BLACK HILLS CORP /SD/
Form 10-Q
August 04, 2017

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, 2017

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, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	(Do not check if a smaller reporting company)
	Smaller reporting company o
	Emerging growth company o

If an emerging growth company, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section

13(a) of the Exchange Act. o

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes 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, 2017	
Common stock, $1.00 par value	53,475,190	shares

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
APSC	Arkansas Public Service Commission
Arkansas Gas	Black Hills Energy Arkansas, Inc., a direct, wholly-owned subsidiary of Black Hills Gas Inc.
Stockton Storage	Arkansas Gas storage facility
ARMRP	At-Risk Meter Relocation Program
ASC	Accounting Standards Codification
ASU	Accounting Standards Update issued by the FASB
ATM	At-the-market equity offering program
Availability	The availability factor of a power plant is the percentage of the time that it is available to provide energy.
Bbl	Barrel
BHC	Black Hills Corporation; the Company
Black Hills 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
CAPP	Customer Appliance Protection Plan

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 prices and 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)
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
Consolidated Indebtedness to Capitalization Ratio	Any Indebtedness outstanding at such time, divided by Capital at such time. Capital being Consolidated Net-Worth (excluding noncontrolling interest and including the aggregate outstanding amount of RSNs) plus Consolidated Indebtedness (including letters of credit, certain guarantees issued and excluding RSNs) as defined within the current Credit Agreement.
Cooling Degree Day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
Cost of Service Gas Program (COSG)	Proposed Cost of Service Gas Program designed to provide long-term natural gas price stability for the Company’s utility customers, along with a reasonable expectation of customer savings over the life of the program.
CP Program	Commercial Paper Program
CPUC	Colorado Public Utilities Commission
CVA	Credit Valuation Adjustment
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DSM	Demand Side Management
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
ECA	Energy Cost Adjustment - adjustments that allow us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
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
Global Settlement	Settlement with a utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders.
GSRS	Gas System Reliability Surcharge
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

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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)
KCC	Kansas Corporation Commission
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.
MRP	Meter Relocation Program
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)
NOL	Net Operating Loss
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
Revolving Credit Facility	Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2021.
RMNG	Rocky Mountain Natural Gas, a regulated gas utility acquired in the SourceGas Acquisition that provides regulated transmission and wholesale natural gas service to Black Hills Gas in western Colorado (doing business as Black Hills Energy)
RSNs	Remarketable junior subordinated notes, issued on November 23, 2015
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
SourceGas	SourceGas Holdings LLC and its subsidiaries, a gas utility owned by funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co. (NYSE:GE) that was acquired on February 12, 2016, and is now named Black Hills Gas Holdings, LLC (doing business as Black Hills Energy)
SourceGas Acquisition	The acquisition of SourceGas Holdings, LLC by Black Hills Utility Holdings
SourceGas Transaction	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.
South Dakota Electric	Includes Black Hills Power operations in South Dakota, Wyoming and Montana
SSIR	System Safety and Integrity Rider
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
Winter Storm Atlas	An October 2013 blizzard that impacted South Dakota Electric. It was the second most severe blizzard in Rapid City’s history.

WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Wyodak Plant	Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, is owned 80% by Pacificorp and 20% by Black Hills Energy South Dakota. Our WRDC mine supplies all of the fuel for the plant.
Wyoming Electric	Includes Cheyenne Light's electric utility operations
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 CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands, except per share amounts)			
Revenue	$347,978	$325,441	$901,981	$775,400
Operating expenses:				
Fuel, purchased power and cost of natural gas sold	98,164	84,489	317,941	256,345
Operations and maintenance	117,374	112,541	239,504	219,603
Depreciation, depletion and amortization	48,663	47,305	97,310	91,712
Taxes - property, production and severance	13,743	12,760	27,712	24,877
Impairment of long-lived assets	—	25,497	—	39,993
Other operating expenses	1,168	7,551	3,137	33,982
Total operating expenses	279,112	290,143	685,604	666,512
Operating income	68,866	35,298	216,377	108,888
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(35,098)	(34,609)	(70,194)	(66,683)
Allowance for funds used during construction - borrowed	822	754	1,308	1,255
Capitalized interest	130	268	299	503
Interest income	257	946	298	1,601
Allowance for funds used during construction - equity	794	982	1,286	1,689
Other income (expense), net	(58)	(47)	(160)	641
Total other income (expense), net	(33,153)	(31,706)	(67,163)	(60,994)
Income before income taxes	35,713	3,592	149,214	47,894
Income tax benefit (expense)	(10,402)	(309)	(43,757)	(4,561)
Net income	25,311	3,283	105,457	43,333
Net income attributable to noncontrolling interest	(3,116)	(2,614)	(6,739)	(2,662)
Net income available for common stock	$22,195	$669	$98,718	$40,671
Earnings per share of common stock:				
Earnings per share, Basic	$0.42	$0.01	$1.86	$0.79
Earnings per share, Diluted	$0.40	$0.01	$1.79	$0.78
Weighted average common shares outstanding:				
Basic	53,229	51,514	53,191	51,279
Diluted	55,384	52,986	55,179	52,454
Dividends declared per share of common stock	$0.445	$0.420	$0.890	$0.840

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,	
	2017	2016	2017	2016
	(in thousands)			
Net income (loss)	$25,311	$3,283	$105,457	$43,333
Other comprehensive income (loss), net of tax:				
Reclassification adjustments of benefit plan liability - prior service cost (net of tax (expense) benefit of $18 and $19 for the three months ended June 30, 2017 and 2016 and $35 and $38 for the six months ended June 30, 2017 and 2016, respectively)	(31)	(36)	(62)	(72)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(146) and $(173) for the three months ended June 30, 2017 and 2016 and $(300) and $(346) for the six months ended June 30, 2017 and 2016, respectively)	268	321	528	643
Derivative instruments designated as cash flow hedges:				
Net unrealized gains (losses) on interest rate swaps (net of tax of $0 and $4,440 for the three months ended June 30, 2017 and 2016 and $0 and $10,767 for the six months ended June 30, 2017 and 2016, respectively)	—	(8,174)	—	(19,898)
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(249) and $(294) for the three months ended June 30, 2017 and 2016 and $(530) and $(592) for the six months ended June 30, 2017 and 2016, respectively)	464	546	985	1,098
Net unrealized gains (losses) on commodity derivatives (net of tax of $(194) and $906 for the three months ended June 30, 2017 and 2016 and $(536) and $98 for the six months ended June 30, 2017 and 2016, respectively)	331	(1,546)	915	(168)
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $143 and $1,176 for the three months ended June 30, 2017 and 2016 and $249 and $2,476 for the six months ended June 30, 2017 and 2016, respectively)	(243)	(2,050)	(424)	(4,312)
Other comprehensive income (loss), net of tax	789	(10,939)	1,942	(22,709)
Comprehensive income (loss)	26,100	(7,656)	107,399	20,624
Less: comprehensive income attributable to noncontrolling interest	(3,116)	(2,614)	(6,739)	(2,662)
Comprehensive income (loss) available for common stock	$22,984	$(10,270)	$100,660	$17,962

See Note 13 for additional disclosures.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of June 30, 2017	December 31, 2016	June 30, 2016
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$11,590	$13,580	$61,859
Restricted cash and equivalents	2,534	2,274	1,975
Accounts receivable, net	169,957	263,289	150,227
Materials, supplies and fuel	99,126	107,210	85,189
Derivative assets, current	1,148	4,138	4,030
Regulatory assets, current	53,061	49,260	54,856
Other current assets	21,840	27,063	30,652
Total current assets	359,256	466,814	388,788
Investments	12,761	12,561	12,363
Property, plant and equipment	6,533,581	6,412,223	6,209,816
Less: accumulated depreciation and depletion	(1,981,880)	(1,943,234)	(1,819,886)
Total property, plant and equipment, net	4,551,701	4,468,989	4,389,930
Other assets:			
Goodwill	1,299,454	1,299,454	1,303,453
Intangible assets, net	7,972	8,392	9,164
Regulatory assets, non-current	244,099	246,882	220,556
Derivative assets, non-current	37	222	226
Other assets, non-current	13,812	12,130	15,438
Total other assets, non-current	1,565,374	1,567,080	1,548,837
TOTAL ASSETS	$6,489,092	$6,515,444	$6,339,918

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, 2017	December 31, 2016	June 30, 2016
	(in thousands, except share amounts)		
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY			
Current liabilities:			
Accounts payable	$99,970	$153,477	$115,203
Accrued liabilities	201,993	244,034	218,250
Derivative liabilities, current	719	2,459	28,855
Accrued income taxes, net	5,160	12,552	10,624
Regulatory liabilities, current	17,305	13,067	34,275
Notes payable	107,975	96,600	75,000
Current maturities of long-term debt	5,743	5,743	930,743
Total current liabilities	438,865	527,932	1,412,950
Long-term debt	3,160,302	3,211,189	2,221,347
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	589,189	535,606	530,746
Derivative liabilities, non-current	88	274	231
Regulatory liabilities, non-current	199,005	193,689	195,166
Benefit plan liabilities	176,102	173,682	173,347
Other deferred credits and other liabilities	135,510	138,643	122,015
Total deferred credits and other liabilities	1,099,894	1,041,894	1,021,505
Commitments and contingencies (See Notes 8, 10, 15, 16)			
Redeemable noncontrolling interest	—	4,295	4,171
Equity:			
Stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 53,513,521; 53,397,467; and 52,299,075 shares, respectively	53,514	53,397	52,299
Additional paid-in capital	1,145,493	1,138,982	1,072,927
Retained earnings	512,498	457,934	469,940
Treasury stock, at cost – 39,329; 15,258; and 18,900 shares, respectively	(2,325)	(791)	(975)
Accumulated other comprehensive income (loss)	(32,941)	(34,883)	(31,764)
Total stockholders' equity	1,676,239	1,614,639	1,562,427
Noncontrolling interest	113,792	115,495	117,518
Total equity	1,790,031	1,730,134	1,679,945
TOTAL LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY	$6,489,092	$6,515,444	$6,339,918

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Six Months Ended June 30,	
	2017	2016
Operating activities:	(in thousands)	
Net income (loss)	$105,457	$40,671
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	97,310	91,712
Deferred financing cost amortization	4,138	2,857
Impairment of long-lived assets	—	39,993
Stock compensation	6,589	7,054
Deferred income taxes	51,153	32,606
Employee benefit plans	5,717	7,782
Other adjustments, net	(6,515)	(6,332)
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	7,720	17,722
Accounts receivable, unbilled revenues and other operating assets	97,902	82,361
Accounts payable and other operating liabilities	(113,541)	(124,695)
Regulatory assets - current	3,086	1,862
Regulatory liabilities - current	5,908	2,994
Contributions to defined benefit pension plans	—	(10,200)
Other operating activities, net	(2,055)	(2,884)
Net cash provided by (used in) operating activities	262,869	183,503
Investing activities:		
Property, plant and equipment additions	(163,768)	(199,854)
Acquisition, net of long term debt assumed	—	(1,124,238)
Other investing activities	(22)	(649)
Net cash provided by (used in) investing activities	(163,790)	(1,324,741)
Financing activities:		
Dividends paid on common stock	(47,544)	(43,265)
Common stock issued	2,965	57,490
Sale of noncontrolling interest	—	216,370
Net (payments) borrowings of short-term debt	11,375	(1,800)
Long-term debt - issuances	—	574,672
Long-term debt - repayments	(52,871)	(41,436)
Distributions to noncontrolling interest	(8,335)	—
Other financing activities	(6,659)	205
Net cash provided by (used in) financing activities	(101,069)	762,236
Net change in cash and cash equivalents	(1,990)	(379,002)
Cash and cash equivalents, beginning of period	13,580	440,861
Cash and cash equivalents, end of period	$11,590	$61,859

See Note 14 for supplemental disclosure of cash flow information.

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

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company’s 2016 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 2016 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.

Use of Estimates and Basis of Presentation

The information furnished in the accompanying Condensed Consolidated Financial Statements reflects certain estimates required and all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the June 30, 2017, December 31, 2016, and June 30, 2016 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, 2017 and June 30, 2016, and our financial condition as of June 30, 2017, December 31, 2016, and June 30, 2016, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. June 30, 2017 reflects a full six months of activity from the SourceGas Acquisition on February 12, 2016, as compared to the six months ended June 30, 2016 which reflects a partial period of approximately 4.5 months. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

Revisions

Certain revisions have been made to prior years’ financial information to conform to the current year presentation. The Company revised its presentation of cash as of December 31, 2016. The Company has banking arrangements at certain financial institutions whereby if required, payments of one account are cleared with cash from other accounts at the same financial institution; therefore, book overdrafts are presented on a combined basis by bank as cash and cash equivalents. Prior year amounts were corrected to conform with the current year presentation, which decreased cash and cash equivalents and accounts payable by $55 million as of June 30, 2016, and decreased net cash flows provided by operations by $39 million for the six months ended June 30, 2016. We assessed the materiality of these changes, taking into account quantitative and qualitative factors, and determined them to be immaterial to the condensed consolidated balance sheet as of June 30, 2016 and to the Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2016. There is no impact to the Condensed Consolidated Statements of Income or the Condensed Consolidated Statements of Comprehensive Income for any period reported.

Recently Issued and Adopted Accounting Standards

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

In March 2017, the FASB issued ASU 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost. The changes to the standard require employers to report the service cost component in the same line item(s) as other compensation costs, and require the other components of net periodic pension and post-retirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component may be eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. This ASU will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and post-retirement benefit costs in the income statement. The capitalization of the service cost component of net period pension and post-retirement benefit costs in assets will be applied on a prospective basis. This new guidance is effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. We continue to assess the impact of this new standard on our financial statements and disclosures, and we monitor regulated utility industry implementation discussions and guidance. The presentation changes required for net periodic pension and post-retirement costs will result in offsetting changes to Operating income and Other income and are not expected to be material. We will implement this standard effective January 1, 2018.

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

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

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

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting. This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early adoption permitted. Certain amendments of this guidance are to be applied retrospectively and others prospectively. We implemented this ASU effective January 1, 2017, recording a cumulative-effect adjustment to retained earnings as of the date of adoption of $3.2 million in the Condensed Consolidated Balance Sheets, representing previously recorded forfeitures and excess tax benefits generated in years prior to 2017 that were previously not recognized in stockholders’ equity due to NOLs in those years. Adoption of this ASU did not have a material impact on our consolidated financial position, results of operations or 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 on the balance sheet for all leases with a term greater than 12 months, whereas today only financing type lease liabilities (capital leases) are recognized on the balance sheet. In addition, the definition of a lease has been revised in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement which may result in changes to the classification of an arrangement as a lease. The ASU does not significantly change the lessees' recognition, measurement and presentation of expenses and cash flows from the previous accounting standard. Lessors' accounting under the ASU is largely unchanged from the previous accounting standard. The ASU expands the disclosure requirements of lease arrangements. Lessees and lessors will use a modified retrospective transition approach, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. The guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted.

We currently expect to adopt this standard on January 1, 2019. We continue to evaluate the impact of this new standard on our financial position, results of operations and cash flows as well as monitor emerging guidance on such topics as easements and right of ways, pipeline laterals, purchase power agreements, pole attachments and other industry-related areas. We also expect to implement changes to systems, processes and procedures in order to recognize and measure leases recorded on the balance sheet that are currently classified as operating leases.

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. The new disclosure requirements will provide information about the nature, amount, timing and uncertainty of revenue and cash flows from revenue contracts with customers. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017 with early adoption on January 1, 2017 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 currently expect to implement the standard on a modified retrospective basis effective January 1, 2018. We continue to actively assess all of our sources of revenue to determine the impact that adoption of the new standard will have on our financial position, results of operations and cash flows. Our evaluation includes identifying revenue streams by like contracts to allow for ease of implementation. A majority of our revenues are from regulated tariff offerings that provide natural gas or electricity with a defined contractual term. For such arrangements, we expect that revenue from contracts with the customer will be equivalent to the electricity or gas delivered in that period. Therefore, we do not expect there will be a significant shift in the timing or pattern of revenue recognition for regulated tariff based sales. The evaluation of other revenue streams is ongoing, including our non-regulated revenues and those tied to longer term contractual commitments. We also continue to monitor outstanding industry implementation issues and assess the impacts to our current accounting policies and/or patterns of revenue recognition.

(2) ACQUISITION

2016 Acquisition of SourceGas

On February 12, 2016, Black Hills Corporation acquired SourceGas (now referred to as Black Hills Gas Holdings). We acquired SourceGas for $1.1 billion of cash plus the assumption of $760 million of long-term debt. We finalized our purchase price allocation at December 31, 2016. See Note 2 of our Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K for more details.

Pro Forma Results

The following unaudited pro forma financial information reflects the consolidated results of operations as if the SourceGas Acquisition had taken place on January 1, 2015. The unaudited pro forma financial information is presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or our future consolidated results.

The pro forma financial information does not reflect any potential cost savings from operating efficiencies resulting from the acquisition and does not include certain acquisition-related costs 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 exclude approximately $4.0 million and $20 million, respectively, of after-tax transaction costs, professional fees, employee related expenses and other miscellaneous costs.

	Three Months Ended June 30, 2016	Six Months Ended June 30, 2016
	(in thousands, except per share amounts)	
Revenue	$325,441	$854,362
Net income (loss) available for common stock	$4,658	$72,978
Earnings (loss) per share, Basic	$0.09	$1.42
Earnings (loss) per share, Diluted	$0.09	$1.39

Redemption of seller’s noncontrolling interest

As part of the SourceGas Transaction, a seller retained a 0.5% noncontrolling interest and we entered into an associated option agreement with the holder of the 0.5% retained interest. The terms of the agreement provided us a call option to purchase the remaining interest beginning 366 days after the initial close of the SourceGas Transaction. In March 2017, we exercised our call option and purchased the remaining 0.5% equity interest in SourceGas for $5.6 million.

(3) BUSINESS SEGMENT INFORMATION

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

Three Months Ended June 30, 2017	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$165,517	$ 2,936	$18,832
Gas	166,439	8	(272)
Power Generation [b]	1,470	20,325	5,332
Mining	8,403	6,543	2,681
Oil and Gas	6,149	—	(1,946)
Corporate activities [c]	—	—	(2,432)
Inter-company eliminations	—	(29,812)	—
Total	$347,978	$ —	$22,195

Three Months Ended June 30, 2016	External	Inter-company

	Operating Revenue	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 (b)	1,546	20,168	5,683
Mining	3,922	7,125	724
Oil and Gas (e)	7,646	—	(19,424)
Corporate activities (c)	—	—	(6,530)
Inter-company eliminations	—	(28,408)	—
Total	$ 325,441	$ —	$ 669

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Six Months Ended June 30, 2017	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$337,687	$ 6,790	$41,062
Gas [(a)]	531,340	17	45,738
Power Generation [(b)]	3,572	41,790	11,862
Mining	16,758	14,734	5,571
Oil and Gas	12,624	—	(4,897)
Corporate activities [(c)(d)]	—	—	(618)
Inter-company eliminations	—	(63,331)	—
Total	$901,981	$ —	$98,718

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 [(a)]	422,434	—	32,914
Power Generation [(b)]	3,398	41,624	14,265
Mining	11,456	15,873	3,662
Oil and Gas [(e)]	16,021	—	(26,448)
Corporate activities [(c)(d)]	—	—	(22,166)
Inter-company eliminations	—	(64,163)	—
Total	$775,400	$ —	$40,671

(a) Gas Utility revenue increased for the six months ended June 30, 2017 compared to the same periods in the prior year primarily due to the addition of the SourceGas utilities on February 12, 2016.

(b) Net income (loss) available for common stock for the three and six months ended June 30, 2017 was net of net income attributable to noncontrolling interests of $3.1 million and $6.6 million, respectively, and $2.6 million for both the three and six months ended June 30, 2016.

(c) Net income (loss) available for common stock for the three and six months ended June 30, 2017 and June 30, 2016 included incremental, non-recurring acquisition costs, net of tax of $0.3 million and $1.2 million, and $4.1 million and $20 million respectively. The three and six months ended June 30, 2016 also included $2.0 million and $5.7 million, respectively, of after-tax internal labor costs attributable to the acquisition.

(d) Net income (loss) available for common stock for the six months ended June 30, 2017 included a $1.4 million tax benefit recognized from carryback claims for specified liability losses involving prior tax years. Net income (loss) available for common stock for the six months ended June 30, 2016 included tax benefits of approximately $4.4 million as a result of the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016. See Note 18.

(e) Net income (loss) available for common stock for the three and six months ended June 30, 2016 included non-cash after-tax impairments of oil and gas properties of $16 million and $25 million. See Note 17 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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, 2017	December 31, 2016	June 30, 2016
Segment:			
Electric [(a)]	$2,901,570	$2,859,559	$2,755,695
Gas	3,242,461	3,307,967	3,118,626
Power Generation [(a)]	66,292	73,445	80,360
Mining	67,365	67,347	71,319
Oil and Gas [(b)]	103,044	96,435	171,239
Corporate activities	108,360	110,691	142,679
Total assets	$6,489,092	$6,515,444	$6,339,918

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

(b) As a result of continued low commodity prices and our decision to divest non-core oil and gas assets, we recorded non-cash impairments of $107 million for the year ended December 31, 2016 and $40 million for the six months ended June 30, 2016. See Note 17 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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(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, 2017	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 41,635	$ 33,686	$ (466)	$ 74,855
Gas Utilities	62,908	26,584	(2,535)	86,957
Power Generation	877	—	—	877
Mining	2,904	—	—	2,904
Oil and Gas	3,280	—	(83)	3,197
Corporate	1,167	—	—	1,167
Total	$ 112,771	$ 60,270	$ (3,084)	$ 169,957

December 31, 2016	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 41,730	$ 36,463	$ (353)	$ 77,840
Gas Utilities	88,168	88,329	(2,026)	174,471
Power Generation	1,420	—	—	1,420
Mining	3,352	—	—	3,352
Oil and Gas	3,991	—	(13)	3,978
Corporate	2,228	—	—	2,228
Total	$ 140,889	$ 124,792	$ (2,392)	$ 263,289

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

(5) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of June 30, 2017	As of December 31, 2016	As of June 30, 2016
Regulatory assets				
Deferred energy and fuel cost adjustments - current [(a)(d)]	1	$20,761	$17,491	$20,603
Deferred gas cost adjustments [(a)(d)]	1	9,060	15,329	12,122
Gas price derivatives [(a)]	3.5	11,159	8,843	11,515
Deferred taxes on AFUDC [(b)]	45	15,322	15,227	13,879
Employee benefit plans [(c)]	12	107,419	108,556	109,522
Environmental [(a)]	subject to approval	1,070	1,108	1,144
Asset retirement obligations [(a)]	44	510	505	505
Loss on reacquired debt [(a)]	30	21,466	22,266	3,061
Renewable energy standard adjustment [(b)]	5	768	1,605	2,679
Deferred taxes on flow through accounting [(c)]	35	40,586	37,498	31,554
Decommissioning costs [(e)]	6	14,681	16,859	18,399
Gas supply contract termination	5	22,793	26,666	28,385
Other regulatory assets [(a) (e)]	15	31,565	24,189	22,044
		$297,160	$296,142	$275,412
Regulatory liabilities				
Deferred energy and gas costs [(a) (d)]	1	$16,767	$10,368	$32,868
Employee benefit plan costs and related deferred taxes [(c)]	12	67,297	68,654	62,712
Cost of removal [(a)]	44	125,247	118,410	126,002
Revenue subject to refund	1	1,518	2,485	1,616
Other regulatory liabilities [(c)]	25	5,481	6,839	6,243
		$216,310	$206,756	$229,441

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

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

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

(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) In accordance with a settlement agreement approved by the SDPUC on June 16, 2017, the amortization of South Dakota Electric's decommissioning costs of approximately $11 million, vegetation management costs of approximately $14 million, and Winter Storm Atlas costs of approximately $2.0 million will be amortized over 6 years, effective July 1, 2017. Decommissioning costs and Winter Storm Atlas costs were previously amortized over a 10 year period ending September 30, 2024. The vegetation management costs were previously unamortized. The change in amortization periods for these costs will increase annual amortization expense by approximately $2.7 million.

(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, 2017	December 31, 2016	June 30, 2016
Materials and supplies	$72,397	$68,456	$67,440
Fuel - Electric Utilities	3,106	3,667	4,659
Natural gas in storage held for distribution	23,623	35,087	13,090
Total materials, supplies and fuel	$99,126	$107,210	$85,189

(7) EARNINGS PER SHARE

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Net income (loss) available for common stock	$22,195	$ 669	$98,718	$40,671
Weighted average shares - basic	53,229	51,514	53,191	51,279
Dilutive effect of:				
Equity Units [(a)]	1,977	1,362	1,796	1,068
Equity compensation	178	110	192	107
Weighted average shares - diluted	55,384	52,986	55,179	52,454

(a) Calculated using the treasury stock method.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Equity compensation	—	4	—	10
Anti-dilutive shares	—	4	—	10

(8) NOTES PAYABLE AND LONG-TERM DEBT

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

	June 30, 2017		December 31, 2016		June 30, 2016	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$—	$24,540	$96,600	$36,000	$75,000	$24,700
CP Program	107,975	—	—	—	—	—
Total	$107,975	$24,540	$96,600	$36,000	$75,000	$24,700

Revolving Credit Facility and CP Program

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extend the term through August 9, 2021 with two one-year extension options (subject to consent from lenders). This facility is similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase total commitments of the facility up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from either S&P or Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.250%, 1.250%, and 1.250%, respectively, at June 30, 2017. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

On December 22, 2016, we implemented a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption. Our net amount borrowed under the CP Program during the six months ended June 30, 2017 and our notes outstanding as of June 30, 2017 were $108 million. As of June 30, 2017, the weighted average interest rate on CP Program borrowings was 1.41%.

Debt Covenants

On December 7, 2016, we amended our Revolving Credit Facility and term loan agreements, allowing the exclusion of the Remarketable Junior Subordinated Notes (RSNs) from our Consolidated Indebtedness to Capitalization Ratio covenant calculation. Under the amended and restated Revolving Credit Facility and term loan agreements, we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. Our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit and certain guarantees issued and excludes RSNs by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs.

Our Revolving Credit Facility and our Term Loans require compliance with the following financial covenant at the end of each quarter:

	As of June 30, 2017	Covenant Requirement
Consolidated Indebtedness to Capitalization Ratio	61%	Less than 65%

As of June 30, 2017, we were in compliance with this covenant.

Long-Term Debt

On May 16, 2017, we paid down $50 million on our Corporate term loan due August 9, 2019. On July 17, 2017, we paid down an additional $50 million on the same term loan. Short-term borrowings from our CP program were used to fund the payments on the Corporate term loan.

(9) EQUITY

A summary of the changes in equity is as follows:

Six Months Ended June 30, 2017	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
		(in thousands)	
Balance at December 31, 2016	$ 1,614,639	$ 115,495	$ 1,730,134
Net income (loss)	98,718	6,632	105,350
Other comprehensive income (loss)	1,942	—	1,942
Dividends on common stock	(47,544)	—	(47,544)
Share-based compensation	4,133	—	4,133
Issuance of common stock	—	—	—
Dividend reinvestment and stock purchase plan	1,530	—	1,530
Redeemable noncontrolling interest	(886)	—	(886)
Cumulative effect of ASU 2016-09 implementation	3,714	—	3,714
Other stock transactions	(7)	—	(7)
Distribution to noncontrolling interest	—	(8,335)	(8,335)
Balance at June 30, 2017	$ 1,676,239	$ 113,792	$ 1,790,031

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

At-the-Market Equity Offering Program

On March 18, 2016, we implemented an ATM equity offering program allowing us to sell shares of our common stock with an aggregate value of up to $200 million. The shares may be offered from time to time pursuant to a sales agreement dated March 18, 2016. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. We did not issue any common shares during the six months ended June 30, 2017. 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. During the six months ended June 30, 2016, we 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 with settlement dates through June 30, 2016. On August 4, 2017, the Company plans to file for renewal of the ATM equity offering program initiated in 2016 which resets the size of the ATM equity offering program to an aggregate sales price of up to $300 million.

Sale of Noncontrolling Interest in Subsidiary

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

This partial sale was required to be recorded as an equity transaction with no resulting gain or loss on the sale. Further, 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, 2017	December 31, 2016	June 30, 2016
	(in thousands)		
Assets			
Current assets	$12,042	$12,627	$12,681
Property, plant and equipment of variable interest entities, net	$214,239	$218,798	$224,128
Liabilities			
Current liabilities	$2,651	$4,342	$4,174

(10) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures as discussed in our 2016 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.

Credit Risk

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

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

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

Our derivative and hedging activities recorded in the accompanying Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Income and Condensed Consolidated Statements of Comprehensive Income are detailed below and in Note 11.

Oil and Gas

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

To mitigate commodity price risk and preserve cash flows, we primarily use exchange traded futures, swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on our futures and swaps. 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.

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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, 2017			December 31, 2016			June 30, 2016	
	Crude Oil Futures	Crude Oil Options	Natural Gas Futures and Swaps	Crude Oil Futures	Crude Oil Options	Natural Gas Futures and Swaps	Crude Oil Futures	Natural Gas Futures and Swaps
Notional [(a)]	72,000	18,000	1,080,000	108,000	36,000	2,700,000	210,000	2,530,000
Maximum terms in months [(b)]	18	6	6	24	12	12	30	18

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(a) Crude oil futures and call options in Bbls, natural gas in MMBtus.
(b) Term reflects the maximum forward period hedged.

Based on June 30, 2017 prices, a $0.5 million gain would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

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, or the Condensed Consolidated Statements of Comprehensive Income.

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from July 2017 through December 2020. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with forward contracts to deliver gas to our Choice Gas Program customers. The effective portion of the gain or loss on these designated derivatives is reported in AOCI in the accompanying Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Fuel, purchased power and cost of natural gas sold in the accompanying Condensed Consolidated Statements of Income. Effectiveness of our hedging position is evaluated at least quarterly.

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, 2017		December 31, 2016		June 30, 2016	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	11,060,000	42	14,770,000	48	18,080,000	54
Natural gas options purchased, net	1,640,000	20	3,020,000	5	3,770,000	20
Natural gas basis swaps purchased	10,070,000	42	12,250,000	48	15,320,000	54
Natural gas over-the-counter swaps, net [(b)]	5,200,000	23	4,622,302	28	5,029,500	23
Natural gas physical contracts, net	8,427,119	10	21,504,378	10	1,666,800	9

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(a) Term reflects the maximum forward period hedged.
(b) 2,480,000 MMBtus were designated as cash flow hedges for the natural gas fixed for float swaps purchased.

Based on June 30, 2017 prices, a $0.2 million loss would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

Financing Activities

In October 2015 and January 2016, we entered into forward starting interest rate swaps with a notional value totaling $400 million to reduce the interest rate risk associated with the anticipated issuance of senior notes. These swaps were settled at a loss of $29 million in connection with the issuance of our $400 million of unsecured ten-year senior notes on August 10, 2016. The effective portion of the loss in the amount of $28 million was recognized as a component of AOCI and will be recognized as a component of interest expense over the ten-year life of the $400 million unsecured senior note issued on August 19, 2016. Amortization of approximately $2.9 million, which includes the amortization of the $28 million loss currently deferred in AOCI will be recognized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. The ineffective portion of $1.0 million, related to the timing of the debt issuance, was recognized in earnings as a component of interest expense in 2016. 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, 2017	December 31, 2016	June 30, 2016		
	Designated Interest Rate Swaps	Designated Interest Rate Swap [(a)]	Designated Interest Rate Swap [(b)]	Designated Interest Rate Swap [(b)]	Designated Interest Rate Swaps [(a)]
Notional	$ —	$ 50,000	$ 150,000	$ 250,000	$ 75,000
Weighted average fixed interest rate	— %	4.94 %	2.09 %	2.29 %	4.97 %
Maximum terms in months	0	1	10	10	6
Derivative liabilities, current	$ —	$ 90	$ 8,553	$ 18,500	$ 1,505

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(a) The $25 million in swaps expired in October 2016 and the $50 million in swaps expired in January 2017. These swaps were designated to borrowings on our Revolving Credit Facility and were priced using three-month LIBOR, matching the floating portion of the related borrowings.
(b) These swaps were settled and terminated in August 2016 in conjunction with the refinancing of acquired SourceGas debt.

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Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income is presented below for the three and six months ended June 30, 2017 and 2016 (in thousands). Note that this presentation does not reflect gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

Three Months Ended June 30, 2017

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (713)	Interest expense	$ —
Commodity derivatives	Revenue	430	Revenue	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(44)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (327)		$ —

Three Months Ended June 30, 2016

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (840)	Interest expense	$ —
Commodity derivatives	Revenue	3,287	Revenue	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(61)	Fuel, purchased power and cost of natural gas sold	—
Total		$ 2,386		$ —

Six Months Ended June 30, 2017

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

				Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (1,515)	Interest expense	$ —
Commodity derivatives	Revenue	659	Revenue	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	14	Fuel, purchased power and cost of natural gas sold	—
Total		$ (842)		$ —

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Six Months Ended June 30, 2016

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (1,690)	Interest expense	$ —
Commodity derivatives	Revenue	6,939	Revenue	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(151)	Fuel, purchased power and cost of natural gas sold	—
Total		$ 5,098		$ —

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss) for the three and six months ended June 30, 2017 and 2016. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the Consolidated Statements of Net Income as incurred.

	Three Months Ended June 30,	
	2017	2016
	(In thousands)	
Increase (decrease) in fair value:		
Interest rate swaps	$—	$(12,614)
Forward commodity contracts	525	(2,452)
Recognition of (gains) losses in earnings due to settlements:		
Interest rate swaps	713	840
Forward commodity contracts	(386)	(3,226)
Total other comprehensive income (loss) from hedging	$852	$(17,452)

	Six Months Ended June 30,	
	2017	2016
	(In thousands)	
Increase (decrease) in fair value:		
Interest rate swaps	$—	$(30,665)
Forward commodity contracts	1,451	(266)
Recognition of (gains) losses in earnings due to settlements:		
Interest rate swaps	1,515	1,690
Forward commodity contracts	(673)	6,788
Total other comprehensive income (loss) from hedging	$2,293	$(22,453)

Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income for the three and six months ended June 30, 2017 and 2016 (in thousands). Note that this presentation does not reflect gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

		Three Months Ended June 30,	
		2017	2016
Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Revenue	$26	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(691)	2,201
		$(665)	$ 2,201

		Six Months Ended June 30,	
		2017	2016
Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Revenue	$143	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(1,500)	2,835
		$(1,357)	$ 2,835

As discussed above, financial instruments used in our regulated utilities are not designated as cash flow hedges. However, there is no earnings impact because the unrealized gains and losses arising from the use of these financial instruments are recorded as Regulatory assets. The net unrealized losses included in our Regulatory assets related to the hedges in our Utilities were $11 million, $8.8 million and $12 million at June 30, 2017, December 31, 2016 and June 30, 2016, respectively.

(11) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

The accounting guidance for fair value measurements requires certain disclosures about assets and liabilities measured at fair value. This guidance establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments. For additional information, see Notes 1, 9, 10 and 11 to the Consolidated Financial Statements included in our 2016 Annual Report on Form 10-K filed with the SEC.

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

Valuation Methodologies for Derivatives

Oil and Gas Segment:

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

Utilities Segments:

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

- As of June 30, 2017, we no longer have derivatives within our corporate activities as our interest rate swaps matured in January 2017. The interest rate swaps that were in place prior to January 2017 were valued using the market approach. We established fair value by obtaining price quotes directly from the counterparty which were based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty was 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 included a CVA component. The CVA considered 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 utilized 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 took 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, 2017				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 770	$ —	$ (230)	$ 540
Commodity derivatives — Utilities	—	1,622	—	(977)	645
Total	$ —	$ 2,392	$ —	$ (1,207)	$ 1,185
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 44	$ —	$ —	$ 44
Commodity derivatives — Utilities	—	12,331	—	(11,568)	763
Total	$ —	$ 12,375	$ —	$ (11,568)	$ 807

	As of December 31, 2016				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 2,886	$ —	$ (2,733)	$ 153
Commodity derivatives —Utilities	—	7,469	—	(3,262)	4,207
Total	$ —	$ 10,355	$ —	$ (5,995)	$ 4,360
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 1,586	$ —	$ —	$ 1,586
Commodity derivatives — Utilities	—	12,201	—	(11,144)	1,057
Interest rate swaps	—	90	—	—	90
Total	$ —	$ 13,877	$ —	$ (11,144)	$ 2,733

	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	$ —	$ 2,748	$ —	$ (1,150)	$ 1,598
Commodity derivatives — Utilities	—	6,833	—	(4,175)	2,658
Total	$ —	$ 9,581	$ —	$ (5,325)	$ 4,256
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 228	$ —	$ —	$ 228
Commodity derivatives — Utilities	—	14,727	—	(14,427)	300
Interest rate swaps	—	28,558	—	—	28,558
Total	$ —	$ 43,513	$ —	$ (14,427)	$ 29,086

Fair Value Measures by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis aside from the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements and the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions.

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

As of June 30, 2017

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 548	$ —
Commodity derivatives	Derivative assets — non-current	31	—
Commodity derivatives	Derivative liabilities — current	—	167
Commodity derivatives	Derivative liabilities — non-current	—	32
Total derivatives designated as hedges		$ 579	$ 199
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 600	$ —
Commodity derivatives	Derivative assets — non-current	6	—
Commodity derivatives	Derivative liabilities — current	—	552
Commodity derivatives	Derivative liabilities — non-current	—	56
Total derivatives not designated as hedges		$ 606	$ 608

As of December 31, 2016

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 1,161	$ —
Commodity derivatives	Derivative assets — non-current	124	—
Commodity derivatives	Derivative liabilities — current	—	1,090
Commodity derivatives	Derivative liabilities — non-current	—	238
Interest rate swaps	Derivative liabilities — current	—	90
Total derivatives designated as hedges		$ 1,285	$ 1,418
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 2,977	$ —
Commodity derivatives	Derivative assets — non-current	98	—
Commodity derivatives	Derivative liabilities — current	—	1,279
Commodity derivatives	Derivative liabilities — non-current	—	36
Total derivatives not designated as hedges		$ 3,075	$ 1,315

As of June 30, 2016

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

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about the fair value measurements of their assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 18 to the Consolidated Financial Statements included in our 2016 Annual Report on Form 10-K.

(12) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 11, were as follows (in thousands) as of:

	June 30, 2017		December 31, 2016		June 30, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$11,590	$11,590	$13,580	$13,580	$61,859	$61,859
Restricted cash and equivalents [(a)]	$2,534	$2,534	$2,274	$2,274	$1,975	$1,975
Notes payable [(b)]	$107,975	$107,975	$96,600	$96,600	$75,000	$75,000
Long-term debt, including current maturities, net of deferred financing costs [(c)]	$3,166,045	$3,377,891	$3,216,932	$3,351,305	$3,152,090	$3,427,587

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

(b) Notes payable consist of commercial paper borrowings and borrowings on our Revolving Credit Facility. Carrying value approximates fair value due to the short-term length of maturity; since these borrowings are not traded on an exchange, they are classified in Level 2 in the fair value hierarchy.

(c) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

(13) OTHER COMPREHENSIVE INCOME (LOSS)

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges, commodity contracts designated as cash flow hedges and the amortization of components of our defined benefit plans. Deferred gains (losses) for our commodity contracts designated as cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate swaps are recognized in earnings as they are amortized.

The following table details reclassifications out of AOCI and into net income. The amounts in parentheses below indicate decreases to net income in the Consolidated Statements of Income for the period, net of tax (in thousands):

		Amount Reclassified from AOCI			
	Location on the Condensed Consolidated Statements of Income	Three months ended		Six Months Ended	
		June 30, 2017	June 30, 2016	June 30, 2017	June 30, 2016
Gains and (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$(713)	$(840)	$(1,515)	$(1,690)
Commodity contracts	Revenue	430	3,287	659	6,939
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(44)	(61)	14	(151)
		(327)	2,386	(842)	5,098
Income tax	Income tax benefit (expense)	106	(882)	281	(1,884)
Total reclassification adjustments related to cash flow hedges, net of tax		$(221)	$1,504	$(561)	$3,214

Amortization of components of defined benefit plans:

Prior service cost	Operations and maintenance	$49	$55	$97	$110
Actuarial gain (loss)	Operations and maintenance	(414)	(494)	(828)	(989)
		(365)	(439)	(731)	(879)
Income tax	Income tax benefit (expense)	128	154	265	308
Total reclassification adjustments related to defined benefit plans, net of tax		$(237)	$(285)	$(466)	$(571)
Total reclassifications		$(458)	$1,219	$(1,027)	$2,643

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Balances by classification included within AOCI, net of tax on the accompanying Condensed Consolidated Balance Sheets were as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2016	$(18,109)	$ (233)	$(16,541)	$(34,883)
Other comprehensive income (loss) before reclassifications	—	915	—	915
Amounts reclassified from AOCI	985	(424)	466	1,027
Ending Balance June 30, 2017	$(17,124)	$ 258	$(16,075)	$(32,941)

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
Balance as of December 31, 2015	$(341)	$ 7,066	$(15,780)	$(9,055)
Other comprehensive income (loss) before reclassifications	(19,898)	(168)	—	(20,066)
Amounts reclassified from AOCI	1,098	(4,312)	571	(2,643)
Ending Balance June 30, 2016	$(19,141)	$ 2,586	$(15,209)	$(31,764)

(14) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Six Months Ended	June 30, 2017	June 30, 2016
	(in thousands)	
Non-cash investing and financing activities—		
Property, plant and equipment acquired with accrued liabilities	$37,601	$52,917
Cash (paid) refunded during the period —		
Interest (net of amounts capitalized)	$(65,820)	$(48,139)
Income taxes, net	$1	$(1,162)

(15) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Service cost	$1,759	$2,078	$3,517	$4,156
Interest cost	3,880	3,936	7,760	7,872
Expected return on plan assets	(6,129)	(5,766)	(12,258)	(11,531)
Prior service cost	15	15	29	30
Net loss (gain)	1,001	1,793	2,003	3,586
Net periodic benefit cost	$526	$2,056	$1,051	$4,113

Defined Benefit Postretirement Healthcare Plans

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Service cost	$575	$467	$1,150	$934
Interest cost	534	485	1,067	970
Expected return on plan assets	(79)	(70)	(158)	(140)
Prior service cost (benefit)	(109)	(107)	(218)	(214)
Net loss (gain)	125	84	250	168
Net periodic benefit cost	$1,046	$859	$2,091	$1,718

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

The components of net periodic benefit cost for the Supplemental Non-qualified Defined Benefit and Defined Contribution Plans were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Service cost	$609	$878	$1,436	$907
Interest cost	319	315	638	629
Prior service cost	—	1	1	1
Net loss (gain)	250	207	500	414
Net periodic benefit cost	$1,178	$1,401	$2,575	$1,951

Contributions

Contributions to the Defined Benefit Pension Plan are cash contributions made directly to the Pension Plan Trust accounts. On July 24, 2017, we made contributions to the Defined Benefit Pension Plan in the amount of approximately $13 million. Contributions to the Healthcare and Supplemental Plans are made in the form of benefit payments. Contributions made in 2017 and anticipated contributions for 2017 and 2018 are as follows (in thousands):

	Contributions Made	Contributions Made	Additional Contributions	Contributions
	Three Months Ended June 30, 2017	Six Months Ended June 30, 2017	Anticipated for 2017	Anticipated for 2018
Defined Benefit Pension Plan	$ —	$ —	$ 12,700	$ 12,700
Non-pension Defined Benefit Postretirement Healthcare Plans	$ 1,270	$ 2,540	$ 2,540	$ 5,115
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$ 396	$ 792	$ 792	$ 1,682

(16) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K except for those described below.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of June 30, 2017, we were in compliance with the debt covenants.

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

Our utilities are generally limited to the amount of dividends allowed to be paid to us as a utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions and financing agreements. As of June 30, 2017, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

(17) IMPAIRMENT OF ASSETS

Long-lived Assets

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

There were no impairments for the six months ended June 30, 2017. In determining the ceiling value of our assets under the full cost accounting rules of the SEC, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. At June 30, 2017, the average NYMEX natural gas price was $3.01 per Mcf, adjusted to $2.70 per Mcf at the wellhead; the average NYMEX crude oil price was $48.95 per barrel, adjusted to $44.42 per barrel at the wellhead. At June 30, 2016, the average NYMEX natural gas price was $2.24 per Mcf, adjusted to $1.01 per Mcf at the wellhead; the average NYMEX crude oil price was $43.12 per barrel, adjusted to $37.19 per barrel at the wellhead. During the three and six months ended June 30, 2016, we recorded pre-tax non-cash impairments of oil and gas assets included in our Oil and Gas segment of $11 million and $25 million, respectively.

During the second quarter of 2016, in advancing our Oil and Gas strategy, certain non-core assets were identified that are not suitable for inclusion in a possible Cost of Service Gas program. We assessed these assets for impairment in accordance with ASC 360. We valued the assets applying a market method approach utilizing assumptions consistent with similar known and measurable transactions and determined that the carrying amount exceeded the fair value. As a result, we recorded a pre-tax impairment of depreciable properties at June 30, 2016 of $14 million, in addition to the impairments noted above.

(18) INCOME TAXES

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

	Three Months Ended June 30,	
Tax (benefit) expense	2017	2016
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect) [(a)]	(0.1)	16.9
Percentage depletion in excess of cost	(1.2)	(5.9)
Accounting for uncertain tax positions adjustment	—	1.9
Noncontrolling interest [(b)]	(3.1)	(25.1)
Tax credits [(c)]	(3.6)	—
Effective tax rate adjustment [(d)]	4.4	1.7
Flow-through adjustments [(e)]	(2.6)	(10.6)
AFUDC equity [(f)]	(0.6)	(5.8)
Other tax differences	0.9	0.5
	29.1 %	8.6 %

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(a) In the three months ending June 30, 2017, the state income tax benefit is primarily attributable to favorable flow-through adjustments and a pretax net loss at state tax accruing companies.

(b) The adjustment reflects the noncontrolling interest attributable to the sale of 49.9% of the membership interests of Colorado IPP in April 2016.

(c) The increase in tax credits is due to Peak View Wind Project production tax credits and the marginal gas well tax credit on the oil and gas segment.

(d) Adjustment to reflect the projected annual effective tax rate, pursuant to ASC 740-270.

(e) In the three months ending June 30, 2016, the increase in flow-through was primarily attributable to the Section 263A change of accounting method 481(a) adjustment. This change resulted in a basis difference whose tax benefit is flowed through versus being normalized as federal tax depreciation.

(f) In the three months ending June 30, 2016, AFUDC equity benefit increased primarily due to the Peak View Wind Project.

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

	Six Months Ended June 30,	
Tax (benefit) expense	2017	2016
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect) [(a)]	1.0	3.8
Percentage depletion in excess of cost [(b)]	(0.6)	(13.5)
Accounting for uncertain tax positions adjustment [(c)]	—	(10.4)
Noncontrolling interest [(d)]	(1.6)	(1.9)
IRC 172(f) carryback claim [(e)]	(1.3)	—
Tax credits [(f)]	(1.8)	—
Effective tax rate adjustment [(g)]	(0.8)	(3.5)
Flow-through adjustments [(h)]	(1.0)	(1.7)
Transaction costs	—	2.3
Other tax differences	0.4	(0.6)
	29.3 %	9.5 %

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

(b) The tax benefit for the six months ended June 30, 2016 relates to additional percentage depletion deductions that are being claimed with respect to the oil and gas properties involving prior tax years. Such deductions are primarily the result of a change in the application of the maximum daily limitation of 1,000 barrels of oil equivalent as allowed under the Internal Revenue Code.

(c) The tax benefit for the six months ended June 30, 2016 relates to the release of after-tax interest expense that was previously accrued with respect to the liability for uncertain tax positions involving the like-kind exchange transaction effectuated in connection with the IPP Transaction and Aquila Transaction that occurred in 2008. In addition, the tax benefit includes the release of reserves involving research and development credits and deductions. Both adjustments are the result of a re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016.

(d) Black Hills Colorado IPP went from a single member LLC, wholly-owned by Black Hills Electric Generation, to a partnership as a result of the sale of 49.9% of its membership interest in April 2016. The effective tax rate reflects the income attributable to the noncontrolling interest for which a tax provision is not recorded.

(e) In Q1 2017, the Company filed amended income tax returns for the years 2006 through 2008 to carryback specified liability losses in accordance with IRC172(f). As a result of filing the amended returns, the Company's accrued tax liability interest decreased, certain valuation allowances increased and the previously recorded domestic production activities deduction decreased.

(f) The tax credits for the six months ended June 30, 2017 are the result of Colorado Electric placing the Peak View Wind Project into service in November 2016. The Peak View Wind Project began generating production tax credits during the fourth quarter of 2016.

(g) Adjustment to reflect our 2017 and 2016 annual projected effective tax rate, pursuant to ASC 740-270.

(h) The flow-through adjustments related primarily to an accounting method change for tax purpose that allows us to take a current tax deduction for repair costs that continue to be capitalized for book purposes. In addition, flow-through adjustments were recorded related to an accounting method change for tax purposes that allows us to take a current tax deduction for certain indirect costs that continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to tax expense. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record tax benefits consistent with the flow-through method.

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

(19) ACCRUED LIABILITIES

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

	June 30, 2017	December 31, 2016	June 30, 2016
Accrued employee compensation, benefits and withholdings	$45,767	$56,926	$45,991
Accrued property taxes	34,683	40,004	33,295
Customer deposits and prepayments	41,067	51,628	44,200
Accrued interest and contract adjustment payments	33,914	45,503	42,330
CIAC current portion	1,575	—	20,211
Other (none of which is individually significant)	44,987	49,973	32,223
Total accrued liabilities	$201,993	$244,034	$218,250

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

We are a customer-focused, growth-oriented utility company operating in the United States. We report our operations and results in the following financial segments:

Electric Utilities: Our Electric Utilities segment generates, transmits and distributes electricity to approximately 208,500 customers in South Dakota, Wyoming, Colorado and Montana. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates.

Gas Utilities: Our Gas Utilities conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming subsidiaries. Our Gas Utilities distribute and transport natural gas through our pipeline network to approximately 1,030,800 natural gas customers. Additionally, we sell temporarily-available, contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates.

We also provide non-regulated services through Black Hills Energy Services. Black Hills Energy Services provides approximately 55,000 retail distribution customers in Nebraska and Wyoming with unbundled natural gas commodity offerings under the regulatory-approved Choice Gas Program. We also sell, install and service air, heating and water-heating equipment, and provide associated repair service and protection plans under various trade names. Service Guard and CAPP primarily provide appliance repair services to approximately 61,000 and 33,000 residential customers, respectively, through Company technicians and third-party service providers, typically through on-going monthly service agreements. Tech Services primarily serves gas transportation customers throughout our service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.

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

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

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

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for our electric utilities is June through August while the normal peak usage season for our gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2017 and 2016, and our financial condition as of June 30, 2017, December 31, 2016 and June 30, 2016, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period or for the entire year.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 73.

The segment information does not include inter-company eliminations. Minor differences in amounts may result due to rounding. All amounts are presented on a pre-tax basis unless otherwise indicated.

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. Net income (loss) available for common stock for the three months ended June 30, 2017 was $22 million, or $0.40 per share, compared to Net income (loss) available for common stock of $0.7 million, or $0.01 per share, reported for the same period in 2016. The Net income (loss) available for common stock for the three months ended June 30, 2017 increased over the same period in the prior year primarily due to a decrease in after-tax impairment charges of approximately $16 million on our oil and gas properties, lower after-tax corporate expenses of approximately $4.1 million primarily due to acquisition and transition costs incurred in the prior year, and higher earnings of $2.0 million at our Mining segment resulting from an increase in tons sold driven by a prior year outage. These are partially offset by lower earnings of $1.3 million at our Gas Utilities.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. Net income (loss) available for common stock for the six months ended June 30, 2017 was $99 million, or $1.79 per share, compared to Net income (loss) available for common stock of $41 million, or $0.78 per share, reported for the same period in 2016. The Net income (loss) available for common stock for the six months ended June 30, 2017 increased over the same period in the prior year primarily due to higher earnings at our Gas Utilities, Electric Utilities and Mining segments, lower corporate expenses, and a decrease in impairment charges on our oil and gas properties, partially offset by lower earnings at our Power Generation segment and by tax benefits realized during the same period in the prior year.

Net income (loss) available for common stock for the six months ended June 30, 2017 included a $13 million increase in our Gas Utilities’ earnings with a full six months of earnings from our acquired SourceGas utilities compared to approximately 4.5 months in the same period of the prior year. Corporate expenses decreased by a total of $22 million after-tax compared to the same period in the prior year driven primarily by a $19 million after-tax reduction of acquisition and transition costs. Our Electric Utilities’ earnings increased approximately $2.6 million driven primarily by returns on prior year generation investments. Earnings at our Mining segment increased $1.9 million due to an increase in tons sold as a result of an extended outage in the prior year. The Net income (loss) available for common stock for the six months ended June 30, 2017 is net of $6.7 million of net income attributable to noncontrolling interests compared to $2.7 million in the same period of the prior year. We recognized a $1.4 million tax benefit from a carryback claim during the six months ended June 30, 2017 compared to the same period in the prior year. The prior year included approximately $11 million in tax benefits recognized from additional percentage depletion deductions claimed with respect to our oil and gas properties and the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016. The six months ended June 30, 2016 also included non-cash after-tax impairments on our oil and gas properties of $25 million.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	Variance	2017	2016	Variance
Revenue						
Revenue	$377,790	$353,849	$23,941	$965,312	$839,563	$125,749
Inter-company eliminations	(29,812)	(28,408)	(1,404)	(63,331)	(64,163)	832
	$347,978	$325,441	$22,537	$901,981	$775,400	$126,581
Net income (loss) available for common stock						
Electric Utilities	$18,832	$19,229	$(397)	$41,062	$38,444	$2,618
Gas Utilities	(272)	987	(1,259)	45,738	32,914	12,824
Power Generation [a]	5,332	5,683	(351)	11,862	14,265	(2,403)
Mining	2,681	724	1,957	5,571	3,662	1,909
Oil and Gas [b] [c]	(1,946)	(19,424)	17,478	(4,897)	(26,448)	21,551
	24,627	7,199	17,428	99,336	62,837	36,499
Corporate activities and eliminations [d] [e]	(2,432)	(6,530)	4,098	(618)	(22,166)	21,548
Net income (loss) available for common stock	$22,195	$669	$21,526	$98,718	$40,671	$58,047

(a) Net income (loss) available for common stock for the three and six months ended June 30, 2017 is net of net income attributable to noncontrolling interest of $3.1 million and $6.6 million, respectively, and $2.6 million for both the three and six months ended June 30, 2016.

(b) Net income (loss) available for common stock for the three and six months ended June 30, 2016 included non-cash after-tax impairments of our oil and gas properties of $16 million and $25 million. See Note 17 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

(d) Net income (loss) available for common stock for the three and six months ended June 30, 2017 included incremental, non-recurring acquisition costs, after-tax of $0.3 million and $1.2 million, respectively, as compared to $4.1 million and $20 million for the same periods in the prior year. The three and six months ended June 30, 2016 also included after-tax internal labor costs attributable to the acquisition of $2.0 million and $5.7 million, respectively.

(e) Net income (loss) available for common stock for the six months ended June 30, 2017 included a net tax benefit of approximately $1.4 million from a carryback claim for specified liability losses involving prior tax years. Net income (loss) available for common stock for the six months ended June 30, 2016 included tax benefits of approximately $4.4 million as a result of the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016. See Note 18 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Overview of Business Segments and Corporate Activity

Electric Utilities Segment

- Electric Utilities experienced milder weather during the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016. Cooling degree days for the three and six months ended June 30, 2017 were 14% higher than normal compared to 68% higher than normal for the same periods in 2016. Compared to the same periods in the prior year, cooling degree days were 38% lower. Heating degree days for the three and six months ended June 30, 2017 were 9% and 11% lower than normal, respectively, compared to 14% and 13% lower than normal for the same periods in 2016.

- On January 17, 2017, Colorado Electric received approval from the CPUC for a settlement agreement of its electric resource plan which provides for the addition of 60 megawatts of renewable energy to be in service by 2019. The resource plan was filed June 3, 2016, to meet requirements under the Colorado Renewable Energy Standard. In the second quarter of 2017, Colorado Electric issued a request for proposals to construct new generation and plans to present the results to the CPUC by year-end.

- On January 9, 2017, we filed an application with the CPUC for rehearing, reargument or reconsideration of the Commission's December 19, 2016 decision to increase annual revenue by $1.2 million. This application was denied by the CPUC on June 9, 2017. We subsequently filed an appeal of this decision with Denver District Court on July 10, 2017.

- Construction was completed on the 144 mile-long transmission line connecting the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange was placed in service on May 30, 2017.

- On July 19, 2017, Wyoming Electric set a new summer load peak of 249 MW, exceeding the previous summer peak of 236 MW set in July 2016.

Gas Utilities Segment

- Gas Utilities experienced slightly colder weather during the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016. Heating degree days for the three and six months ended June 30, 2017 were 9% and 12% lower than normal, respectively, compared to 17% and 20% lower than normal for the same periods in 2016.

Oil and Gas Segment

- Oil and Gas production volumes decreased 23% and 22% for the three and six months ended June 30, 2017 compared to the same periods in 2016, respectively. The decrease in production was due to the 2016 sales of non-core properties, and limiting natural gas production to meet minimum daily quantity contractual gas processing commitments in the Piceance. Crude oil production also decreased due to non-core property sales in the fourth quarter of 2016. The average hedged price received for natural gas increased 68% and 48% for the three and six months ended June 30, 2017 compared to the same periods in 2016, respectively. The average hedged price received for oil decreased 25% and 15% for the three and six months ended June 30, 2017 compared to the same periods in 2016, respectively.

Corporate Activities

- We utilized favorable short-term borrowings from our CP program to pay down $100 million on a Corporate term loan due in 2019 with principal payments of $50 million paid in May and an additional $50 million paid in July.

- On July 21, 2017, S&P affirmed Black Hills' credit rating at BBB rating and maintained a Stable outlook.

- On March 29, 2017, Fitch affirmed Black Hills' credit rating at BBB+ rating and changed its outlook from Negative to Stable, citing successful integration of SourceGas, a low business risk profile focused on utility operations and expected improvement of credit metrics.

Operating Results

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

Non-GAAP Financial Measure

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

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

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

Electric Utilities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	Variance	2017	2016	Variance
	(in thousands)					
Revenue	$168,453	$161,481	$6,972	$344,477	$328,757	$15,720
Total fuel and purchased power	62,265	61,418	847	130,665	127,524	3,141
Gross margin	106,188	100,063	6,125	213,812	201,233	12,579
Operations and maintenance	44,315	38,879	5,436	85,098	78,204	6,894
Depreciation and amortization	23,120	20,473	2,647	45,981	41,731	4,250
Total operating expenses	67,435	59,352	8,083	131,079	119,935	11,144
Operating income	38,753	40,711	(1,958)	82,733	81,298	1,435
Interest expense, net	(12,893)	(12,131)	(762)	(26,305)	(24,630)	(1,675)
Other income (expense), net	590	838	(248)	930	1,493	(563)
Income tax benefit (expense)	(7,618)	(10,189)	2,571	(16,296)	(19,717)	3,421
Net income	$18,832	$19,229	$(397)	$41,062	$38,444	$2,618

Results of Operations for the Electric Utilities for the Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016: Net income available for common stock for the Electric Utilities was $19 million for the three months ended June 30, 2017, compared to Net income available for common stock of $19 million for the three months ended June 30, 2016, as a result of:

Gross margin increased due to a $2.3 million return on investment from the Peak View Wind Project, a $1.9 million increase in commercial and industrial margins driven by increased demand largely associated with data centers in Cheyenne, Wyoming, a $1.6 million increase due to prior year billing true-ups, and a $1.5 million increase in rider revenues primarily related to transmission investment recovery. Partially offsetting these increases was $1.2 million in lower residential margins driven primarily by lower cooling degree days as compared to prior year. Cooling degree days were 14 percent higher than normal in the current year as compared to 68 percent higher than normal for the same period in the prior year.

Operations and maintenance increased primarily due to $1.7 million of higher employee costs as a result of prior year integration activities and transition expenses charged to the Corporate segment. Generation outage-related expenses increased by $1.3 million due to the timing of current year outages compared to the prior year and operating expenses increased $0.5 million from the addition of the Peak View Wind Project and the 40-megawatt gas turbine at the Pueblo Airport Generating Station. Property taxes associated with increased asset base increased $0.7 million. A variety of smaller items contributed to the remainder of the increase.

Depreciation and amortization increased primarily due to a higher asset base driven by the addition of the Peak View Wind Project and the 40-megawatt gas turbine at the Pueblo Airport Generating Station.

Interest expense, net increased primarily due to higher intercompany debt resulting from additional investments as compared to prior year.

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

Income tax benefit (expense): The effective tax rate was lower than the prior year due primarily to wind production tax credits related to the Peak View Wind Project.

Results of Operations for the Electric Utilities for the Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016: Net income available for common stock for the Electric Utilities was $41 million for the six months ended June 30, 2017, compared to Net income available for common stock of $38 million for the six months ended June 30, 2016, as a result of:

Gross margin increased over the prior year reflecting a $4.5 million return on investment from the Peak View Wind Project, a $3.7 million increase in commercial and industrial margins driven by increased demand largely associated with data centers in Cheyenne, Wyoming, a $2.9 million increase in rider revenues primarily related to transmission investment recovery, and a $1.5 million increase due to a prior year billing true-up.

Operations and maintenance increased primarily due to $4.6 million of higher employee costs as a result of prior year integration activities and transition expenses charged to the Corporate segment, $1.4 million of higher property taxes with increased asset base, and $1.0 million of higher operating expenses from the Peak View Wind Project and Pueblo Airport Generating Station gas turbine additions.

Depreciation and amortization increased primarily due to a higher asset base driven by the addition of the Peak View Wind Project and the 40-megawatt gas turbine at the Pueblo Airport Generating Station.

Interest expense, net increased primarily due to higher intercompany debt resulting from additional investments as compared to prior year.

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

Income tax benefit (expense): The effective tax rate was lower than the prior year due primarily to wind production tax credits related to the Peak View Wind Project.

Revenue - Electric (in thousands)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Residential:				
South Dakota Electric	$15,633	$16,241	$35,704	$35,556
Wyoming Electric	9,077	9,241	19,488	19,698
Colorado Electric	23,223	23,148	46,959	46,261
Total Residential	47,933	48,630	102,151	101,515
Commercial:				
South Dakota Electric	22,858	23,723	47,149	47,312
Wyoming Electric	16,205	15,839	32,176	31,512
Colorado Electric	24,875	24,392	48,126	46,875
Total Commercial	63,938	63,954	127,451	125,699
Industrial:				
South Dakota Electric	8,171	7,764	16,625	16,265
Wyoming Electric	12,831	10,352	25,633	20,449
Colorado Electric	9,734	9,782	18,761	19,047
Total Industrial	30,736	27,898	61,019	55,761
Municipal:				
South Dakota Electric	942	960	1,778	1,791
Wyoming Electric	543	552	1,046	1,063
Colorado Electric	3,191	2,885	6,152	5,580
Total Municipal	4,676	4,397	8,976	8,434
Total Retail Revenue - Electric	147,283	144,879	299,597	291,409
Contract Wholesale:				
Total Contract Wholesale - South Dakota Electric [(a)]	6,702	3,947	14,545	8,121
Off-system Wholesale:				
South Dakota Electric	2,424	2,734	6,257	7,320
Wyoming Electric	1,081	1,007	2,747	2,853
Colorado Electric	163	573	174	707
Total Off-system Wholesale	3,668	4,314	9,178	10,880
Other Revenue:				
South Dakota Electric	9,322	6,650	17,788	14,296
Wyoming Electric	614	520	1,539	1,110
Colorado Electric	864	1,171	1,830	2,941
Total Other Revenue	10,800	8,341	21,157	18,347
Total Revenue - Electric	$168,453	$161,481	$344,477	$328,757

(a) Increase for the three and six months ended June 30, 2017 was primarily due to a new 50 MW power sales agreement with Cargill effective January 1, 2017.

	Three Months Ended June 30,		Six Months Ended June 30,	
Quantities Generated and Purchased (in MWh)	2017	2016	2017	2016
Generated —				
Coal-fired:				
South Dakota Electric	289,540	265,032	677,525	653,033
Wyoming Electric	176,725	180,081	360,820	359,774
Total Coal-fired	466,265	445,113	1,038,345	1,012,807
Natural Gas and Oil:				
South Dakota Electric (a)	11,024	39,433	21,374	54,995
Wyoming Electric (a)	7,292	27,191	13,569	35,070
Colorado Electric	45,755	61,123	57,657	63,890
Total Natural Gas and Oil	64,071	127,747	92,600	153,955
Wind:				
Colorado Electric (b)	58,113	10,588	128,656	23,649
Total Wind	58,113	10,588	128,656	23,649
Total Generated:				
South Dakota Electric	300,564	304,465	698,899	708,028
Wyoming Electric (a)	184,017	207,272	374,389	394,844
Colorado Electric (b)	103,868	71,711	186,313	87,539
Total Generated	588,449	583,448	1,259,601	1,190,411
Purchased —				
South Dakota Electric (c)	418,314	315,379	865,811	655,069
Wyoming Electric (d)	239,140	186,085	488,675	408,880
Colorado Electric (b)	394,614	467,365	797,041	945,248
Total Purchased	1,052,068	968,829	2,151,527	2,009,197
Total Generated and Purchased:				
South Dakota Electric (c)	718,878	619,844	1,564,710	1,363,097
Wyoming Electric	423,157	393,357	863,064	803,724
Colorado Electric	498,482	539,076	983,354	1,032,787
Total Generated and Purchased	1,640,517	1,552,277	3,411,128	3,199,608

(a) Decrease is primarily due to the ability to purchase excess generation in the open market at a lower cost than to generate for the three and six months ended June 30, 2017.

(b) Increase in 2017 is due to the addition of the Peak View Wind Project in November 2016. This generation replaced resources provided by PPAs in 2016.

(c) Increase in 2017 is primarily driven by resource needs from a new 50MW power sales agreement with Cargill effective January 1, 2017.

(d) Year over year increases are primarily driven by new load supporting data centers in Cheyenne, Wyoming.

Quantity Sold (in MWh)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Residential:				
South Dakota Electric	107,521	114,851	257,093	257,604
Wyoming Electric	57,191	59,587	124,364	127,900
Colorado Electric	142,154	144,318	287,514	293,346
Total Residential	306,866	318,756	668,971	678,850
Commercial:				
South Dakota Electric	173,720	190,207	370,126	379,095
Wyoming Electric	128,827	130,550	261,009	260,880
Colorado Electric	182,658	184,150	358,144	360,346
Total Commercial	485,205	504,907	989,279	1,000,321
Industrial:				
South Dakota Electric	103,497	102,620	213,293	210,641
Wyoming Electric [(a)]	184,809	150,332	362,796	293,074
Colorado Electric	106,490	113,454	209,281	212,943
Total Industrial	394,796	366,406	785,370	716,658
Municipal:				
South Dakota Electric	8,104	8,487	15,709	15,928
Wyoming Electric	2,006	2,102	4,489	4,647
Colorado Electric	30,594	30,026	57,478	56,609
Total Municipal	40,704	40,615	77,676	77,184
Total Retail Quantity Sold	1,227,571	1,230,684	2,521,296	2,473,013
Contract Wholesale:				
Total Contract Wholesale-South Dakota Electric [(b)]	165,881	56,087	351,997	119,540
Off-system Wholesale:				
South Dakota Electric [(c)]	102,966	117,064	257,462	310,437
Wyoming Electric	22,183	21,253	54,536	58,746
Colorado Electric [(c)]	5,274	28,233	5,860	35,695
Total Off-system Wholesale	130,423	166,550	317,858	404,878
Total Quantity Sold:				
South Dakota Electric	661,689	589,316	1,465,680	1,293,245
Wyoming Electric	395,016	363,824	807,194	745,247
Colorado Electric	467,170	500,181	918,277	958,939
Total Quantity Sold	1,523,875	1,453,321	3,191,151	2,997,431
Other Uses, Losses or Generation, net [(d)]:				
South Dakota Electric	57,189	30,528	99,030	69,852
Wyoming Electric	28,141	29,533	55,870	58,477
Colorado Electric	31,312	38,895	65,077	73,848

Total Other Uses, Losses and Generation, net	116,642	98,956	219,977	202,177
Total Energy	1,640,517	1,552,277	3,411,128	3,199,608

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(a) Year over year increases are driven by new load supporting data centers in Cheyenne, Wyoming.

(b) Increase for the three and six months ended June 30, 2017 was primarily due to a new 50 MW power sales agreement with Cargill effective January 1, 2017.

(c) Decrease in 2017 generation was primarily driven by commodity prices that impacted power marketing sales.

(d) Includes company uses, line losses, and excess exchange production.

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Degree Days	Three Months Ended June 30, 2017			2016	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Heating Degree Days:					
South Dakota Electric	910	(11)%	4%	877	(13)%
Wyoming Electric	1,164	(5)%	3%	1,134	(15)%
Colorado Electric	567	(10)%	10%	516	(15)%
Combined [(a)]	804	(9)%	6%	762	(14)%
Cooling Degree Days:					
South Dakota Electric	114	15 %	(39)%	186	74 %
Wyoming Electric	41	(18)%	(60)%	102	100 %
Colorado Electric	243	16 %	(34)%	369	63 %
Combined [(a)]	158	14 %	(38)%	253	68 %

Degree Days	Six Months Ended June 30, 2017			2016	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Heating Degree Days:					
South Dakota Electric	4,040	(5)%	10%	3,683	(13)%
Wyoming Electric	3,894	(12)%	—%	3,910	(12)%
Colorado Electric	2,686	(17)%	(4)%	2,801	(13)%
Combined [(a)]	3,391	(11)%	2%	3,323	(13)%
Cooling Degree Days:					
South Dakota Electric	114	15 %	(39)%	186	74 %
Wyoming Electric	41	(18)%	(60)%	102	100 %
Colorado Electric	243	16 %	(34)%	369	63 %
Combined [(a)]	158	14 %	(38)%	253	68 %

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

Electric Utilities Power Plant Availability	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Coal-fired plants [(a)]	74.8%	75.1%	83.0%	84.5%
Natural gas fired plants and Other plants	94.5%	97.6%	96.5%	96.2%
Wind [(b)]	93.4%	99.3%	92.4%	99.3%
Total availability	88.0%	89.5%	91.8%	92.0%

Wind capacity factor	35.8%	33.6%	39.7%	37.5%

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(a) Both years included outages. 2017 included planned outages at Neil Simpson II, Wyodak and Wygen II, and 2016 included a planned outage at Wygen III and an extended planned outage at Wyodak.

(b) 2017 is lower than the prior year primarily due to the addition of the Peak View Wind Project for which 2017 is the first year of commercial operation.

Gas Utilities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	Variance	2017	2016	Variance
	(in thousands)					
Revenue:						
Natural gas — regulated	$150,426	$137,840	$12,586	$492,059	$392,264	$99,795
Other — non-regulated services	16,021	14,121	1,900	39,298	30,170	9,128
Total revenue	166,447	151,961	14,486	531,357	422,434	108,923
Cost of sales						
Natural gas — regulated	52,332	43,149	9,183	222,034	172,914	49,120
Other — non-regulated services	10,018	5,156	4,862	21,698	13,355	8,343
Total cost of sales	62,350	48,305	14,045	243,732	186,269	57,463
Gross margin	104,097	103,656	441	287,625	236,165	51,460
Operations and maintenance	64,956	62,237	2,719	135,715	114,924	20,791
Depreciation and amortization	20,924	19,931	993	41,721	35,903	5,818
Total operating expenses	85,880	82,168	3,712	177,436	150,827	26,609
Operating income (loss)	18,217	21,488	(3,271)	110,189	85,338	24,851
Interest expense, net	(19,610)	(19,074)	(536)	(39,392)	(32,591)	(6,801)
Other income (expense), net	(225)	(261)	36	(48)	390	(438)
Income tax benefit (expense)	1,346	(1,184)	2,530	(24,904)	(20,193)	(4,711)
Net income (loss)	(272)	969	(1,241)	45,845	32,944	12,901
Net (income) loss attributable to noncontrolling interest	—	18	(18)	(107)	(30)	(77)
Net income (loss) available for common stock	$(272)	$987	$(1,259)	$45,738	$32,914	$12,824

Results of Operations for the Gas Utilities for the Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016: Net loss available for common stock for the Gas Utilities was $(0.3) million for the three months ended June 30, 2017, compared to Net income available for common stock of $1.0 million for the three months ended June 30, 2016, as a result of:

Gross margin was comparable to the same period in the prior year with comparable heating degree days in an off-peak quarter.

Operations and maintenance increased primarily due to $2.3 million higher employee related expenses as a result of prior year integration activities and transition expenses charged to the Corporate segment.

Depreciation and amortization increased due to additional depreciation from the higher asset base.

Interest expense, net increased primarily due to refinancing from variable to fixed rate debt, partially off-set by reduced borrowings.

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

Income tax benefit (expense): The effective tax rate is different due to pretax loss in 2017 and pretax income in 2016.

Results of Operations for the Gas Utilities for the Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016: Net income available for common stock for the Gas Utilities was $46 million for the six months ended June 30, 2017, compared to Net income available for common stock of $33 million for the six months ended June 30, 2016, as a result of:

Gross margin increased primarily due to margins of approximately $51 million contributed by the SourceGas utilities reflecting a full six months of results in 2017 as compared to approximately 4.5 months in 2016.

Operations and maintenance increased primarily due to additional operating costs of approximately $19 million for the acquired SourceGas utilities, reflecting a full six months of results in 2017 as compared to approximately 4.5 months in 2016. This $19 million increase included approximately $2.9 million of prior year integration activities and transition expenses charged to the Corporate segment. In addition, employee related expenses increased by $2.9 million for the Black Hills legacy gas utilities as a result of prior year integration activities and transition expenses charged to the Corporate segment.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas utilities.

Interest expense, net increased primarily due to additional interest expense from the acquired SourceGas utilities.

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

Income tax benefit (expense): The effective tax rate was lower as compared to the same period in the prior year primarily due to greater flow through benefit.

Revenue (in thousands) [(a)]	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Residential:				
Arkansas	$12,551	$9,799	$48,907	$25,577
Colorado	20,659	21,361	67,440	53,141
Nebraska [(b)]	15,841	14,327	60,343	56,873
Iowa	13,991	12,787	50,304	47,634
Kansas	10,097	9,320	36,181	31,668
Wyoming [(b)]	8,112	7,652	23,428	18,768
Total Residential	$81,251	$75,246	$286,603	$233,661
Commercial:				
Arkansas	$7,131	$4,801	$25,184	$12,529
Colorado	8,127	7,939	25,074	18,136
Nebraska	3,671	3,256	17,573	16,339
Iowa	5,133	4,336	21,097	19,473
Kansas	3,107	2,090	12,023	10,260
Wyoming	3,885	3,477	11,839	9,180
Total Commercial	$31,054	$25,899	$112,790	$85,917
Industrial:				
Arkansas	$1,361	$771	$3,581	$1,608
Colorado	313	278	682	532
Nebraska	55	69	205	187
Iowa	228	250	1,039	825
Kansas	1,585	1,959	1,982	2,589
Wyoming	739	703	1,738	1,657
Total Industrial	$4,281	$4,030	$9,227	$7,398
Transportation:				
Arkansas	$2,415	$2,110	$5,415	$3,733
Colorado	819	860	2,202	1,765
Nebraska [(b)]	15,219	14,148	33,859	25,925
Iowa	1,119	1,080	2,590	2,555
Kansas	1,311	1,355	3,253	3,398
Wyoming [(b)]	5,431	5,505	14,462	10,137
Total Transportation	$26,314	$25,058	$61,781	$47,513

	Three Months Ended June 30,		Six Months Ended June 30,	
Revenue (in thousands) (continued)	2017	2016	2017	2016
Transmission:				
Arkansas	$450	$12	$1,212	$25
Colorado	4,018	3,683	13,764	8,762
Wyoming	1,223	1,118	2,501	2,177
Total Transmission	$5,691	$4,813	$17,477	$10,964
Other Sales Revenue:				
Arkansas	$76	$520	$662	$1,289
Colorado	149	292	479	455
Nebraska	788	874	1,787	1,675
Iowa	152	213	261	313
Kansas	408	643	442	2,633
Wyoming	262	252	550	446
Total Other Sales Revenue	$1,835	$2,794	$4,181	$6,811
Total Regulated Revenue	$150,426	$137,840	$492,059	$392,264
Non-regulated Services	16,021	14,121	39,298	30,170
Total Revenue	$166,447	$151,961	$531,357	$422,434

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(a) Certain prior year revenue classes have been revised to conform to current year presentation; total revenue did not change.

(b) Change in prior year due to reclassification of Residential Choice customers from Residential to Transportation class.

	Three Months Ended June 30,		Six Months Ended June 30,	
Gross Margin (in thousands) [(a)]	2017	2016	2017	2016
Residential:				
Arkansas	$8,642	$7,752	$31,086	$17,381
Colorado	9,419	9,819	26,251	21,296
Nebraska [(b)]	10,313	9,936	29,050	28,420
Iowa	9,221	8,989	23,012	22,596
Kansas	6,557	6,444	17,998	16,529
Wyoming [(b)]	5,041	5,001	12,847	11,301
Total Residential	$49,193	$47,941	$140,244	$117,523
Commercial:				
Arkansas	$3,578	$3,012	$13,149	$7,044
Colorado	3,311	3,072	8,462	6,227
Nebraska	1,798	1,756	6,346	6,213
Iowa	2,203	2,168	6,574	6,457
Kansas	1,464	1,100	4,475	4,011
Wyoming	1,681	1,715	4,828	4,379

Total Commercial	$14,035	$12,823	$43,834	$34,331

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Gross Margin (in thousands) (continued)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Industrial:				
Arkansas	$311	$368	$1,161	$686
Colorado	108	148	221	268
Nebraska	25	50	77	95
Iowa	46	44	136	87
Kansas	379	539	586	768
Wyoming	157	147	327	350
Total Industrial	$1,026	$1,296	$2,508	$2,254
Transportation:				
Arkansas	$2,415	$2,110	$5,415	$3,733
Colorado	819	860	2,202	1,765
Nebraska (b)	15,219	14,148	33,859	25,925
Iowa	1,119	1,080	2,590	2,555
Kansas	1,311	1,355	3,253	3,398
Wyoming (b)	5,431	5,505	14,462	10,137
Total Transportation	$26,314	$25,058	$61,781	$47,513
Transmission:				
Arkansas	$450	$12	$1,212	$25
Colorado	4,018	3,613	13,764	8,751
Wyoming	1,223	1,154	2,501	2,153
Total Transmission	$5,691	$4,779	$17,477	$10,929
Other Sales Margins:				
Arkansas	$76	$521	$662	$1,290
Colorado	149	292	479	455
Nebraska	788	873	1,787	1,674
Iowa	152	213	261	313
Kansas	408	643	442	2,622
Wyoming	262	252	550	446
Total Other Sales Margins	$1,835	$2,794	$4,181	$6,800
Total Regulated Gross Margin	$98,094	$94,691	$270,025	$219,350
Non-regulated Services	6,003	8,965	17,600	16,815
Total Gross Margin	$104,097	$103,656	$287,625	$236,165

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(a) Certain prior year revenue classes have been revised to conform to current year presentation.

(b) Change in prior year due to reclassification of Residential Choice customers from Residential to Transportation class.

Gas Utilities Quantities Sold and Transportation (in Dth) [(a)]	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Residential:				
Arkansas	964,399	852,523	4,528,144	2,745,603
Colorado	2,233,388	2,528,067	8,270,827	6,945,901
Nebraska [(b)]	1,220,650	1,171,552	6,749,118	6,656,046
Iowa	1,116,176	1,227,179	6,146,579	6,265,928
Kansas	706,934	736,678	3,634,937	3,654,752
Wyoming [(b)]	859,789	908,572	3,039,865	2,615,807
Total Residential	7,101,336	7,424,571	32,369,470	28,884,037
Commercial:				
Arkansas	871,222	696,526		