes and ad valorem taxes on lower revenue.

Depreciation, depletion and amortization decreased primarily due to the reduction in our full cost pool resulting from the impact of the ceiling test impairments incurred in the current and prior years.

Impairment of long-lived assets represents non-cash write-downs in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices and advancing our strategy to transition Oil and Gas to support Cost of Service Gas programs. The current write-down of $40 million included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $26 million. The ceiling test write-down for the six months ended June 30, 2016 used a trailing 12 month average NYMEX natural gas price of $2.24 per Mcf, adjusted to $1.01 per Mcf at the wellhead, and $43.12 per barrel for crude oil, adjusted to $37.19 per barrel at the wellhead, compared to the $117 million ceiling test write-down in the same period of the prior year which used a trailing 12 month average NYMEX natural gas price of $3.39 per Mcf, adjusted to $2.14 per Mcf at the wellhead, and $71.68 per barrel for crude oil, adjusted to $63.76 per barrel at the wellhead.

Interest income (expense), net increased primarily due to higher interest expense driven by an increase in intercompany notes payable.

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

Impairment of equity investments represents a prior year $5.2 million non-cash write-down in equity investments related to interests in a pipeline and gathering system. The impairment resulted from continued declining performance, market conditions and a change in view of the economics of the facilities that we considered to be other than temporary.

Income tax (expense) benefit: Each period presented reflects a tax benefit. The effective tax rate for 2016 was impacted by a benefit of approximately $5.8 million from additional percentage depletion deductions being claimed with respect to a change in estimate for tax purposes. Such deductions are primarily the result of a change in the application of the maximum daily limitation of 1,000 Bbls of oil equivalent allowed under the Internal Revenue Code.

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015: Net loss available for common stock for Corporate was $6.5 million for the three months ended June 30, 2016, compared to Net loss available for common stock of $2.1 million for the three months ended June 30, 2015. The variance from the prior year was due to higher corporate expenses, primarily driven by costs related to the SourceGas acquisition including approximately $4.1 million of after-tax acquisition and transition costs, and approximately $2.0 million of after-tax internal labor that otherwise would have been charged to other business segments, during the three months ended June 30, 2016.

Results of Operations for Corporate activities for the Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015: Net loss available for common stock for Corporate was $22.2 million for the six months ended June 30, 2016, compared to Net loss available for common stock of $1.4 million for the six months ended June 30, 2015. The variance from the prior year was due to higher corporate expenses, primarily driven by costs related to the SourceGas acquisition including approximately $20 million of after-tax acquisition and transition costs, and approximately $5.7 million of after-tax internal labor that otherwise would have been charged to other business segments, during the six months ended June 30, 2016. These costs were partially offset by a tax benefit of approximately $4.4 million recognized during the six months ended June 30, 2016 as a result of an agreement reached with IRS Appeals relating to the release of the reserve for after-tax interest expense previously accrued with respect to the liability for uncertain tax positions involving a like-kind-exchange transaction from 2008.

Critical Accounting Estimates

Except for the additional disclosure below and in Note 1 of Item 1 on this Form 10-Q, there have been no material changes in our critical accounting estimates from those reported in our 2015 Annual Report on Form 10-K filed with the SEC. For more information on our critical accounting estimates, see Part II, Item 7 of our 2015 Annual Report on Form 10-K.

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. Our significant assumptions and estimates can include, but are not limited to, the cash flows that an acquired entity is expected to generate in the future, the appropriate weighted-average cost of capital, and the savings expected to be derived from the business combination.

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.

Liquidity and Capital Resources

OVERVIEW

Our Company requires significant cash to support and grow our business. Our predominant source of cash is supplied by our operations and supplemented with corporate borrowings. This cash is used for, among other things, working capital, capital expenditures, dividends, pension funding, investments in or acquisitions of assets and businesses, payment of debt obligations, and redemption of outstanding debt and equity securities when required or financially appropriate.

The most significant uses of cash are our capital expenditures, the purchase of natural gas for our Gas Utilities and our Power Generation segment, as well as the payment of dividends to our shareholders. We experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, debt maturities, anticipated dividends, and anticipated capital expenditures discussed in this section. As of June 30, 2016, we have approximately $931 million of long-term debt due over the next twelve months, classified as Current maturities of long-term debt on our Condensed Consolidated Balance Sheets; we intend to refinance all of this debt as outlined below in our Future Financing Plans.

Significant Factors Affecting Liquidity

Although we believe we have sufficient resources to fund our cash requirements, there are many factors with the potential to influence our cash flow position, including seasonality, commodity prices, significant capital projects and acquisitions, requirements imposed by state and federal agencies, and economic market conditions. We have implemented risk mitigation programs, where possible, to stabilize cash flow; however, the potential for unforeseen events affecting cash needs will continue to exist.

Our Utilities maintain wholesale commodity contracts for the purchases and sales of electricity and natural gas which have performance assurance provisions that allow the counterparty to require collateral postings under certain conditions, including when requested on a reasonable basis due to a deterioration in our financial condition or nonperformance. A significant downgrade in our credit ratings, such as a downgrade to a level below investment grade, could result in counterparties requiring collateral postings under such adequate assurance provisions. The amount of credit support that we may be required to provide at any point in the future is dependent on the amount of the initial transaction, changes in the market price, open positions and the amounts owed by or to the counterparty.

We also maintain interest rate swap transactions under which we could be required to post collateral on the value of such swaps in the event of an adverse change in our financial condition, including a credit downgrade to below investment-grade.

At June 30, 2016, we had $2.5 million of collateral posted related to our wholesale commodity contracts transactions, and no collateral posted related to our interest rate swaps. At June 30, 2016, we had sufficient liquidity to cover any additional collateral that could be required to be posted under these contracts.

Cash Flow Activities

The following table summarizes our cash flows for the six months ended June 30 (in thousands):

Cash provided by (used in):	2016	2015	Increase (Decrease)
Operating activities	$222,775	$254,408	$(31,633)
Investing activities	$(1,324,741)	$(207,124)	$(1,117,617)
Financing activities	$762,236	$18,708	$743,528

Year-to-Date 2016 Compared to Year-to-Date 2015

Operating Activities

Net cash provided by operating activities was $223 million for the six months ended June 30, 2016, compared to net cash provided by operating activities of $254 million for the same period in 2015 for a variance of $32 million. The variance was primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $17 million higher for the six months ended June 30, 2016 compared to the same period in the prior year; and

- Net cash inflows from operating assets and liabilities were $20 million for the six months ended June 30, 2016, compared to net cash inflows of $52 million in the same period in the prior year. This $32 million variance was primarily due to:

- Cash inflows increased by approximately $17 million for the six months ended June 30, 2016 compared to the same period in the prior year primarily as a result of changes in accounts receivable and materials and supplies;

- Cash inflows decreased by approximately $30 million primarily as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and commodity price impacts on working capital compared to the same period in the prior year;

- Cash outflows increased by approximately $19 million as a result of changes in accounts payable and accrued liabilities driven primarily by working capital requirements primarily related to acquisition and transition costs and the change in liability with respect to uncertain tax positions in the six months ended June 30, 2016;

- Cash outflows increased by $10 million due to pension contributions; and

- Cash outflows increased by approximately $6 million primarily driven by changes in other non-current assets and other regulatory assets and liabilities.

Investing Activities

Net cash used in investing activities was $1.325 billion for the six months ended June 30, 2016, compared to net cash used in investing activities of $207 million for the same period in 2015. The variance was primarily driven by:

- Cash outflows of $1.124 billion for the acquisition of SourceGas, net of $11 million cash received from a working capital adjustment and $760 million of long term debt assumed (see Note 2 in Item 1 of Part I of this Quarterly Report on Form 10-Q); and

- Capital expenditures of approximately $200 million for the six months ended June 30, 2016 compared to $206 million for the six months ended June 30, 2015. The decrease is primarily due to higher prior year capital expenditures at our Oil and Gas segment due to drilling and completion activity in the Piceance basin, partially offset by current year capital expenditures at our Electric and Gas Utilities.

Financing Activities

Net cash provided by financing activities for the six months ended June 30, 2016 was $762 million, compared to $19 million of net cash provided by financing activities for the same period in 2015. The variance was primarily driven by:

- Proceeds of $216 million from the sale of a 49.9% noncontrolling interest of Black Hills Colorado IPP; (see Note 11 in Item 1 of Part I of this Quarterly Report on Form 10-Q)
- Long-term borrowings increased by $275 million due to the $546 million of net proceeds from our January 13, 2016 public debt offering used to partially finance the SourceGas Acquisition, and proceeds from a $29 million term loan used to fund the early settlement of a gas gathering contract, compared to proceeds of $300 million from long-term borrowings from a term loan in the prior year;
- Payments on long term borrowings decreased by $234 million due to payments made in the current year of $41 million compared to the payment of a $275 million made as part of a term-loan refinancing in the prior year;
- Proceeds of approximately $56 million from issuing common stock under our ATM equity offering program;
- Net short-term borrowings under the revolving credit facility for the six months ended June 30, 2016 were $33 million lower than the prior year primarily due to using proceeds of our ATM equity offering program to fund working capital requirements in the current year; and
- Increased dividend payments of approximately $7.0 million.

Dividends

Dividends paid on our common stock totaled $43 million for the six months ended June 30, 2016, or $0.84 per share. On July 29, 2016, our board of directors declared a quarterly dividend of $0.42 per share payable September 1, 2016, which is equivalent to an annual dividend rate of $1.68 per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our Revolving Credit Facility and our future business prospects.

Debt

Financing Transactions and Short-Term Liquidity

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

Revolving Credit Facility

On June 26, 2015, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through June 26, 2020. 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 the capacity of the facility to $750 million. 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 S&P and 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. A commitment fee is charged on the unused amount of the Revolving Credit Facility and was 0.175% based on our credit rating.

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

Credit Facility	Expiration	Current Capacity	Borrowings at June 30, 2016	Letters of Credit at June 30, 2016	Available Capacity at June 30, 2016
Revolving Credit Facility	June 26, 2020	$ 500	$ 75	$ 25	$ 400

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintaining a certain Recourse Leverage Ratio. Under the Revolving Credit Facility, our recourse leverage ratio is calculated by dividing the sum of our recourse debt, letters of credit, and certain guarantees issued, by total capital, which includes recourse indebtedness plus our net worth excluding minority interests in subsidiaries. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of June 30, 2016.

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

Hedges and Derivatives

Interest Rate Swaps

We have entered into pay fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. We have $75 million notional amount pay fixed interest rate swaps with a maximum remaining term of approximately 0.5 years. These swaps have been designated as cash flow hedges for advances under the Revolving Credit Facility, and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $1.5 million at June 30, 2016.

We have a 10-year, $150 million notional forward starting interest rate swap at an all-in rate of 2.09% and a 10-year, $250 million notional forward starting interest rate swap at an all-in rate of 2.29% to hedge the risks of interest rate movement between their initial hedge dates and the expected pricing date for anticipated future long-term debt refinancings in late 2016 and 2017. These swaps are accounted for as cash flow hedges with any gain or loss initially recorded in AOCI. Both swaps have a mandatory early termination date of April 12, 2017. The mark-to-market value of these swaps was a liability of $27 million at June 30, 2016.

Financing Activities

On June 7, 2016, we entered into a 2.32%, $28.7 million term loan, due June 7, 2021. Proceeds from this term loan were used to finance the regulatory asset related to the early termination of a gas supply contract. Principal and interest are payable quarterly at approximately $1.6 million, the first of which was paid on June 30, 2016.

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for approximately $216 million. FERC approval of the sale was received on March 29, 2016. We used the proceeds from this sale to pay down borrowings on our revolving credit facility.

On March 18, 2016, we implemented an at-the-market 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 June 30, 2016, we sold 809,649 common shares for $49 million, net of $0.5 million in commissions under the ATM equity offering program. Through June 30, 2016, we have sold and issued an aggregate of 930,649 shares of common stock under the ATM equity offering program for $56 million, net of $0.6 million in commissions. Additionally, 46,576 shares for net proceeds of $2.9 million have been sold, but were not settled and are not considered issued and outstanding as of June 30, 2016. Proceeds from the ATM equity offering program were used to fund capital expenditures and for general corporate purposes.

We completed the following equity and debt transactions in placing permanent financing for the SourceGas Acquisition:

- 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 2.5%, 3-year senior notes due 2019. Net proceeds after discounts and fees were approximately $546 million; and

- On November 23, 2015, we completed 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. Each equity unit has a stated amount of $50 and consists of (i) a contract to purchase Company common stock and (ii) a 1/20, or 5%, undivided beneficial ownership interest in $1,000 principal amount of remarketable junior subordinated notes due 2028. Pursuant to the purchase contracts, holders are required to purchase Company common stock no later than November 1, 2018.

Our $1.17 billion bridge commitment signed on July 12, 2015 was reduced to $88 million on January 13, 2016, with respect to reductions from our equity and debt offerings. The remaining commitment terminated on February 12, 2016, as part of the closing of the SourceGas Acquisition.

We assumed the following tranches of debt through the SourceGas Acquisition on February 12, 2016:

- $325 million, 5.9% senior unsecured notes with an original issue date of April 16, 2007, due April 16, 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 expense under this term loan is LIBOR plus a margin of 0.88%.

On January 20, 2016, we executed a 10-year, $150 million notional forward starting pay fixed interest rate swap at an all-in rate of 2.09% to hedge the risks of interest rate movement between the hedge date and the expected pricing date for anticipated future long-term debt refinancings in late 2016 or 2017. The swap is accounted for as a cash flow hedge with any gain or loss recorded in AOCI. The swap has a mandatory early termination date of April 12, 2017.

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 date and the expected pricing date for anticipated future long-term debt refinancings in late 2016 or 2017. The swap is accounted for as a cash flow hedge with any gain or loss recorded in AOCI. The swap has a mandatory early termination date of April 12, 2017.

Future Financing Plans

We anticipate the following financing activities, all or some of which may take place as soon as the third quarter of 2016:

- Continue our At-the-Market equity offering program to issue up to $200 million of common stock;

- Extend and upsize our existing $500 million Revolving Credit Facility to $750 million with a one year extension to 2021;

- Implement a commercial paper program; and

- Refinance approximately $1 billion of near-term debt maturities; any such refinancing may include, among other things, any one or more of the following; a potential issuance of new debt securities in the capital markets, the incurrence of new debt under new or existing credit facilities, amendments to our existing credit facilities, redemption or early prepayment of certain debt; and the settlement or early termination of all or part of our interest rate hedges. Any such new debt issued or incurred will be used to repay existing debt and terminate interest rate hedges of the Company and its subsidiaries.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. As of June 30, 2016, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The only financial covenant under our Revolving Credit Facility and existing term loans is a Recourse Leverage Ratio, which on February 12, 2016, increased upon closing of the SourceGas Acquisition to 0.75 to 1.00 for the next four fiscal quarters; it was previously 0.65 to 1.00. Additionally, covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of June 30, 2016, we were in compliance with these covenants.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2015 Annual Report on Form 10-K filed with the SEC.

Credit Ratings

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

The following table represents the credit ratings and outlook and risk profile of BHC at June 30, 2016:

Rating Agency	Senior Unsecured Rating	Outlook
S&P [(a)]	BBB	Stable
Moody's[(b)]	Baa1	Negative
Fitch [(c)]	BBB+	Negative

(a) On February 12, 2016, S&P affirmed BBB rating and maintained a Stable outlook following the closing of the SourceGas Acquisition, reflecting their expectation that management will continue to focus on the core utility operations while maintaining an excellent business risk profile following the acquisition.

(b) On February 12, 2016, Moody’s affirmed Baa1 rating and maintained a Negative outlook following the closing of the SourceGas Acquisition. Moody’s has maintained a negative outlook as BHC focuses on integrating the newly acquired SourceGas assets over 12 months following the acquisition, closing the 49.9% minority interest sale of Colorado IPP and implementing and utilizing an at-the-market (ATM) equity offering program. In addition, the negative outlook reflects overall weaker consolidated metrics when compared to historical ranges.

(c) On February 12, 2016, Fitch affirmed BBB+ rating and maintained a Negative outlook following the closing of the SourceGas Acquisition, which reflects the initial increased leverage associated with the SourceGas acquisition.

The following table represents the credit ratings of Black Hills Power at June 30, 2016:

Rating Agency	Senior Secured Rating
S&P	A-
Moody’s	A1
Fitch	A

There were no rating changes for Black Hills Power from previously disclosed ratings.

The following table represents the credit ratings of Black Hills Gas at June 30, 2016:

Rating Agency	Senior Unsecured Rating	Outlook
S&P	BBB	Stable
Moody’s	Baa1	Stable
Fitch	BBB+	Positive

Capital Requirements

Acquisition of SourceGas

The acquisition of SourceGas was primarily financed with net proceeds of approximately $536 million from the November 23, 2015 issuance of 6.3 million shares of our common stock and 5.98 million equity units, and $546 million in net proceeds from our debt offerings on January 12, 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.

Capital Expenditures

Actual and forecasted capital requirements are as follows (in thousands):

	Expenditures for the Six Months Ended June 30, 2016 [a]	Total 2016 Planned Expenditures [b][c]	Total 2017 Planned Expenditures	Total 2018 Planned Expenditures
Electric Utilities [c]	$ 135,520	$ 324,000	$ 140,000	$ 148,000
Gas Utilities [d]	73,560	163,000	179,000	156,000
Power Generation	4,260	4,000	5,000	1,000
Mining	1,390	6,000	7,000	7,000
Oil and Gas	1,240	14,000	10,000	10,000
Corporate [e]	2,120	10,000	10,000	9,000
	$ 218,090	$ 521,000	$ 351,000	$ 331,000

(a) Expenditures for the six months ended June 30, 2016 include the impact of accruals for property, plant and equipment.
(b) Includes actual capital expenditures for the six months ended June 30, 2016.
(c) 2016 forecasted capital expenditures for the electric utilities include approximately $97 million for the Peak View Wind Project and the remaining $29 million for Colorado Electric's 40 MW natural gas fired generating unit.
(d) Includes planned expenditures for Black Hills Gas Holdings of $107 million, $105 million and $78 million for 2016, 2017 and 2018, respectively.
(e) Approximately $8 million of capital previously reported as Corporate has been charged to the utilities.

We have removed planned Cost of Service Gas capital expenditures from this forecast due to uncertainties related to the timing of regulatory approvals and other information associated with those approvals, such as the quantity of gas to be provided from a cost of service gas program and whether such gas will be provided from producing reserve purchases or ongoing drilling programs, or both.

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

Contractual Obligations

In addition to our capital expenditure programs, we have contractual obligations and other commitments that will need to be funded in the future. The following information summarizes our cash obligations and commercial commitments at June 30, 2016. The table below has been updated to reflect the additional long-term debt and other commitments and contractual obligations assumed through the acquisition of SourceGas, as well as the agreement in principle reached with IRS Appeals relating to the re-measurement of uncertain tax positions relating to the 2008 IPP Transaction and the Aquila Transaction. Actual future obligations may differ materially from these estimated amounts (in thousands):

	Payments Due by Calendar Period				
Contractual Obligations	Total	2016	2017-2018	2019-2020	Thereafter
Long-term debt[(a)(b)]	$3,170,405	$2,871	$936,486	$560,757	$1,670,291
Unconditional purchase obligations[(c)]	861,381	89,688	282,944	170,366	318,383
Operating lease obligations[(d)]	27,613	2,701	9,183	6,204	9,525
Other long-term obligations[(e)]	46,192	—	—	—	46,192
Employee benefit plans[(f)]	161,054	15,859	48,050	32,132	65,013
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions[(g)]	31,986	26,285	5,701	—	—
Notes payable	75,000	75,000	—	—	—
Total contractual cash obligations[(h)]	$4,373,631	$212,404	$1,282,364	$769,459	$2,109,404

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(a) Long-term debt amounts do not include discounts or premiums on debt.

(b) The following amounts are estimated for interest payments over the next five years based on a mid-year retirement date for long-term debt expiring during the identified period and are not included within the long-term debt balances presented: $80 million in 2016, $111 million in 2017, $98 million in 2018, $95 million in 2019 and $87 million in 2020. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of June 30, 2016.

(c) Unconditional purchase obligations include the energy and capacity costs associated with our PPAs, capacity and certain transmission, gas transportation and storage agreements, and gathering commitments for our Oil and Gas segment. The energy charge under the PPAs are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2016 and price assumptions using existing prices at June 30, 2016. Our transmission obligations are based on filed tariffs as of December 31, 2015. A portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure, are carried out for 60 days. The gathering commitments for our Oil and Gas segment are described in Part I, Delivery Commitments, of our 2015 Annual Report filed on Form 10-K.

(d) Includes operating leases associated with several office buildings, warehouses and call centers, equipment and vehicles.

(e) Includes estimated asset retirement obligations associated with our Electric Utilities, Gas Utilities, Mining and Oil and Gas segments as discussed in Note 8 of the Notes to Consolidated Financial Statements in our 2015 Annual Report on Form 10-K.

(f) Represents both estimated employer contributions to Defined Benefit Pension Plans and payments to employees for the Non-Pension Defined Benefit Postretirement Healthcare Plans and the Supplemental Non-Qualified Defined Benefit Plans through the year 2024.

(g) Less than 1 Year includes a reversal of approximately $26 million associated with the gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction. Such reversal is the result of an agreement that was reached with IRS Appeals during the first quarter of 2016. See Note 20 for additional details.

(h) Amounts in the table exclude: (1) any obligation that may arise from our derivatives, including interest rate swaps and commodity related contracts that have a negative fair value at June 30, 2016. These amounts have been excluded as it is impractical to reasonably estimate the final amount and/or timing of any associated payments; and (2) a portion of our gas purchases are hedged. These hedges are in place to reduce our customers' underlying exposure to commodity price fluctuations. The impact of these hedges is not included in the above table.

Our Utilities have commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. As of June 30, 2016, we are committed to purchase 10.9 Bcf, 13.0 Bcf, 1.2 Bcf and 1.0 Bcf in 2016, 2017, 2018, and 2019, respectively.

Guarantees

Other than those disclosed in Note 18 of the Notes to the Condensed Consolidated Financial Statements on Form 10Q, there have been no significant changes to guarantees from those previously disclosed in Note 20 of the Notes to the Consolidated Financial Statements in our 2015 Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the pronouncements reported in our 2015 Annual Report on Form 10-K filed with the SEC and those discussed in Note 1 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial position, results of operations, or cash flows.

FORWARD-LOOKING INFORMATION

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

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

Any forward-looking statement contained in this document speaks only as of the date on which the statement was made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement was made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements described in our 2015 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2015 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q and other reports that we file with the SEC from time to time.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

Our utility customers are exposed to natural gas price volatility. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. The fair value of our Utilities Group's derivative contracts is summarized below (in thousands) as of:

	June 30, 2016	December 31, 2015	June 30, 2015
Net derivative (liabilities) assets	$(7,894)	$(22,292)	$(16,181)
Cash collateral offset in Derivatives	10,251	22,292	16,181
Cash collateral included in Other current assets	8,067	5,367	5,059
Net asset (liability) position	$10,424	$5,367	$5,059

Oil and Gas Activities

We have entered into agreements to hedge a portion of our estimated 2016 and 2017 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at June 30, 2016, were as follows:

Natural Gas

	March 31	June 30	September 30	December 31	Total Year
2016					
Swaps - MMBtu	—	—	905,000	545,000	1,450,000
Weighted Average Price per MMBtu	$ —	$ —	$ 3.51	$ 3.90	$ 3.66
2017					
Swaps - MMBtu	270,000	270,000	270,000	270,000	1,080,000
Weighted Average Price per MMBtu	$ 2.88	$ 2.88	$ 2.88	$ 2.88	$ 2.88

Crude Oil

	March 31	June 30	September 30	December 31	Total Year
2016					
Swaps - Bbls	—	—	51,000	51,000	102,000
Weighted Average Price per Bbl	$—	$—	$ 72.83	$ 73.14	$ 72.98
2017					
Swaps - Bbls	18,000	18,000	18,000	18,000	72,000
Weighted Average Price per Bbl	$50.07	$50.85	$ 51.55	$ 52.33	$ 51.20
2018					
Swaps - Bbls	9,000	9,000	9,000	9,000	36,000
Weighted Average Price per Bbl	$49.58	$49.85	$ 50.12	$ 50.45	$ 50.00

The fair value of our Oil and Gas segment's derivative contracts is summarized below (in thousands) as of:

	June 30, 2016	December 31, 2015	June 30, 2015
Net derivative (liabilities) assets	$ 2,520	$ 10,088	$ 8,940
Cash collateral offset in Derivatives	(1,150)	(10,088)	(8,940)
Cash Collateral included in Other current assets	—	1,673	2,119
Net asset (liability) position	$ 1,370	$ 1,673	$ 2,119

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations and anticipated long-term refinancings. Further details of the swap agreements are set forth in Note 9 of the Notes to Consolidated Financial Statements in our 2015 Annual Report on Form 10-K and in Note 12 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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:

	June 30, 2016			December 31, 2015		June 30, 2015
	Designated Interest Rate Swaps [(a)]	Designated Interest Rate Swaps [(a)]	Designated Interest Rate Swaps [(b)]	Designated Interest Rate Swaps [(a)]	Designated Interest Rate Swaps [(b)]	Designated Interest Rate Swaps [(b)]
Notional	$150,000	$250,000	$75,000	$250,000	$75,000	$75,000
Weighted average fixed interest rate	2.09 %	2.29 %	4.97 %	2.29 %	4.97 %	4.97 %
Maximum terms in years	0.83	0.83	0.50	1.33	1.00	1.50
Derivative assets, non-current	$—	$—	$—	$3,441	$—	$—
Derivative liabilities, current	$8,553	$18,500	$1,505	$—	$2,835	$3,289
Derivative liabilities, non-current	$—	$—	$—	$—	$156	$1,433
Pre-tax accumulated other comprehensive income (loss)	$(8,553)	$(18,500)	$(1,505)	$3,441	$(2,991)	$(4,722)

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(a) These swaps are designated as cash flow hedges of anticipated debt refinancings.
(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 June 30, 2016 market interest rates and balances related to our interest rate swaps, a loss of approximately $29 million 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 interest rates change.

ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) as of June 30, 2016. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective at June 30, 2016.

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

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2016, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

On February 12, 2016, our acquisition of SourceGas closed. We are currently in the process of integrating and aligning the operations, processes, and internal controls of the combined company. See Note 2 for more information regarding the acquisition. As permitted by the guidance set forth by the Securities and Exchange Commission, the acquired businesses will not be included in management’s assessment of internal control over financial reporting for the year ending December 31, 2016.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 2015 Annual Report on Form 10-K and Note 18 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 18 is incorporated by reference into this item.

ITEM 1A. Risk Factors

Other than as set forth below, there are no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2015 Annual Report on Form 10-K filed with the SEC.

Oil and Gas

Our inability to successfully transition the Oil and Gas segment to support utility Cost of Service Gas programs may result in additional material impairments of our Oil and Gas assets and could require us to make changes to our business strategy.

In 2015, we began transitioning the Oil and Gas segment to focus primarily on activities supporting utility cost of service gas programs, for our utilities and third-party utilities. The implementation of Cost of Service Gas programs provides a long-term physical hedge for a portion of a utility's gas supply, enhancing the gas supply portfolio and providing longer-term price stability for regulated utility customers. In addition to providing customers the benefits associated with more predictable long-term natural gas prices, it also provides utilities an opportunity to increase earnings through the investment in gas reserves. Cost of Service Gas programs require regulatory approval from state commissions that regulate utility participants in these programs. If these approvals are not obtained, we may have to reconsider our long-term oil and gas strategy which could result in additional impairments of our Oil and Gas assets and could adversely affect the market perception of our business, operating results and stock price.

Risks Related to the SourceGas Acquisition

We recorded goodwill that could become impaired and adversely affect our financial condition and results of operations.

The acquisition of SourceGas was accounted for as a purchase in accordance with GAAP. Under the purchase method of accounting, the assets and liabilities acquired and assumed were recorded at their fair values at the date of acquisition and added to those of Black Hills Corporation. The excess of the purchase price over the estimated fair values was recorded as goodwill. As of June 30, 2016, goodwill totaled $1.3 billion, of which $944 million is attributable to the acquisition of SourceGas.

If we make changes in our business strategy or if market or other conditions adversely affect operations in any of our businesses, we may be forced to record a non-cash impairment charge, which would reduce our reported assets, net income and shareholders' equity. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including: future business operating performance, changes in economic conditions and interest rates, regulatory, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more business segments, which may result in an impairment charge.

Failure to complete future refinancing for our assumed SourceGas debt on favorable terms could have a negative effect on our stock price, and could affect our future business and financial results.

We assumed approximately $760 million of SourceGas's indebtedness, which had terms that are less favorable than we believe we can generally obtain in the debt markets. If we are able to refinance the debt, we will incur transaction costs related to the refinancing, and if we are not able to refinance the debt on more favorable terms, market perception of our business, operating results and stock price could be adversely affected.

Failure to maintain effective internal controls over financial reporting could have a negative effect on our business, operating results and stock price.

Prior to the Acquisition, SourceGas was a private company, exempt from reporting and control requirements under Section 404 of the Sarbanes-Oxley Act of 2002. Section 404 of the Sarbanes-Oxley Act of 2002 requires us to include in our annual report a report containing management's assessment of the effectiveness of our internal controls over financial reporting as of the end of our fiscal year and a statement as to whether or not such internal controls are effective. As permitted by the guidance set forth by the Securities and Exchange Commission, the acquired SourceGas businesses will not be included in management's assessment of internal control over financial reporting for the year ended December 31, 2016.

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. While we expect our control system to adequately integrate the SourceGas processes, we cannot be certain that our current design for internal control over financial reporting, or any additional changes to be made, will be sufficient to enable management to determine that our internal controls are effective for any period, or on an ongoing basis. If we are unable to assert that our internal controls over financial reporting are effective, market perception of our business, operating results and stock price could be adversely affected.

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

There were no unregistered securities sold during the six months ended June 30, 2016.

ITEM 4. Mine Safety Disclosures

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

ITEM 5. Other Information

None.

ITEM 6. Exhibits

Exhibit Number	Description
Exhibit 2.1*	Purchase and Sale Agreement by and among Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer dated as of July 12, 2015 (filed as Exhibit 2.1 to the Registrant's Form 8-K file on July 14, 2015). First Amendment to Purchase and Sale Agreement effective December 10, 2015, by and among, Alinda Gas Delaware LLC, Alinda Infrastructure Fund I L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant’s Form 10-K for 2015).
Exhibit 2.2*	Option Agreement by and among Aircraft Services Corporation, as ASC, SourceGas Holdings LLC, as the Company and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 8-K file on July 14, 2015).
Exhibit 2.3*	Guaranty of Black Hills Corporation in favor of Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, dated as of July 12, 2015 (filed as Exhibit 2.3 to the Registrant's Form 8-K file on July 14, 2015).
Exhibit 3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant’s Form 10-K for 2004).
Exhibit 3.2*	Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant’s Form 8-K filed on February 3, 2010).
Exhibit 4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant’s Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant’s Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant’s Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant’s Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant’s Form 8-K filed on November 18, 2013). Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant’s Form 8-K filed on January 13, 2016).
Exhibit 4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant’s Post-Effective Amendment No. 1 to the Registrant’s Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant’s Post-Effective Amendment No. 1 to the Registrant’s Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant’s Post-Effective Amendment No. 2 to the Registrant’s Registration Statement on Form S-3 (No. 333-150669)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on October 2, 2014).
Exhibit 4.3*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo

	Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014). Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
Exhibit 4.4*	Junior Subordinated Indenture dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on November 23, 2015). First Supplemental Indenture dated as of November 23, 2015 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 23, 2015).

Exhibit 4.5*	Purchase Contract and Pledge Agreement dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as purchase contract agent, collateral agent, custodial agent and securities intermediary (filed as Exhibit 4.4 to the Registrant's Form 8-K filed on November 23, 2015).
Exhibit 4.6*	Indenture dated as of April 16, 2007 between SourceGas LLC and U.S. Bank National Association, as Trustee (relating to $325 million, 5.90% Senior Notes due 2017) (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on March 18, 2016).
Exhibit 4.7*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
Exhibit 12	Computation of Ratio of Earnings to Fixed Charges
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 95	Mine Safety and Health Administration Safety Data.
Exhibit 101	Financial Statements for XBRL Format.

* Previously filed as part of the filing indicated and incorporated by reference herein.
† Indicates a board of director or management compensatory plan.

SIGNATURES

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

BLACK HILLS CORPORATION

/s/ David R. Emery
David R. Emery, Chairman and
Chief Executive Officer

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

Dated: August 4, 2016

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