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	2015	Six Months Ended June 30, 2016	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.

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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:

(in thousands)	For the Three Months Ended June 30, 2015			For the Six Months Ended June 30, 2015		
	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

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)

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(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

(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

(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

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(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

(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.

(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.

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)		$ —

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	$ —	$	