BLACK HILLS CORP /SD/
Form 10-Q
November 04, 2014

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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2014

OR

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

Commission File Number 001-31303

Black Hills Corporation
Incorporated in South Dakota IRS Identification Number 46-0458824
625 Ninth Street
Rapid City, South Dakota 57701
Registrant’s telephone number (605) 721-1700

Former name, former address, and former fiscal year if changed since last report
NONE

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

Yes x No o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes x No o

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

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

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

Yes o No x

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

Class	Outstanding at October 31, 2014	
Common stock, $1.00 par value	44,655,369	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)
ASU	Accounting Standards Update issued by the FASB
Bbl	Barrel
BHC	Black Hills Corporation; the Company
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business of Black Hills Utility Holdings, Inc., and its subsidiaries
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
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation
Cheyenne Prairie	Cheyenne Prairie Generating Station is a 132 MW natural gas-fired generating facility jointly owned by Black Hills Power and Cheyenne Light in Cheyenne, Wyoming. Cheyenne Prairie was placed into commercial service on October 1, 2014.
Colorado Electric	Black Hills Colorado Electric Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado IPP	Black Hills Colorado IPP, LLC a direct wholly-owned subsidiary of Black Hills Electric Generation
Cooling degree day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
CT	Combustion turbine
CVA	Credit Valuation Adjustment
De-designated interest rate swaps	The $250 million notional amount interest rate swaps that were originally designated as cash flow hedges under accounting for derivatives and hedges but subsequently de-designated in December 2008. These swaps were settled in November 2013.
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)

EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America

Heating Degree Day	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
IPP	Independent power producer
IRS	United States Internal Revenue Service
IUB	Iowa Utilities Board
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
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.
MW	Megawatts
MWh	Megawatt-hours
NGL	Natural Gas Liquids (7 Gallons equals 1 Mcfe)
NOAA	National Oceanic and Atmospheric Administration
NOAA Climate Normals	This dataset is produced once every 10 years. This dataset contains daily and monthly normals of temperature, precipitation, snowfall, heating and cooling degree days, frost/freeze dates, and growing degree days calculated from observations at approximately 9,800 stations operated by NOAA’s National Weather Service.
NOL	Net Operating Loss
OTC	Over-the-counter
PCA	Purchased Cost Adjustment - Adjustments passed through to the customer based on purchased fuel costs that are higher or lower than costs approved in the rate case.
PPA	Power Purchase Agreement
Revolving Credit Facility	Our $500 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2019.
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
S&P	Standard and Poor’s, a division of The McGraw-Hill Companies, Inc.
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.
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands, except per share amounts)			
Revenue	$272,087	$259,907	$1,015,493	$920,404
Operating expenses:				
Utilities -				
Fuel, purchased power and cost of natural gas sold	84,674	71,503	416,473	338,848
Operations and maintenance	64,245	66,061	201,546	196,728
Non-regulated energy operations and maintenance	20,170	20,484	63,852	62,703
Depreciation, depletion and amortization	37,463	36,135	110,258	106,068
Taxes - property, production and severance	11,082	10,068	32,462	30,517
Other operating expenses	49	90	323	1,091
Total operating expenses	217,683	204,341	824,914	735,955
Operating income	54,404	55,566	190,579	184,449
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(17,919)	(23,840)	(53,665)	(70,881)
Allowance for funds used during construction - borrowed	319	347	845	831
Capitalized interest	231	273	734	811
Unrealized gain (loss) on interest rate swaps, net	—	3,144	—	29,393
Interest income	575	565	1,541	1,325
Allowance for funds used during construction - equity	297	85	828	327
Other income (expense), net	261	318	1,262	1,197
Total other income (expense), net	(16,236)	(19,108)	(48,455)	(36,997)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	38,168	36,458	142,124	147,452
Equity in earnings (loss) of unconsolidated subsidiaries	—	—	(1)	(86)
Income tax benefit (expense)	(11,332)	(13,334)	(47,349)	(50,527)
Net income (loss) available for common stock	$26,836	$23,124	$94,774	$96,839
Earnings (loss) per share of common stock:				
Earnings (loss) per share, Basic -				
Total income (loss) per share, Basic	$0.60	$0.52	$2.14	$2.19
Earnings (loss) per share, Diluted -				
Total income (loss) per share, Diluted	$0.60	$0.52	$2.13	$2.18
Weighted average common shares outstanding:				
Basic	44,415	44,201	44,382	44,143

Diluted	44,608	44,457	44,584	44,395
Dividends declared per share of common stock	$0.39	$0.38	$1.17	$1.14

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

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

(unaudited)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Net income (loss) available for common stock	$26,836	$23,124	$94,774	$96,839
Other comprehensive income (loss), net of tax:				
Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of $(1,840) and $964 for the three months ended 2014 and 2013 and $582 and $(93) for the nine months ended 2014 and 2013, respectively)	3,145	(2,083)	(1,071)	134
Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $(732) and $(586) for the three months ended 2014 and 2013 and $(1,931) and $(1,469) for the nine months ended 2014 and 2013, respectively)	1,328	1,426	3,511	3,095
Benefit plan liability adjustments - net gain (loss) (net of tax of $0 and $0 for the three months ended 2014 and 2013 and $2 and $0 for the nine months ended 2014 and 2013, respectively)	—	—	(2)	—
Benefit plan liability tax adjustments - net gain (loss)	—	—	(394)	—
Benefit plan liability adjustments - prior service cost (net of tax of $0 and $0 for the three months ended 2014 and 2013 and $(90) and $0 for the nine months ended 2014 and 2013, respectively)	—	—	164	—
Reclassification adjustments of benefit plan liability - prior service cost (net of tax of $17 and $22 for the three months ended 2014 and 2013 and $60 and $66 for the nine months ended 2014 and 2013, respectively)	(31)	(41)	(110)	(123)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax of $(86) and $(242) for the three months ended 2014 and 2013 and $(262) and $(729) for the nine months ended 2014 and 2013, respectively)	160	458	485	1,361
Other comprehensive income (loss), net of tax	4,602	(240)	2,583	4,467
Comprehensive income (loss) available for common stock	$31,438	$22,884	$97,357	$101,306

See Note 11 for additional disclosures.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of September 30, 2014 (in thousands)	December 31, 2013	September 30, 2013
ASSETS			
Current assets:			
Cash and cash equivalents	$11,939	$7,841	$13,637
Restricted cash and equivalents	1,918	2	6,782
Accounts receivable, net	123,399	177,573	114,137
Materials, supplies and fuel	105,726	88,478	95,230
Derivative assets, current	—	717	126
Income tax receivable, net	1,268	1,460	4,539
Deferred income tax assets, net, current	34,756	18,889	37,163
Regulatory assets, current	68,444	24,451	30,208
Other current assets	26,502	25,877	27,075
Total current assets	373,952	345,288	328,897
Investments	17,144	16,697	16,612
Property, plant and equipment	4,493,696	4,259,445	4,152,097
Less: accumulated depreciation and depletion	(1,338,509)	(1,269,148)	(1,258,450)
Total property, plant and equipment, net	3,155,187	2,990,297	2,893,647
Other assets:			
Goodwill	353,396	353,396	353,396
Intangible assets, net	3,231	3,397	3,453
Regulatory assets, non-current	140,422	138,197	183,119
Derivative assets, non-current	—	—	—
Other assets, non-current	29,930	27,906	22,116
Total other assets, non-current	526,979	522,896	562,084
TOTAL ASSETS	$4,073,262	$3,875,178	$3,801,240

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Continued)
(unaudited)

	As of September 30, 2014	December 31, 2013	September 30, 2013
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$100,444	$130,416	$77,077
Accrued liabilities	163,374	151,277	152,911
Derivative liabilities, current	3,397	3,474	65,944
Regulatory liabilities, current	828	10,727	14,707
Notes payable	184,000	82,500	138,300
Current maturities of long-term debt	275,000	—	255,694
Total current liabilities	727,043	378,394	704,633
Long-term debt, net of current maturities	1,107,519	1,396,948	955,979
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	506,166	432,287	403,772
Derivative liabilities, non-current	3,273	5,614	11,388
Regulatory liabilities, non-current	118,856	109,429	131,730
Benefit plan liabilities	108,924	111,479	169,448
Other deferred credits and other liabilities	144,089	133,279	133,341
Total deferred credits and other liabilities	881,308	792,088	849,679
Commitments and contingencies (See Notes 7, 8, 13, 14 and 15)			
Stockholders' equity:			
Common stock equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 44,696,670; 44,550,239; and 44,532,245 shares, respectively	44,697	44,550	44,532
Additional paid-in capital	746,575	742,344	740,209
Retained earnings	582,800	540,244	539,030
Treasury stock, at cost – 41,552; 50,877; and 41,127 shares, respectively	(1,841)	(1,968)	(1,801)
Accumulated other comprehensive income (loss)	(14,839)	(17,422)	(31,021)
Total stockholders' equity	1,357,392	1,307,748	1,290,949
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,073,262	$3,875,178	$3,801,240

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Nine Months Ended September 30,	
	2014	2013
Operating activities:	(in thousands)	
Net income (loss) available for common stock	$94,774	$96,839
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	110,258	106,068
Deferred financing cost amortization	1,608	3,209
Derivative fair value adjustments	2,136	275
Stock compensation	6,978	9,100
Unrealized (gain) loss on interest rate swaps, net	—	(29,393)
Deferred income taxes	48,007	54,865
Employee benefit plans	11,109	16,644
Other adjustments, net	2,016	9,434
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	(17,248)	(12,522)
Accounts receivable, unbilled revenues and other operating assets	(61)	28,762
Accounts payable and other operating liabilities	(14,307)	(23,774)
Contributions to defined benefit pension plans	(10,200)	(12,500)
Other operating activities, net	4,087	4,759
Net cash provided by (used in) operating activities	239,157	251,766
Investing activities:		
Property, plant and equipment additions	(290,299)	(239,485)
Proceeds from sale of assets	22,342	—
Other investing activities	(2,364)	2,846
Net cash provided by (used in) investing activities	(270,321)	(236,639)
Financing activities:		
Dividends paid on common stock	(52,218)	(50,678)
Common stock issued	2,393	3,606
Short-term borrowings - issuances	396,250	269,600
Short-term borrowings - repayments	(294,750)	(408,300)
Long-term debt - issuances	—	275,000
Long-term debt - repayments	(12,200)	(106,180)
Other financing activities	(4,213)	—
Net cash provided by (used in) financing activities	35,262	(16,952)
Net change in cash and cash equivalents	4,098	(1,825)
Cash and cash equivalents, beginning of period	7,841	15,462
Cash and cash equivalents, end of period	$11,939	$13,637

See Note 12 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 2013 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 2013 Annual Report on Form 10-K filed with the SEC.

We conduct our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation, Coal Mining and Oil and Gas. Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. All of our operations and assets are located within the United States.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying Condensed Consolidated Financial Statements reflects all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the September 30, 2014, December 31, 2013, and September 30, 2013 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 price. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment’s peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2014 and September 30, 2013, and our financial condition as of September 30, 2014, December 31, 2013, and September 30, 2013, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

Recently Issued and Adopted Accounting Standards

We have implemented all new accounting pronouncements that are in effect and may impact our financial statements and do not believe that there are any other new accounting pronouncements that have been issued that might have a material impact on our financial position, results of operations, or cash flows.

Revenue from Contracts with Customers, ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The standard provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. ASU 2014-09 is effective for annual and interim reporting periods beginning after December 15, 2016 and early adoption is not permitted. We are currently assessing the impact, if any, that ASU 2014-09 will have on our financial position, results of operations or cash flows.

(2) BUSINESS SEGMENT INFORMATION

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

Three Months Ended September 30, 2014	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$171,395	$3,156	$18,154
Gas	78,735	—	1,597
Non-regulated Energy:			
Power Generation	1,602	20,419	7,829
Coal Mining	6,884	8,689	2,638
Oil and Gas	13,471	—	(3,110)
Corporate activities	—	—	(272)
Inter-company eliminations	—	(32,264)	—
Total	$272,087	$—	$26,836

Three Months Ended September 30, 2013	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$169,401	$2,003	$15,097
Gas	67,792	—	(1,450)
Non-regulated Energy:			
Power Generation	1,575	20,393	6,707
Coal Mining	6,713	8,604	2,142
Oil and Gas	14,426	—	(1,682)
Corporate activities [(a)]	—	—	2,310
Inter-company eliminations	—	(31,000)	—
Total	$259,907	$—	$23,124

Nine Months Ended September 30, 2014	External Operating Revenues	Intercompany Operating Revenues	Net Income (Loss)
Utilities:			
Electric	$508,230	$10,307	$44,156
Gas	440,571	—	28,289
Non-regulated Energy:			
Power Generation	4,138	62,211	23,096
Coal Mining	19,085	26,637	7,118
Oil and Gas	43,469	—	(6,792)
Corporate activities	—	—	(1,093)
Inter-company eliminations	—	(99,155)	—
Total	$1,015,493	$—	$94,774

Nine Months Ended September 30, 2013	External Operating Revenues	Intercompany Operating Revenues	Net Income (Loss)
Utilities:			
Electric	$482,222	$9,844	$38,063
Gas	373,440	—	20,225
Non-regulated Energy:			
Power Generation	3,628	58,825	17,382
Coal Mining	19,530	23,688	5,180
Oil and Gas	41,584	—	(3,699)
Corporate activities (a)	—	—	19,688
Inter-company eliminations	—	(92,357)	—
Total	$920,404	$—	$96,839

(a) Corporate activities include a $2.0 million and a $19 million after-tax non-cash mark-to-market gain on certain interest rate swaps for the three and nine months ended September 30, 2013, respectively.

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

Total Assets (net of inter-company eliminations) as of:	September 30, 2014	December 31, 2013	September 30, 2013
Utilities:			
Electric (a)	$2,671,601	$2,525,947	$2,464,123
Gas	827,069	805,617	757,746
Non-regulated Energy:			
Power Generation (a)	64,359	95,692	102,331
Coal Mining	74,130	78,825	82,155
Oil and Gas	330,781	288,366	264,785
Corporate activities	105,322	80,731	130,100
Total assets	$4,073,262	$3,875,178	$3,801,240

(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.

(3) ACCOUNTS RECEIVABLE

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

September 30, 2014	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$53,717	$21,485	$(724)	$74,478
Gas Utilities	23,409	13,218	(740)	35,887
Power Generation	1,368	—	—	1,368
Coal Mining	2,563	—	—	2,563
Oil and Gas	7,657	—	(13)	7,644
Corporate	1,459	—	—	1,459
Total	$90,173	$34,703	$(1,477)	$123,399

December 31, 2013	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$52,437	$23,823	$(666)	$75,594
Gas Utilities	49,162	41,195	(558)	89,799
Power Generation	1,722	—	—	1,722
Coal Mining	1,711	—	—	1,711
Oil and Gas	8,156	—	(13)	8,143
Corporate	604	—	—	604
Total	$113,792	$65,018	$(1,237)	$177,573

September 30, 2013	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$49,254	$20,153	$(648)	$68,759
Gas Utilities	20,693	11,877	(542)	32,028
Power Generation	3	—	—	3
Coal Mining	2,677	—	—	2,677
Oil and Gas	8,463	—	(19)	8,444
Corporate	2,226	—	—	2,226
Total	$83,316	$32,030	$(1,209)	$114,137

(4) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of September 30, 2014	As of December 31, 2013	As of September 30, 2013
Regulatory assets				
Deferred energy and fuel cost adjustments - current [(a)(d)]	1	$26,211	$16,775	$17,925
Deferred gas cost adjustments and natural gas price derivatives [(a)(d)]	7	49,870	12,366	16,845
AFUDC [(b)]	45	12,411	12,315	12,398
Employee benefit plans [(c)]	13	64,908	67,059	114,386
Environmental [(a)]	subject to approval	1,314	1,800	1,800
Asset retirement obligations [(a)]	44	3,282	3,266	3,262
Bond issue cost [(a)]	24	3,311	3,419	3,454
Renewable energy standard adjustment [(a)]	5	12,007	14,186	14,936
Flow through accounting [(c)]	35	25,157	20,916	19,222
Other regulatory assets [(a)]	15	10,395	10,546	9,099
		$208,866	$162,648	$213,327
Regulatory liabilities				
Deferred energy and gas costs [(a)]	1	$5,535	$11,708	$14,032
Employee benefit plans [(c)]	13	34,409	34,431	60,707
Cost of removal [(a)]	44	71,362	64,970	62,069
Other regulatory liabilities [(c)]	25	8,378	9,047	9,629
		$119,684	$120,156	$146,437

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

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

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

(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. Increases in the current year balances as of September 30, 2014 are primarily due to higher natural gas prices driven by demand and market conditions during our peak winter heating season. 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.

(5) MATERIALS, SUPPLIES AND FUEL

The following amounts by major classification are included in Materials, supplies and fuel in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

	September 30, 2014	December 31, 2013	September 30, 2013
Materials and supplies	$52,682	$50,196	$50,564
Fuel - Electric Utilities	7,108	6,213	6,384
Natural gas in storage held for distribution	45,936	32,069	38,282

Total materials, supplies and fuel	$105,726	$88,478	$95,230

(6) EARNINGS PER SHARE

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income (loss) available for common stock	$26,836	$23,124	$94,774	$96,839
Weighted average shares - basic	44,415	44,201	44,382	44,143
Dilutive effect of:				
Equity compensation	193	256	202	252
Weighted average shares - diluted	44,608	44,457	44,584	44,395

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Equity compensation	99	—	75	9
Anti-dilutive shares	99	—	75	9

(7) NOTES PAYABLE AND CURRENT MATURITIES OF LONG-TERM DEBT

We had the following short-term debt outstanding in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

	September 30, 2014		December 31, 2013		September 30, 2013	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$184,000	$31,726	$82,500	$22,100	$138,300	$53,137

Revolving Credit Facility

On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from S&P and Moody’s for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.125%, 1.125%, and 1.125%, respectively, from May 29, 2014 through September 30, 2014; a reduction of 0.25% for each method of borrowing as compared to the previous arrangement. Borrowings under the facility are primarily Eurodollar based. A commitment fee is charged on the unused amount of the Revolving Credit

Facility and was 0.175% based on our credit rating, a reduction of 0.025% compared to the prior arrangement.

Current Maturities of Long-Term Debt

As of September 30, 2014, our $275 million Corporate term loan due June 19, 2015 is classified as Current maturities of long-term debt.

Debt Covenants

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

	As of September 30, 2014	Covenant Requirement
Recourse Leverage Ratio	54%	Less than 65%

As of September 30, 2014, we were in compliance with this covenant.

(8) 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 2013 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; and our fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable-rate debt.

Credit Risk

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

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

We perform ongoing credit evaluations of our customers and adjust credit limits based upon 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.

As of September 30, 2014, our credit exposure included a $0.5 million exposure to non-investment grade energy marketing companies. The remainder of our credit exposure was concentrated primarily among retail utility customers, investment grade rated companies, cooperative utilities and federal agencies. Our derivative and hedging activities recorded in the accompanying Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Income (Loss) and Condensed Consolidated Statements of Comprehensive Income (Loss) are detailed below and in Note 9.

Oil and Gas

We produce natural gas 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 OTC swaps, exchange traded futures and related options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on these instruments. These transactions were designated at inception as cash flow hedges, documented under accounting standards for derivatives and hedging, and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

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

The contract or notional amounts, terms of our commodity derivatives, and the derivative balances for our Oil and Gas segment reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	September 30, 2014		December 31, 2013		September 30, 2013	
	Crude Oil Futures, Swaps and Options	Natural Gas Futures and Swaps	Crude Oil Futures, Swaps and Options	Natural Gas Futures and Swaps	Crude Oil Futures, Swaps and Options	Natural Gas Futures and Swaps
Notional [(a)]	391,500	7,930,000	412,500	7,082,500	499,500	9,874,000
Maximum terms in months [(b)]	1	1	3	1	3	1
Derivative assets, current	$—	$—	$55	$—	$13	$113
Derivative assets, non-current	$—	$—	$—	$—	$—	$—
Derivative liabilities, current	$—	$—	$—	$—	$98	$52
Derivative liabilities, non-current	$—	$—	$—	$—	$—	$—

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

(b) Refers to the tenor of the derivative instrument. Assets and liabilities are classified as current/non-current based on the production month hedged and the corresponding settlement of the derivative instrument.

A $0.7 million gain is included in AOCI at September 30, 2014, and would be realized over the next 12 months if market prices remained equal to September 30, 2014 prices. Future realized gains or losses fluctuate with market prices.

Utilities

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used for Electric Utility 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 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. Unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Condensed Consolidated Balance Sheets in accordance with state commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Condensed Consolidated Statements of Income (Loss).

The contract or notional amounts and terms of the natural gas derivative commodity instruments held at our Utilities were as follows, as of:

	September 30, 2014		December 31, 2013		September 30, 2013	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	16,290,000	74	17,930,000	84	14,010,000	74
Natural gas options purchased	7,070,000	6	3,890,000	8	6,810,000	6
Natural gas basis swaps purchased	12,025,000	63	14,785,000	60	9,790,000	63

(a) Term reflects the maximum forward period hedged.

We had the following derivative balances related to the hedges in our Utilities reflected in our Condensed Consolidated Balance Sheets as of (in thousands):

	September 30, 2014	December 31, 2013	September 30, 2013
Derivative assets, current	$—	$662	$—
Derivative assets, non-current	$—	$—	$—
Derivative liabilities, non-current	$—	$—	$—
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$7,470	$7,567	$10,652

Financing Activities

We entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	September 30, 2014	December 31, 2013	September 30, 2013	
	Interest Rate Swaps [(a)]	Interest Rate Swaps [(a)]	Interest Rate Swaps [(b)]	De-designated Interest Rate Swaps [(c)]
Notional	$75,000	$75,000	$150,000	$250,000
Weighted average fixed interest rate	4.97 %	4.97 %	5.04 %	5.67 %
Maximum terms in years	2.25	3.00	3.25	0.25
Derivative liabilities, current	$3,397	$3,474	$7,039	$58,755
Derivative liabilities, non-current	$3,273	$5,614	$11,388	$—

(a) These swaps are designated to borrowings on our Revolving Credit Facility, and are priced using three-month LIBOR, matching the floating portion of the related debt.

(b) At September 30, 2013, $75 million of these interest rate swaps was designated to borrowings on our Revolving Credit Facility and $75 million was designated to borrowings on our project financing debt at Black Hills Wyoming. These swaps were priced using three-month LIBOR, matching the floating portion of the related debt. The portion of the swaps that was designated to Black Hills Wyoming was settled during the fourth quarter of 2013 upon repayment of the Black Hills Wyoming project financing.

(c) These swaps were settled during the fourth quarter of 2013.

Based on September 30, 2014, market interest rates and balances related to our interest rate swaps, a loss of approximately $3.4 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Estimated and actual realized gains or losses will change during future periods as market interest rates change.

Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income (Loss) were as follows (in thousands):

Three Months Ended September 30, 2014

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion)	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	$152	Interest expense	$(925)		$—
Commodity derivatives	4,833	Revenue	(1,135)		—
Total	$4,985		$(2,060)		$—

Three Months Ended September 30, 2013

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion)	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	$(907)	Interest expense	$(1,844)		$—
Commodity derivatives	(2,140)	Revenue	(168)		—
Total	$(3,047)		$(2,012)		$—

Nine Months Ended September 30, 2014

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion)	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	$(277)	Interest expense	$(2,745)		$—
Commodity derivatives	(1,376)	Revenue	(2,697)		—
Total	$(1,653)		$(5,442)		$—

Nine Months Ended September 30, 2013

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion)	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	$141	Interest expense	$(5,460)	$—
Commodity derivatives	86	Revenue	896	—
Total	$227		$(4,564)	$—

(9) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

The accounting guidance for fair value measurements requires certain disclosures about assets and liabilities measured at fair value. This guidance establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments. For additional information see Notes 1, 8 and 10 to the Consolidated Financial Statements included in our 2013 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 option contracts for our Oil and Gas segment are valued using the market approach and can include calls and puts. Fair value was derived using quoted 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.

- The commodity basis swaps for our Oil and Gas segment are valued using the market approach with the instrument's current forward price strip hedged for the same quantity and date and discounted based on the three-month LIBOR. We utilize observable inputs which support a Level 2 disclosure.

Utilities Segments:

- The commodity contracts for our Utilities Segments, valued using the market approach, include exchange-traded futures, options and basis swaps (Level 2) and OTC basis swaps (Level 3) for natural gas contracts. For Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For Level 3 assets and liabilities, fair value was derived using average price quotes from the OTC contract broker and an independent third-party market participant because these instruments are not traded on an exchange.

Corporate Activities:

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

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 our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments. A discussion of fair value of financial instruments is included in Note 10:

	As of September 30, 2014				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	322	—	(322)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	1,545	—	(1,545)	—
Commodity derivatives — Utilities	—	4,029	—	(4,029)	—
Total	$—	$5,896	$—	$(5,896)	$—
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	487	—	(487)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	865	—	(865)	—
Commodity derivatives — Utilities	—	8,679	—	(8,679)	—
Interest rate swaps	—	6,670	—	—	6,670
Total	$—	$16,701	$—	$(10,031)	$6,670

	As of December 31, 2013				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	130	—	(75)	55
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	815	—	(815)	—
Commodity derivatives —Utilities	—	3,030	—	(2,368)	662
Total	$—	$3,975	$—	$(3,258)	$717
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	1,229	—	(1,229)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	531	—	(531)	—
Commodity derivatives — Utilities	—	9,100	—	(9,100)	—
Interest rate swaps	—	9,088	—	—	9,088
Total	$—	$19,948	$—	$(10,860)	$9,088

	As of September 30, 2013				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$2	$—	$—	$2
Basis Swaps -- Oil	—	51	—	(40)	11
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	1,752	—	(1,639)	113
Commodity derivatives — Utilities	—	2,351	—	(2,351)	—
Total	$—	$4,156	$—	$(4,030)	$126
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$142	$—	$(77)	$65
Basis Swaps -- Oil	—	1,318	—	(1,284)	34
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	232	—	(181)	51
Commodity derivatives — Utilities	—	10,747	—	(10,747)	—
Interest rate swaps	—	83,142	—	(5,960)	77,182
Total	$—	$95,581	$—	$(18,249)	$77,332

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 reflecting 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; however, the amounts do not include net cash collateral on deposit in margin accounts at September 30, 2014, December 31, 2013, and September 30, 2013, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Condensed Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 8.

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

As of September 30, 2014

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$1,174	$—
Commodity derivatives	Derivative assets — non-current	692	—
Commodity derivatives	Derivative liabilities — current	—	497
Commodity derivatives	Derivative liabilities — non-current	—	856
Interest rate swaps	Derivative liabilities — current	—	3,397
Interest rate swaps	Derivative liabilities — non-current	—	3,273
Total derivatives designated as hedges		$1,866	$8,023
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	48
Commodity derivatives	Derivative liabilities — non-current	—	4,602
Total derivatives not designated as hedges		$—	$4,650

As of December 31, 2013

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$248	$—
Commodity derivatives	Derivative assets — non-current	698	—
Commodity derivatives	Derivative liabilities — current	—	1,541
Commodity derivatives	Derivative liabilities — non-current	—	219
Interest rate swaps	Derivative liabilities — current	—	3,474
Interest rate swaps	Derivative liabilities — non-current	—	5,614
Total derivatives designated as hedges		$946	$10,848
Derivatives not designated as hedges:			

Commodity derivatives	Derivative assets — current	$662	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	6,732
Total derivatives not designated as hedges		$662	$6,732

As of September 30, 2013

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$846	$—
Commodity derivatives	Derivative assets — non-current	959	—
Commodity derivatives	Derivative liabilities — current	—	1,317
Commodity derivatives	Derivative liabilities — non-current	—	375
Interest rate swaps	Derivative liabilities — current	—	7,039
Interest rate swaps	Derivative liabilities — non-current	—	11,388
Total derivatives designated as hedges		$1,805	$20,119
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	1,795
Commodity derivatives	Derivative liabilities — non-current	—	6,601
Interest rate swaps	Derivative liabilities — current	—	64,715
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives not designated as hedges		$—	$73,111

(10) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 9, were as follows (in thousands) as of:

	September 30, 2014		December 31, 2013		September 30, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$11,939	$11,939	$7,841	$7,841	$13,637	$13,637
Restricted cash and equivalents [(a)]	$1,918	$1,918	$2	$2	$6,782	$6,782
Notes payable [(a)]	$184,000	$184,000	$82,500	$82,500	$138,300	$138,300
Long-term debt, including current maturities [(b)]	$1,382,519	$1,547,359	$1,396,948	$1,491,422	$1,211,673	$1,325,729

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

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

(11) OTHER COMPREHENSIVE INCOME (LOSS)

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

	Location on the Condensed Consolidated Statements of Income (Loss)	Amount Reclassified from AOCI			
		Three Months Ended		Nine Months Ended	
		September 30, 2014	September 30, 2013	September 30, 2014	September 30, 2013
Gains (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$925	$1,844	$2,745	$5,460
Commodity contracts	Revenue	1,135	168	2,697	(896)
		2,060	2,012	5,442	4,564
Income tax	Income tax benefit (expense)	(732)	(586)	(1,931)	(1,469)
Reclassification adjustments related to cash flow hedges, net of tax		$1,328	$1,426	$3,511	$3,095
Amortization of defined benefit plans:					
Prior service cost	Utilities - Operations and maintenance	$(26)	$(31)	$(77)	$(93)
	Non-regulated energy operations and maintenance	(22)	(32)	(93)	(96)
Actuarial gain (loss)	Utilities - Operations and maintenance	158	425	473	1,267

	Non-regulated energy operations and maintenance	88	275	274	823
		198	637	577	1,901
Income tax	Income tax benefit (expense)	(69)	(220)	(202)	(663)
Reclassification adjustments related to defined benefit plans, net of tax		$129	$417	$375	$1,238

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

	Derivatives Designated as Cash Flow Hedges		Employee Benefit Plans		Total	
Balance as of December 31, 2012	$(15,713	)	$(19,775	)	$(35,488	)
Other comprehensive income (loss), net of tax	(1,193	)	457		(736	)
Balance as of March 31, 2013	(16,906	)	(19,318	)	(36,224	)
Other comprehensive income (loss), net of tax	5,079		364		5,443	
Balance as of June 30, 2013	(11,827	)	(18,954	)	(30,781	)
Other comprehensive income (loss), net of tax	(657	)	417		(240	)
Ending Balance September 30, 2013	$(12,484	)	$(18,537	)	$(31,021	)
Balance as of December 31, 2013	$(7,133	)	$(10,289	)	$(17,422	)
Other comprehensive income (loss), net of tax	(1,478	)	311		(1,167	)
Balance as of March 31, 2014	(8,611	)	(9,978	)	(18,589	)
Other comprehensive income (loss), net of tax	(556	)	(296	)	(852	)
Balance as of June 30, 2014	(9,167	)	(10,274	)	(19,441	)
Other comprehensive income (loss), net of tax	4,473		129		4,602	
Ending Balance Sept. 30, 2014	$(4,694	)	$(10,145	)	$(14,839	)

(12) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Nine months ended	September 30, 2014 (in thousands)		September 30, 2013	
Non-cash investing and financing activities from continuing operations—				
Property, plant and equipment acquired with accrued liabilities	$52,484		$47,214	
Increase (decrease) in capitalized assets associated with asset retirement obligations	$(2,785	)	$—	
Cash (paid) refunded during the period for continuing operations—				
Interest (net of amounts capitalized)	$(46,086	)	$(57,175	)
Income taxes, net	$(396	)	$(4,924	)

(13) 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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Service cost	$1,362	$1,608	$4,086	$4,824
Interest cost	3,963	3,825	11,889	11,475
Expected return on plan assets	(4,516)	(4,654)	(13,549)	(13,962)
Prior service cost	16	16	47	48
Net loss (gain)	1,201	3,062	3,604	9,186
Net periodic benefit cost	$2,026	$3,857	$6,077	$11,571

Non-pension Defined Benefit Postretirement Healthcare Plans

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Service cost	$425	$419	$1,275	$1,257
Interest cost	480	417	1,439	1,251
Expected return on plan assets	(21)	(20)	(64)	(60)
Prior service cost (benefit)	(107)	(125)	(321)	(375)
Net loss (gain)	40	121	120	363
Net periodic benefit cost	$817	$812	$2,449	$2,436

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Service cost	$374	$348	$1,123	$1,044
Interest cost	362	332	1,085	996
Prior service cost	1	1	2	3
Net loss (gain)	124	198	373	594
Net periodic benefit cost	$861	$879	$2,583	$2,637

Contributions

We made contributions to the benefit plans during 2014 and anticipate that we will make contributions to the benefit plans during 2015. Contributions to the Defined Benefit Pension Plans are cash contributions made directly to the Pension Plan Trust accounts. Contributions to the Healthcare and Supplemental Plan are made in the form of benefit payments. Contributions and anticipated contributions are as follows (in thousands):

	Contributions Made	Contributions Made	Additional Contributions	Contributions
	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014	Anticipated for 2014	Anticipated for 2015
Defined Benefit Pension Plans	$10,200	$10,200	$—	$12,500
Non-pension Defined Benefit Postretirement Healthcare Plans	$956	$2,868	$956	$3,822
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$373	$1,118	$373	$1,494

(14) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 18 of our Notes to the Consolidated Financial Statements in our 2013 Annual Report on Form 10-K except for those described below.

Power Purchase Agreement

As disclosed in footnote 16, Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements, the most significant of which involves a 20-year economy energy PPA. The PPA contains a sharing arrangement where Black Hills Wyoming shares with the City of Gillette savings from wholesale power purchases made on behalf of the City when power costs are less than operating the generating unit. In addition, other ancillary agreements include agreements for Black Hills Wyoming to operate CTII, provide shared facilities, and provide generation dispatch services. Black Hills Wyoming’s previous power sales agreement that sold all of CTII’s output to Cheyenne Light expired on August 31, 2014.

Natural Gas Delivery Agreement

In 2012, we entered into a ten-year gas gathering and processing contract for natural gas production from our properties in the Piceance Basin in Colorado, under which we pay a gathering fee per Mcf. The contract requires us to deliver a minimum of 20,000 Mcf per day. This agreement became effective in first quarter of 2014 upon completion of the processing infrastructure capable of handling the committed volumes.

Reimbursement Agreement

We have a reimbursement agreement in place with Wells Fargo on behalf of Cheyenne Light for the 2009A bonds of $10 million due in 2027 and the 2009B bonds of $7.0 million due in 2021. In the case of default, we hold the assumption of liability for drawings on Cheyenne Light’s Letter of Credit attached to these bonds.

Other Commitments

Construction was completed on Cheyenne Prairie, a 132 MW, $222 million natural gas-fired electric generating facility jointly owned by Cheyenne Light and Black Hills Power. The facility was placed into commercial operation on October 1, 2014. Included in the total cost of Cheyenne Prairie, are contingencies of approximately $2.5 million remaining on contracts pertaining to site finishing, contractor close-outs, and construction management demobilization and cleanup. Resolution of these contingencies is expected in the fourth quarter of 2014.

Oil Creek Fire

On June 29, 2012, a forest and grassland fire occurred in the western Black Hills of Wyoming. A state fire investigator concluded that the fire was caused by the failure of a transmission structure owned, operated and maintained by Black Hills Power. On April 16, 2013, a lawsuit was filed in the United States District Court for the District of Wyoming, which forty-seven plaintiffs and the State of Wyoming have now joined, asserting claims for damages against Black Hills Power. The claims include allegations of negligence, negligence per se, common law nuisance, and trespass. In addition to claims for these compensatory damages, the lawsuit seeks recovery of punitive damages. Our investigation of the cause and origin of the fire is ongoing. We have denied and will vigorously defend all claims arising out of the fire, pending the completion of our investigation. We cannot predict the outcome of our investigation, the viability of alleged claims or the outcome of the litigation.

Civil litigation of this kind, however, is likely to lead to settlement negotiations, including negotiations prompted by pre-trial civil court procedures. We believe such negotiations would effect a settlement of all claims. Regardless of whether the litigation is determined at trial or through settlement, we expect to incur significant investigation, legal and expert services expenses associated with the litigation. We maintain insurance coverage to limit our exposure to losses due to civil liability claims, and related litigation expense. The deductible applicable to some types of claims arising out of this fire is $1.0 million. We expect this coverage to limit our exposure, and we will pursue recoveries to the maximum extent available under the policies. Based upon information currently available, we believe that a loss associated with settlement of pending claims is probable. Accordingly, as of September 30, 2014, we recorded a loss contingency liability related to these claims, and we recorded a receivable for costs we believe are reimbursable and probable of recovery under our insurance coverage. Both of these entries reflect our reasonable estimate of probable future litigation expense and settlement costs; we did not base these contingencies on any determination that it is probable we would be found liable for these claims were they to be litigated.

Given the uncertainty of litigation, however, a loss related to the fire, the litigation and related claims in excess of the loss we have determined to be probable is reasonably possible. However, we cannot reasonably estimate the amount of such possible loss because our investigation and review of damage claims documentation is ongoing, and there are significant factual and legal issues to be resolved. Further claims may be presented by these and other parties. While we have received claims seeking recovery for fire suppression, reclamation and rehabilitation costs, damage to fencing and other personal property, alleged injury to timber, grass or hay, livestock and related operations, and diminished value of real estate, currently totaling $50 million, we are not yet able, for the reasons described above, to reasonably estimate the amount of any reasonable possible losses in excess of the amount we have accrued. Based upon information currently available, however, management does not expect the outcome of the claims to have a material adverse effect upon our consolidated financial condition, results of operations or cash flows.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of September 30, 2014, we were in compliance with the debt covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at September 30, 2014:

- 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. As of September 30, 2014, the restricted net assets at our Utilities Group were approximately $73 million.

(15) GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include indemnification for reclamation and surety bonds.

We had the following guarantees in place (in thousands):

Nature of Guarantee	Maximum Exposure at September 30, 2014	Expiration
Indemnification for subsidiary reclamation/surety bonds [(a)]	$63,900	Ongoing

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(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Condensed Consolidated Balance Sheets.

During the second quarter of 2014, guarantees of Black Hills Utility Holdings' payment obligations up to $70 million arising from commodity transactions for natural gas supply were removed, primarily due to improvement of the corporate credit rating, as well as the conversion of certain guarantees to letters of credit.

(16) SALE OF OPERATING ASSET

On September 3, 2014, Black Hills Wyoming closed the sale of its 40 MW CTII natural-gas fired generating unit to the City of Gillette, Wyoming for approximately $22 million, upon expiration on August 31, 2014 of the PPA with Cheyenne Light. Consideration for the sale included ancillary agreements, the most significant of which includes Black Hills Wyoming providing services to the City of Gillette through an economy energy PPA over a term of 20 years. Black Hills Wyoming will recognize a $4.9 million gain on sale over the 20 year term of the agreements. The deferred gain is recorded in Other deferred credits and other liabilities at September 30, 2014 on the accompanying Condensed Consolidated Balance Sheet.

(17) SUBSEQUENT EVENT

Long-Term Debt

On October 1, 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Black Hills Power issued $85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light issued $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. Proceeds from Black Hills Power's bond sale also funded the early redemption of its 5.35% $12 million pollution control revenue bonds, originally due October 1, 2024.

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

We are a growth-oriented, vertically-integrated energy company operating principally in the United States with two major business groups — Utilities and Non-regulated Energy. We report our business groups in the following financial segments:

Business Group	Financial Segment
Utilities	Electric Utilities Gas Utilities
Non-regulated Energy	Power Generation Coal Mining Oil and Gas

Our Utilities Group consists of our Electric and Gas Utilities segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 203,500 customers in South Dakota, Wyoming, Colorado and Montana; and also distributes natural gas to approximately 35,500 Cheyenne Light customers in Wyoming. Our Gas Utilities serve approximately 538,000 natural gas customers in Colorado, Iowa, Kansas and Nebraska. Our Non-regulated Energy Group consists of our Power Generation, Coal Mining and Oil and Gas segments. Our Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy principally to our utilities under long-term contracts. Our Coal Mining segment produces coal at our coal mine near Gillette, Wyoming and sells the coal primarily to on-site, mine-mouth power generation facilities. Our Oil and Gas segment engages in exploration, development and production of crude oil and natural gas, primarily in the Rocky Mountain region.

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2014 and 2013, and our financial condition as of September 30, 2014, December 31, 2013 and September 30, 2013, 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 61.

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

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. Net income (loss) for the three months ended September 30, 2014 was $27 million, or $0.60 per share, compared to Net income (loss) of $23 million, or $0.52 per share, reported for the same period in 2013.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. Net income (loss) for the nine months ended September 30, 2014 was $95 million, or $2.13 per share, compared to Net income (loss) of $97 million, or $2.18 per share, reported for the same period in 2013.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	Variance	2014	2013	Variance
Revenue						
Utilities	$253,286	$239,196	$14,090	$959,108	$865,506	$93,602
Non-regulated Energy	51,065	51,711	(646)	155,540	147,255	8,285
Corporate activities	—	—	—	—	—	—
Inter-company eliminations	(32,264)	(31,000)	(1,264)	(99,155)	(92,357)	(6,798)
	$272,087	$259,907	$12,180	$1,015,493	$920,404	$95,089
Net income (loss)						
Electric Utilities	$18,154	$15,097	$3,057	$44,156	$38,063	$6,093
Gas Utilities	1,597	(1,450)	3,047	28,289	20,225	8,064
Utilities	19,751	13,647	6,104	72,445	58,288	14,157
Power Generation	7,829	6,707	1,122	23,096	17,382	5,714
Coal Mining	2,638	2,142	496	7,118	5,180	1,938
Oil and Gas	(3,110)	(1,682)	(1,428)	(6,792)	(3,699)	(3,093)
Non-regulated Energy	7,357	7,167	190	23,422	18,863	4,559
Corporate activities and eliminations (a)	(272)	2,310	(2,582)	(1,093)	19,688	(20,781)
Net income (loss)	$26,836	$23,124	$3,712	$94,774	$96,839	$(2,065)

(a) Corporate activities for the three and nine months ended September 30, 2013 include a $2 million and a $19 million net after-tax non-cash mark-to-market gain on certain interest rate swaps. These same interest rate swaps were settled in November 2013.

Overview of Business Segments and Corporate Activity

Utilities Group

- Gas Utilities experienced cooler weather during the three months ended September 30, 2014 compared to the three months ended September 30, 2013. The third quarter is well outside of the normal peak heating season; however, heating degree days increased 73% compared to the same period in 2013. Year-to-date results were favorably impacted primarily by colder weather incurred mostly during the first quarter of 2014. Heating degree days were 3% higher for the nine months ended September 30, 2014, compared to the same period in 2013. Heating degree days for the three and nine months ended September 30, 2014 were 6% and 12% higher than normal, respectively, compared to 38% lower and 8% higher than normal for the same periods in 2013.

- Mild weather was a contributing factor for our Electric Utilities for the three and nine months ended September 30, 2014. Weather related demand during the peak summer months was tempered by significantly cooler temperatures within our service territories. Cooling degree days were 26% and 29% lower for the three and nine months ended September 30, 2014, respectively, when compared to the same periods in 2013. Compared to normal temperatures, cooling degree days were 12% and 11% lower than normal for the three and nine months ended September 30, 2014, respectively, and 18% and 24% higher than normal for the same periods in 2013.

- BHC continued its efforts to acquire smaller public and municipal gas distribution systems adjacent to our existing service territories. On October 14, 2014, we announced an agreement to acquire Energy West Wyoming, Inc., a Wyoming gas utility, and pipeline assets of Gas Natural, Inc., for $17 million. The gas utility serves approximately 6,700 customers, including service to Cody, Ralston, and Meeteetse, Wyoming. The pipeline assets include a 30 mile gas transmission pipeline, and a 42 mile gas gathering pipeline, both located near the utility service territory. During the first quarter of 2014, we acquired an additional gas system in Kansas, adding approximately 70 customers, and we announced the pending acquisition of assets serving approximately 400 customers in northeast Wyoming.

- On October 24, 2014, a settlement agreement was reached between Kansas Gas, the KCC, and intervenors to increase base rates by $5.2 million. A hearing is scheduled for November 12, 2014, and a final commission order is expected by January 6, 2015, with new rates effective by mid-January.

- On October 1, 2014, Black Hills Power and Cheyenne Light placed into commercial service their jointly-owned Cheyenne Prairie generating station. Cheyenne Prairie is a 132 MW, $222 million natural gas-fired generating facility built to serve Black Hills Power and Cheyenne Light customers. Cheyenne Prairie was constructed on time and on budget. Construction financing costs were recovered through construction financing riders. New rates were also implemented on October 1, 2014 for Black Hills Power and Cheyenne Light in Wyoming, as previously approved by the WPSC.

- On October 1, 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Black Hills Power issued $85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light issued $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. Proceeds from Black Hills Power’s bond sale also funded the early redemption of its 5.35% $12 million pollution control revenue bonds, originally due October 1, 2024.

- Black Hills Power and Cheyenne Light each received approval from the WPSC on rate cases associated with Cheyenne Prairie. On August 21, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Black Hills Power of approximately $2.2 million for annual electric revenue, effective October 1, 2014. The settlement also included a return on equity of 9.9% and a capital structure of 53.3% equity and 46.7% debt. On July 31, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Cheyenne Light of $8.4

million and $0.8 million for annual electric and natural gas revenue, respectively, effective October 1, 2014. The settlement also included a return on equity of 9.9%, and a capital structure of 54% equity and 46% debt.

- On July 22, 2014, Black Hills Power filed a CPCN with the WPSC to construct the Wyoming portion of a $54 million, 230-kV, 144 mile-long transmission line that would connect the Teckla Substation in northeast Wyoming, to the Lange Substation near Rapid City, South Dakota. On June 30, 2014, Black Hills Power filed an application with the SDPUC, for a permit to construct the South Dakota portion of this line. Approval by the WPSC and SDPUC is anticipated in the fourth quarter of 2014.

- On May 5, 2014, Colorado Electric issued an all-source generation request for approximately 42 MW of summer seasonal firm capacity in 2017, 2018, and 2019, and up to 60 MW of eligible renewable energy resources to serve its customers in southern Colorado. Colorado IPP submitted solar and wind bids in response to this request. Proposed bids were due by July 31, 2014, and pending Colorado Electric’s review of the bids and associated regulatory proceedings, a CPUC decision on Colorado Electric’s portfolio of generation resources is expected by the end of February 2015.

- On April 30, 2014 Colorado Electric filed a rate request with the CPUC to recover increased operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm, placed in service late 2012. The filing also seeks to implement a rider to recover a return on the construction costs for a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant. On October 28, 2014, an administrative law judge issued a recommended decision which incorporates a $2 million revenue increase, a 9.83% return on equity and a capital structure of approximately 49.8% equity and 50.2% debt. The recommended decision also approves the implementation of the rider. The recommended decision is subject to exceptions and final commission approval with rates effective by the end of 2014.

- On April 25, 2014 Cheyenne Light received FERC approval to establish rates for transmission services under their Open Access Transmission Tariff, effective May 3, 2014. The approval includes a return on equity of 10.6% and a capital structure of 54% equity and 46% debt.

- On March 31, 2014, Black Hills Power filed a rate request with the SDPUC to increase annual revenue by $14.6 million to recover operating expenses and infrastructure investments, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25%, and a capital structure of approximately 53.3% equity and 46.7% debt. Interim rates were implemented on October 1, 2014 when Cheyenne Prairie commenced commercial operations. A final ruling from the SDPUC is expected in the first quarter of 2015.

- On March 21, 2014, Black Hills Power retired the Ben French, Neil Simpson I, and Osage coal-fired power plants. These three plants totaling 81 MW were closed because of federal environmental regulations. These plants were largely replaced by Black Hills Power’s share of Cheyenne Prairie.

- On February 25, 2014, the CPUC issued a final order after rehearing, approving a CPCN for the retirement of Pueblo Unit #5 and #6, effective December 31, 2013.

Non-regulated Energy Group

- Oil and Gas production volumes increased 6% for the three and nine months ended September 30, 2014 compared to the same periods in 2013. The average hedged price received decreased for natural gas by 4% for the three months ended September 30, 2014 and increased by 14% for the nine months ended September 30, 2014, compared to the same periods in 2013. The average hedged price received for oil decreased by 15% and 10%, respectively, for the three and nine months ended September 30, 2014 compared to the same periods in 2013.

- On September 3, 2014, Black Hills Wyoming closed the sale of its 40 MW CTII natural-gas fired generating unit to the City of Gillette, Wyoming for approximately $22 million, upon expiration on August 31, 2014 of the PPA with Cheyenne Light. As part of the sale, Black Hills Wyoming will provide services to the City of Gillette through ancillary agreements, including an economy energy PPA. The sale resulted in a deferred gain of $4.9 million which Black Hills Wyoming will recognize equally over the twenty year term of the ancillary agreements.

- Our southern Piceance Basin drilling program continued in 2014. During the third quarter, two Mancos Shale wells were drilled, cased and cemented, and drilling operations commenced on a third well. On March 6, 2014, the Summit

Midstream cryogenic gas processing plant with a capacity of 20,000 Mcf per day started serving the company’s gas production in the southern Piceance Basin, including the two Mancos Shale wells placed on production during the first quarter.

Corporate Activities

- On June 13, 2014, Fitch upgraded the BHC credit rating to BBB+ with a stable outlook.

- On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options for which the borrowing rates were reduced under the amended agreement.

- On January 30, 2014, Moody’s upgraded the BHC credit rating to Baa1 from Baa2 with continued stable outlook.

- Consolidated interest expense decreased by approximately $5.9 million and $17 million for the three and nine months ended September 30, 2014, respectively, compared to the three and nine months ended September 30, 2013, due primarily to the refinancing activities occurring during the fourth quarter of 2013.

Operating Results

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

Utilities Group

We report two segments within the Utilities Group: Electric Utilities and Gas Utilities. The Electric Utilities segment includes the regulated electric operations of Black Hills Power, Colorado Electric and the regulated electric and natural gas operations of Cheyenne Light. The Gas Utilities segment includes the regulated natural gas utility operations of Black Hills Energy in Colorado, Iowa, Kansas and Nebraska.

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

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

Electric Utilities

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	Variance	2014	2013	Variance
	(in thousands)					
Revenue — electric	$169,834	$167,152	$2,682	$492,743	$469,300	$23,443
Revenue — gas	4,717	4,252	465	25,794	22,766	3,028
Total revenue	174,551	171,404	3,147	518,537	492,066	26,471
Fuel, purchased power and cost of gas — electric	75,190	70,859	4,331	223,332	203,897	19,435
Purchased gas — gas	2,014	1,579	435	14,339	10,532	3,807
Total fuel, purchased power and cost of gas	77,204	72,438	4,766	237,671	214,429	23,242
Gross margin — electric	94,644	96,293	(1,649)	269,411	265,403	4,008
Gross margin — gas	2,703	2,673	30	11,455	12,234	(779)
Total gross margin	97,347	98,966	(1,619)	280,866	277,637	3,229
Operations and maintenance	39,052	41,145	(2,093)	121,923	119,363	2,560
Depreciation and amortization	19,635	19,368	267	57,996	58,194	(198)
Total operating expenses	58,687	60,513	(1,826)	179,919	177,557	2,362
Operating income	38,660	38,453	207	100,947	100,080	867
Interest expense, net	(11,730)	(14,089)	2,359	(35,572)	(42,296)	6,724
Other income (expense), net	330	13	317	938	471	467
Income tax benefit (expense)	(9,106)	(9,280)	174	(22,157)	(20,192)	(1,965)
Net income (loss)	$18,154	$15,097	$3,057	$44,156	$38,063	$6,093

Revenue - Electric (in thousands)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Residential:				
Black Hills Power	$15,941	$16,951	$50,333	$46,928
Cheyenne Light	8,982	8,816	26,822	26,453
Colorado Electric	26,104	27,438	72,099	73,388
Total Residential	51,027	53,205	149,254	146,769
Commercial:				
Black Hills Power	24,747	23,319	67,475	59,716
Cheyenne Light	15,682	14,738	45,313	41,981
Colorado Electric	23,989	23,531	68,980	66,345
Total Commercial	64,418	61,588	181,768	168,042
Industrial:				
Black Hills Power	6,816	6,850	21,685	20,070
Cheyenne Light	7,538	5,522	22,066	15,721
Colorado Electric	9,515	9,872	28,088	29,156
Total Industrial	23,869	22,244	71,839	64,947
Municipal:				
Black Hills Power	964	1,078	2,602	2,639
Cheyenne Light	453	499	1,421	1,447
Colorado Electric	3,513	4,018	10,097	10,057
Total Municipal	4,930	5,595	14,120	14,143
Total Retail Revenue - Electric	144,244	142,632	416,981	393,901
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	5,551	5,847	15,622	16,540
Off-system Wholesale:				
Black Hills Power	6,278	8,123	20,764	22,222
Cheyenne Light	1,810	1,603	5,984	6,379
Colorado Electric	879	2,035	4,874	5,275
Total Off-system Wholesale	8,967	11,761	31,622	33,876
Other Revenue:				
Black Hills Power	7,432	5,100	21,255	19,802
Cheyenne Light	625	594	1,912	1,642
Colorado Electric	3,015	1,218	5,351	3,539
Total Other Revenue	11,072	6,912	28,518	24,983
Total Revenue - Electric	$169,834	$167,152	$492,743	$469,300

	Three Months Ended September 30,		Nine Months Ended September 30,	
Quantities Generated and Purchased (in MWh)	2014	2013	2014	2013
Generated —				
Coal-fired:				
Black Hills Power [(a)]	414,551	457,329	1,168,641	1,334,441
Cheyenne Light	176,603	185,603	509,239	513,299
Colorado Electric	—	—	—	—
Total Coal-fired	591,154	642,932	1,677,880	1,847,740
Natural Gas and Oil:				
Black Hills Power	12,054	18,275	17,026	25,953
Cheyenne Light	—	—	—	—
Colorado Electric [(b)]	60,982	64,715	119,650	203,304
Total Natural Gas and Oil	73,036	82,990	136,676	229,257
Wind:				
Colorado Electric	8,862	9,916	36,420	32,923
Total Wind	8,862	9,916	36,420	32,923
Total Generated:				
Black Hills Power	426,605	475,604	1,185,667	1,360,394
Cheyenne Light	176,603	185,603	509,239	513,299
Colorado Electric	69,844	74,631	156,070	236,227
Total Generated	673,052	735,838	1,850,976	2,109,920
Purchased —				
Black Hills Power	336,160	361,390	1,132,425	1,098,772
Cheyenne Light	199,989	180,127	604,532	586,999
Colorado Electric [(b)]	490,378	534,830	1,427,677	1,402,005
Total Purchased	1,026,527	1,076,347	3,164,634	3,087,776
Total Generated and Purchased:				
Black Hills Power	762,765	836,994	2,318,092	2,459,166
Cheyenne Light	376,592	365,730	1,113,771	1,100,298
Colorado Electric	560,222	609,461	1,583,747	1,638,232
Total Generated and Purchased	1,699,579	1,812,185	5,015,610	5,197,696

(a) Decrease reflects the retirement of Neil Simpson I on March 21, 2014.

(b) Decrease year-to-date September 30, 2014, reflects a current year unplanned outage during the first quarter of 2014 due to a turbine bearing replacement and combustor upgrade at Pueblo Airport Generation Station, and utilization of Pueblo Airport Generating Station Units #1 and #2 in place of purchased power from Colorado IPP during the nine months ended September 30, 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Quantity (in MWh)	2014	2013	2014	2013
Residential:				
Black Hills Power	120,117	131,664	398,821	406,159
Cheyenne Light	64,468	66,278	192,451	202,403
Colorado Electric	169,760	178,187	455,647	474,378
Total Residential	354,345	376,129	1,046,919	1,082,940
Commercial:				
Black Hills Power	214,590	201,332	575,579	551,712
Cheyenne Light	140,871	136,062	396,971	397,705
Colorado Electric	186,988	187,770	519,406	538,815
Total Commercial	542,449	525,164	1,491,956	1,488,232
Industrial:				
Black Hills Power	96,443	98,174	302,208	295,662
Cheyenne Light	98,424	74,316	284,010	209,984
Colorado Electric	112,401	102,156	313,608	273,572
Total Industrial	307,268	274,646	899,826	779,218
Municipal:				
Black Hills Power	9,387	10,691	24,781	26,621
Cheyenne Light	2,272	2,412	6,896	7,150
Colorado Electric	34,765	38,749	92,838	85,844
Total Municipal	46,424	51,852	124,515	119,615
Total Retail Quantity Sold	1,250,486	1,227,791	3,563,216	3,470,005
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	83,714	87,092	250,941	268,529
Off-system Wholesale:				
Black Hills Power (a)	171,189	261,567	595,483	777,854
Cheyenne Light	45,066	47,120	139,672	178,942
Colorado Electric	17,754	63,529	98,678	133,544
Total Off-system Wholesale	234,009	372,216	833,833	1,090,340
Total Quantity Sold:				
Black Hills Power	695,440	790,520	2,147,813	2,326,537
Cheyenne Light	351,101	326,188	1,020,000	996,184
Colorado Electric	521,668	570,391	1,480,177	1,506,153
Total Quantity Sold	1,568,209	1,687,099	4,647,990	4,828,874
Other Uses, Losses or Generation, net (b):				
Black Hills Power	67,325	46,474	170,279	132,629
Cheyenne Light	25,491	39,542	93,771	104,114
Colorado Electric	38,554	39,070	103,570	132,079
Total Other Uses, Losses and Generation, net	131,370	125,086	367,620	368,822

Total Energy	1,699,579	1,812,185	5,015,610	5,197,696

(a) The three and nine months ended September 30, 2014 reflect plant outages related to unit contingent contracts.

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

Degree Days	Three Months Ended September 30,			
	2014		2013	
	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Heating Degree Days:				
Black Hills Power	241	15 %	107	(49)%
Cheyenne Light	220	(20)%	182	(36)%
Colorado Electric	54	(37)%	25	(71)%
Combined [(a)]	151	(9)%	84	(50)%
Cooling Degree Days:				
Black Hills Power	382	(32)%	646	15 %
Cheyenne Light	286	(5)%	397	32 %
Colorado Electric	710	(3)%	851	17 %
Combined [(a)]	514	(12)%	691	18 %

Degree Days	Nine Months Ended September 30,			
	2014		2013	
	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Heating Degree Days:				
Black Hills Power	4,676	6 %	4,544	6 %
Cheyenne Light	4,617	3 %	4,665	4 %
Colorado Electric	3,357	2 %	3,527	2 %
Combined [(a)]	4,055	3 %	4,097	4 %
Cooling Degree Days:				
Black Hills Power	481	(28)%	724	8 %
Cheyenne Light	336	(5)%	520	48 %
Colorado Electric	919	(4)%	1,227	28 %
Combined [(a)]	654	(11)%	916	24 %

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

Electric Utilities Power Plant Availability	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Coal-fired plants [(a)]	97.0 %	97.6 %	92.4 %	96.8 %
Other plants [(b)]	95.6 %	95.8 %	87.9 %	96.7 %
Total availability	96.2 %	96.7 %	89.8 %	96.7 %

(a) The nine months ended September 30, 2014 reflect a planned annual outage at Neil Simpson II and an unplanned outage for a catalyst repair at Wygen III.

(b) The nine months ended September 30, 2014 include a planned outage at Ben French CT's #1 and #2 for a controls upgrade, and an unplanned outage due to a turbine bearing replacement and combustor upgrade at Pueblo Airport Generating Station.

Cheyenne Light Natural Gas Distribution

Included in the Electric Utilities is Cheyenne Light’s natural gas distribution system. The following table summarizes certain operating information for these natural gas distribution operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenue - Natural Gas (in thousands):				
Residential	$2,912	$2,719	$15,655	$14,284
Commercial	1,124	977	7,075	6,107
Industrial	465	356	2,368	1,759
Other Sales Revenue	216	200	696	616
Total Revenue - Natural Gas	$4,717	$4,252	$25,794	$22,766
Gross Margin (in thousands):				
Residential	$1,969	$1,977	$7,956	$8,611
Commercial	451	423	2,413	2,663
Industrial	67	73	390	344
Other Gross Margin	216	200	696	616
Total Gross Margin	$2,703	$2,673	$11,455	$12,234
Volumes Sold (Dth):				
Residential	183,327	172,136	1,669,219	1,757,397
Commercial	130,939	128,320	979,826	1,033,171
Industrial	77,175	66,027	453,660	430,186
Total Volumes Sold	391,441	366,483	3,102,705	3,220,754

Results of Operations for the Electric Utilities for the Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013: Net income for the Electric Utilities was $18 million for the three months ended September 30, 2014, compared to $15 million for the three months ended September 30, 2013, as a result of:

Gross margin decreased primarily due to a 26% decrease in cooling degree days compared to the same period in the prior year resulting in a $3.4 million decrease on lower demand and residential megawatt hours sold. Wholesale margins were also impacted by plant outages affecting unit specific contracts, resulting in a $0.7 million decrease in wholesale margins. These decreases were partially offset by increased rider margins of $1.4 million due to a return on additional investment in our generating facilities, and $1.0 million driven by service revenue on industrial load growth at Colorado Electric. Industrial megawatt hours sold increased 12% compared to the same period in the prior year, primarily driven by load growth at Cheyenne Light.

Operations and maintenance decreased primarily due to decreases in corporate expense allocations and outside services.

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

Interest expense, net decreased primarily due to lower interest rates from refinancing higher cost debt in the fourth quarter of 2013.

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

Income tax benefit (expense): The effective tax rate is lower in 2014 primarily due to a favorable true-up to the filed 2013 income tax return, in addition to an increase in flow-through tax adjustments.

Results of Operations for the Electric Utilities for the Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013: Net income for the Electric Utilities was $44 million for the nine months ended September 30, 2014, compared to $38 million for the nine months ended September 30, 2013, as a result of:

Gross margin increased primarily due to a return on additional investments which increased base electric margins by $3.6 million and increased rider margins by $6.7 million. Industrial megawatt hours sold increased by approximately 15%, primarily due to load growth at Cheyenne Light resulting in increased margins of $0.9 million. Non-regulated margins increased by $0.9 million driven primarily by service revenue on industrial growth opportunities at Colorado Electric. These increases are partially offset by a $3.7 million decrease from lower demand and residential megawatt hours sold driven by a 29% decrease in cooling degree days compared to the same period in the prior year, a $1.7 million decrease in wholesale volumes sold, a $1.3 million decrease from the TCA, a $0.7 million decrease from a construction savings incentive recognized in the prior year and a $0.8 million decrease due to higher purchased power costs within our PCA sharing mechanism. Our Cheyenne Light gas utility experienced a decrease in heating degree days, resulting in a $0.8 million decrease in retail natural gas sales.

Operations and maintenance increased primarily due to an increase in employee costs, generation maintenance, outside services and property taxes.

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

Interest expense, net decreased primarily due to refinancing higher cost debt in the fourth quarter of 2013.

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

Income tax benefit (expense): The effective tax rate is lower in 2014 primarily due to a favorable true-up to the filed 2013 income tax return, in addition to an increase in flow-through tax adjustments.

Gas Utilities

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	Variance	2014	2013	Variance
	(in thousands)					
Natural gas — regulated	$71,595	$60,931	$10,664	$418,177	$351,517	$66,660
Other — non-regulated services	7,140	6,861	279	22,394	21,923	471
Total revenue	78,735	67,792	10,943	440,571	373,440	67,131
Natural gas — regulated	32,614	23,999	8,615	255,654	197,522	58,132
Other — non-regulated services	3,896	3,634	262	11,293	10,868	425
Total cost of sales	36,510	27,633	8,877	266,947	208,390	58,557
Gross margin	42,225	40,159	2,066	173,624	165,050	8,574
Operations and maintenance	31,646	30,459	1,187	100,478	95,537	4,941
Depreciation and amortization	6,634	6,594	40	19,693	19,680	13
Total operating expenses	38,280	37,053	1,227	120,171	115,217	4,954
Operating income (loss)	3,945	3,106	839	53,453	49,833	3,620
Interest expense, net	(3,766)	(6,016)	2,250	(11,341)	(18,200)	6,859
Other income (expense), net	(3)	26	(29)	(1)	33	(34)
Income tax benefit (expense)	1,421	1,434	(13)	(13,822)	(11,441)	(2,381)
Net income (loss)	$1,597	$(1,450)	$3,047	$28,289	$20,225	$8,064

	Three Months Ended September 30,		Nine Months Ended September 30,	
Revenue (in thousands)	2014	2013	2014	2013
Residential:				
Colorado	$5,996	$5,007	$39,118	$34,651
Nebraska	14,032	11,850	94,443	83,634
Iowa	13,013	10,471	89,829	67,361
Kansas	8,796	8,166	52,421	46,551
Total Residential	41,837	35,494	275,811	232,197
Commercial:				
Colorado	1,411	1,253	8,168	6,691
Nebraska	3,330	2,436	27,986	25,781
Iowa	5,964	4,511	43,080	30,728
Kansas	2,520	2,208	17,815	15,049
Total Commercial	13,225	10,408	97,049	78,249
Industrial:				
Colorado	1,070	900	1,651	1,455
Nebraska	203	242	510	547
Iowa	615	457	2,928	1,911
Kansas	8,528	7,748	15,246	14,748
Total Industrial	10,416	9,347	20,335	18,661
Transportation:				
Colorado	124	98	666	726
Nebraska	2,054	1,958	10,326	9,069
Iowa	895	916	3,639	3,454
Kansas	1,654	1,402	5,710	4,904
Total Transportation	4,727	4,374	20,341	18,153
Other Sales Revenue:				
Colorado	25	17	92	(35)
Nebraska	528	491	1,882	1,731
Iowa	158	120	572	422
Kansas	678	680	2,094	2,139
Total Other Sales Revenue	1,389	1,308	4,640	4,257
Total Regulated Revenue	71,594	60,931	418,176	351,517
Non-regulated Services	7,141	6,861	22,395	21,923
Total Revenue	$78,735	$67,792	$440,571	$373,440

	Three Months Ended September 30,		Nine Months Ended September 30,	
Gross Margin (in thousands)	2014	2013	2014	2013
Residential:				
Colorado	$2,917	$2,791	$12,887	$12,913
Nebraska	9,064	8,374	39,877	37,740
Iowa	8,301	8,032	32,504	31,018
Kansas	6,025	5,915	24,137	23,044
Total Residential	26,307	25,112	109,405	104,715
Commercial:				
Colorado	497	480	2,164	2,048
Nebraska	1,504	1,264	8,440	8,191
Iowa	1,984	1,924	9,509	8,968
Kansas	1,263	1,139	5,942	5,302
Total Commercial	5,248	4,807	26,055	24,509
Industrial:				
Colorado	248	279	408	467
Nebraska	56	72	157	157
Iowa	45	43	191	206
Kansas	1,061	1,011	1,994	1,985
Total Industrial	1,410	1,405	2,750	2,815
Transportation:				
Colorado	124	98	666	726
Nebraska	2,054	1,958	10,326	9,069
Iowa	895	916	3,639	3,454
Kansas	1,654	1,402	5,710	4,904
Total Transportation	4,727	4,374	20,341	18,153
Other Sales Margins:				
Colorado	25	17	92	(35)
Nebraska	529	491	1,883	1,731
Iowa	158	120	572	422
Kansas	577	606	1,425	1,685
Total Other Sales Margins	1,289	1,234	3,972	3,803
Total Regulated Gross Margin	38,981	36,932	162,523	153,995
Non-regulated Services	3,244	3,227	11,101	11,055
Total Gross Margin	$42,225	$40,159	$173,624	$165,050

	Three Months Ended September 30,		Nine Months Ended September 30,	
Distribution Quantities Sold and Transportation (in Dth)	2014	2013	2014	2013
Residential:				
Colorado	537,302	471,618	4,577,702	4,661,845
Nebraska	876,069	646,900	9,140,645	8,441,465
Iowa	717,413	521,223	8,610,378	7,544,375
Kansas	542,998	463,083	5,140,443	4,723,982
Total Residential	2,673,782	2,102,824	27,469,168	25,371,667
Commercial:				
Colorado	162,936	167,060	1,053,938	999,653
Nebraska	325,327	231,394	3,285,506	3,267,020
Iowa	581,028	552,814	4,951,717	4,523,365
Kansas	249,809	224,078	2,183,324	1,976,165
Total Commercial	1,319,100	1,175,346	11,474,485	10,766,203
Industrial:				
Colorado	209,337	237,848	321,130	374,709
Nebraska	32,003	44,184	71,136	88,449
Iowa	71,188	87,726	384,761	359,822
Kansas	1,788,406	1,742,551	3,053,101	3,154,217
Total Industrial	2,100,934	2,112,309	3,830,128	3,977,197
Wholesale and Other:				
Nebraska	39	—	39	—
Kansas	18,836	12,359	119,743	86,568
Total Wholesale and Other	18,875	12,359	119,782	86,568
Total Distribution Quantities Sold	6,112,691	5,402,838	42,893,563	40,201,635
Transportation:				
Colorado	105,221	81,309	645,364	710,351
Nebraska	6,262,525	6,099,764	22,849,299	20,822,085
Iowa	4,193,172	4,422,788	14,669,877	14,892,528
Kansas	3,799,470	3,601,940	12,220,766	10,990,576
Total Transportation	14,360,388	14,205,801	50,385,306	47,415,540
Total Distribution Quantities Sold and Transportation	20,473,079	19,608,639	93,278,869	87,617,175

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

	Three Months Ended September 30,			
	2014		2013	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Colorado	117	(35)%	83	(54)%
Nebraska	95	(1)%	31	(68)%
Iowa	200	44%	138	(1)%
Kansas (a)	62	13%	16	(71)%
Combined (b)	137	6%	79	(38)%

	Nine Months Ended September 30,			
	2014		2013	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Colorado	3,900	—%	3,927	1%
Nebraska	3,947	6%	3,929	6%
Iowa	5,149	23%	4,754	13%
Kansas (a)	3,231	9%	3,202	8%
Combined (b)	4,371	12%	4,227	8%

(a) Kansas Gas has an approved weather normalization mechanism within its rate structure, which minimizes weather impact on gross margins.

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

Results of Operations for the Gas Utilities for the Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013: Net income for the Gas Utilities was $1.6 million for the three months ended September 30, 2014, compared to Net loss of $1.5 million for the three months ended September 30, 2013, as a result of:

Gross margin increased primarily due to cooler weather compared to the same period in the prior year resulting in higher residential and commercial volumes sold. Heating degree days were 73% higher for the three months ended September 30, 2014, compared to the same period in the prior year and 6% higher than normal. Also, a return on additional capital investments flowing through capital trackers resulted in increased surcharge revenue of $0.5 million.

Operations and maintenance increased primarily due to an increase in property taxes, and allowance for uncollectible account expense, partially offset by a decrease in corporate expense allocations.

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

Interest expense, net decreased primarily due to lower interest rates from refinancing higher cost debt in the fourth quarter of 2013.

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

Income tax benefit (expense): The effective tax rate for 2014 reflects a tax benefit due primarily to a favorable true-up to the filed 2013 income tax return, including an increase in an estimated flow-through tax adjustment.

Results of Operations for the Gas Utilities for the Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013: Net income for the Gas Utilities was $28 million for the nine months ended September 30, 2014, compared to Net income of $20 million for the nine months ended September 30, 2013, as a result of:

Gross margin increased primarily due to higher residential and commercial consumption, and transport volumes sold driven primarily by a 7% increase in heating degree days experienced through the peak months of the winter heating season as compared to the same period last year. Heating degree days were 3% higher for the nine months ended September 30, 2014, compared to the same period in the prior year and 12% higher than normal. Surcharge revenue increased by $2.5 million for the nine months ended September 30, 2014, including a return on additional capital investments flowing through capital trackers of $0.9 million, and an increase of $1.1 million is attributed to year over year customer growth.

Operations and maintenance increased primarily due to an increase in employee costs, allowance for uncollectible account expense, and property taxes.

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

Interest expense, net decreased primarily due to refinancing higher cost debt in the fourth quarter of 2013.

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

Income tax benefit (expense): The effective tax rate for 2014 reflects a tax benefit due primarily to a favorable true-up to the filed 2013 income tax return, including an increase in an estimated flow-through tax adjustment.

Regulatory Matters — Utilities Group

The following summarizes our recent state and federal rate case and initial surcharge orders (in millions):

	Type of Service	Date Requested	Effective Date	Revenue Amount Requested	Revenue Amount Approved
Cheyenne Light [a]	Electric/Gas	12/2013	10/2014	$14.1	$9.2
Black Hills Power [b]	Electric	1/2014	10/2014	$2.8	$2.2
Black Hills Power [c]	Electric	3/2014	10/2014	$14.6	pending
Iowa Gas [d]	Gas	2/2014	4/2014	$0.5	$0.5
Kansas Gas [e]	Gas	4/2014	pending	$7.3	pending
Colorado Electric [f]	Electric	4/2014	pending	$4.0	pending

(a) On July 31, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Cheyenne Light of $8.4 million and $0.8 million for annual electric and natural gas revenue, respectively, effective October 1, 2014. The settlement also included a return on equity of 9.9%, and a capital structure of 54% equity and 46% debt. The WPSC’s decision provides Cheyenne Light a return on its investment in Cheyenne Prairie and associated infrastructure, and provides recovery of its share of operating expenses for this natural gas-fired facility.

(b) On August 21, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Black Hills Power of approximately $2.2 million for annual electric revenue, effective October 1, 2014. The settlement also included a return on equity of 9.9% and a capital structure of 53.3% equity and 46.7% debt. The WPSC’s decision provides Black Hills Power a return on its investment in Cheyenne Prairie and associated infrastructure, and provides recovery of its share of operating expenses for this natural gas-fired facility.

(c) On March 31, 2014, Black Hills Power filed a rate request with the SDPUC to increase annual revenue by $14.6 million to recover operating expenses and infrastructure investments, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25%, and a capital structure of approximately 53.3% equity and 46.7% debt. Black Hills Power implemented interim rates on October 1, 2014, coinciding with Cheyenne Prairie's commercial operation date.

(d) On April 15, 2014, the IUB approved a capital investment recovery surcharge increase of $0.5 million.

(e) On April 29, 2014, Kansas Gas filed a rate request with the KCC to increase annual revenue to recover infrastructure and increased operating costs. On October 24, 2014, a settlement agreement was reached between Kansas Gas, the KCC, and intervenors to increase base rates by $5.2 million. A hearing is scheduled for November 12, 2014, and a final commission order is expected by January 6, 2015, with new rates effective by mid-January.

(f) On April 30, 2014 Colorado Electric filed a rate request with the CPUC to recover increased operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm, placed in service late 2012. The filing also seeks to implement a rider to recover a return on the construction costs for a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant. On October 28, 2014, an administrative law judge issued a recommended decision which incorporates a $2 million revenue increase, a 9.83% return on equity and a capital structure of approximately 49.8% equity and 50.2% debt. The recommended decision also approves the implementation of the rider. The recommended decision is subject to exceptions and final commission approval with rates effective by the end of 2014.

Non-regulated Energy Group

We report three segments within our Non-regulated Energy Group: Power Generation, Coal Mining and Oil and Gas.

Power Generation

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	Variance	2014	2013	Variance
	(in thousands)					
Revenue	$22,021	$21,968	$53	$66,349	$62,453	$3,896
Operations and maintenance	7,306	6,336	970	23,714	22,288	1,426
Depreciation and amortization	1,122	1,303	(181)	3,485	3,842	(357)
Total operating expense	8,428	7,639	789	27,199	26,130	1,069
Operating income	13,593	14,329	(736)	39,148	36,323	2,825
Interest expense, net	(920)	(2,846)	1,926	(2,782)	(8,226)	5,444
Other (expense) income, net	9	14	(5)	2	11	(9)
Income tax (expense) benefit	(4,853)	(4,790)	(63)	(13,272)	(10,726)	(2,546)
Net income (loss)	$7,829	$6,707	$1,122	$23,096	$17,382	$5,714

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

The following table summarizes MWh for our Power Generation segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Quantities Sold, Generated and Purchased (MWh)				
Sold				
Black Hills Colorado IPP	300,231	287,621	859,387	708,738
Black Hills Wyoming	151,435	152,919	430,420	429,921
Total Sold	451,666	440,540	1,289,807	1,138,659
Generated				
Black Hills Colorado IPP	300,231	287,621	859,387	708,738
Black Hills Wyoming	141,420	153,373	423,556	432,618
Total Generated	441,651	440,994	1,282,943	1,141,356
Purchased				
Black Hills Colorado IPP	—	—	—	—
Black Hills Wyoming	6,298	800	7,303	1,521
Total Purchased	6,298	800	7,303	1,521

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2014		2013		2014		2013	
Contracted power plant fleet availability:								
Coal-fired plant	96.1	%	100.0	%	98.0	%	98.0	%
Natural gas-fired plants	99.2	%	99.2	%	98.7	%	99.0	%
Total availability	98.5	%	99.4	%	98.6	%	98.8	%

Results of Operations for Power Generation for the Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013: Net income for the Power Generation segment was $7.8 million for the three months ended September 30, 2014, compared to Net income of $6.7 million for the same period in 2013 as a result of:

Revenue was comparable to the prior year reflecting an increase in megawatt hours delivered under PPAs, offset by a decrease in off-system sales from Wygen I.

Operations and maintenance increased primarily due to an increase in property taxes and repairs and maintenance at Colorado IPP, partially offset by a decrease in allocated corporate expenses.

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

Interest expense, net decreased primarily due to refinancing higher cost project debt and settling associated interest rate swaps in the fourth quarter of 2013.

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

Income tax (expense) benefit: The effective tax rate is lower in 2014 compared to 2013 due to a favorable current year true-up to the filed 2013 income tax return.

Results of Operations for Power Generation for the Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013: Net income for the Power Generation segment was $23 million for the nine months ended September 30, 2014, compared to Net income of $17 million for the same period in 2013 as a result of:

Revenue increased primarily due to an increase in megawatt hours delivered at higher prices, an increase in fired hours, favorable coal pricing under third party contracts, and an increase in off-system megawatt hour sales and pricing.

Operations and maintenance increased primarily due to increased outside services and materials for maintenance cycles, partially due to warranties expiring in the current year.

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

Interest expense, net decreased primarily due to refinancing higher cost project debt and settling associated interest rate swaps in the fourth quarter of 2013.

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

Income tax (expense) benefit: The effective tax rate is lower in 2014 compared to 2013 due to a favorable current year true-up to the filed 2013 income tax return.

Coal Mining

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	Variance	2014	2013	Variance
	(in thousands)					
Revenue	$15,573	$15,317	$256	$45,722	$43,218	$2,504
Operations and maintenance	9,875	10,163	(288)	30,029	29,565	464
Depreciation, depletion and amortization	2,542	2,914	(372)	7,802	8,743	(941)
Total operating expenses	12,417	13,077	(660)	37,831	38,308	(477)
Operating income (loss)	3,156	2,240	916	7,891	4,910	2,981
Interest (expense) income, net	(108)	(172)	64	(324)	(482)	158
Other income, net	535	550	(15)	1,727	1,744	(17)
Income tax benefit (expense)	(945)	(476)	(469)	(2,176)	(992)	(1,184)
Net income (loss)	$2,638	$2,142	$496	$7,118	$5,180	$1,938

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Tons of coal sold	1,082	1,133	3,232	3,265
Cubic yards of overburden moved	1,005	685	2,925	2,674

Revenue per ton	$14.38	$13.52	$14.15	$13.24

Results of Operations for Coal Mining for the Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013: Net income for the Coal Mining segment was $2.6 million for the three months ended September 30, 2014, compared to Net income of $2.1 million for the same period in 2013 as a result of:

Revenue increased primarily due to a 6% increase in price per ton sold, partially offset by a 5% decrease in tons sold. Pricing was favorably impacted by a coal contract price increase with the third-party operator of the Wyodak plant, partially offset by contract price adjustments based on actual mining costs. Tons of coal sold was negatively impacted by unplanned customer outages, and the closure of Neil Simpson 1. Approximately 50% of our coal production is sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operations and maintenance decreased primarily due to lower corporate allocated costs and a gain on the sale of land and equipment, partially offset by increased diesel consumption costs.

Depreciation, depletion and amortization decreased primarily due to lower depreciation on mine assets and mine reclamation asset retirement costs.

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

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

Income tax benefit (expense): The effective tax rate in 2014 is higher due to the reduced impact of the tax benefit of percentage depletion, and an unfavorable true-up to the filed 2013 income tax return.

Results of Operations for Coal Mining for the Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013: Net income for the Coal Mining segment was $7.1 million for the nine months ended September 30, 2014, compared to Net income of $5.2 million for the same period in 2013 as a result of:

Revenue increased primarily due to a 7% increase in price per ton sold and a 1% decrease in tons sold. Pricing was favorably impacted by a coal contract price increase with the third-party operator of the Wyodak plant. Approximately 50% of our coal production is sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operations and maintenance increased primarily due to materials and outside services on major maintenance projects, and increased diesel costs, partially offset by lower employee costs and a gain on the sale of land and equipment.

Depreciation, depletion and amortization decreased primarily due to lower depreciation on mine assets and mine reclamation asset retirement costs.

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

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

Income tax benefit (expense): The effective tax rate in 2014 is higher due to the reduced impact of the tax benefit of percentage depletion, and an unfavorable true-up to the filed 2013 income tax return.

Oil and Gas

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	Variance	2014	2013	Variance
	(in thousands)					
Revenue	$13,471	$14,426	$(955)	$43,469	$41,584	$1,885
Operations and maintenance	10,347	10,662	(315)	31,725	30,912	813
Depreciation, depletion and amortization	7,584	6,157	1,427	21,507	16,738	4,769
Total operating expenses	17,931	16,819	1,112	53,232	47,650	5,582
Operating income (loss)	(4,460)	(2,393)	(2,067)	(9,763)	(6,066)	(3,697)
Interest income (expense), net	(405)	(339)	(66)	(1,302)	(314)	(988)
Other income (expense), net	40	58	(18)	127	62	65
Income tax benefit (expense)	1,715	992	723	4,146	2,619	1,527
Net income (loss)	$(3,110)	$(1,682)	$(1,428)	$(6,792)	$(3,699)	$(3,093)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Production:				
Bbls of oil sold	82,640	84,260	249,130	246,367
Mcf of natural gas sold	1,856,138	1,765,622	5,456,928	5,282,961
Gallons of NGL sold	1,387,460	988,682	4,287,292	2,830,216
Mcf equivalent sales	2,550,187	2,412,422	7,564,179	7,165,479

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Average price received: (a)				
Oil/Bbl	$80.42	$94.32	$83.19	$92.60
Gas/Mcf	$2.70	$2.82	$3.07	$2.69
NGL/gallon	$0.85	$0.71	$0.92	$0.79
Depletion expense/Mcfe	$2.51	$2.16	$2.38	$1.92

(a) Net of hedge settlement gains and losses.

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

	Three Months Ended September 30, 2014				Three Months Ended September 30, 2013			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.42	$0.47	$0.53	$2.42	$1.39	$0.42	$0.44	$2.25
Piceance	0.46	0.45	0.30	1.21	0.70	0.47	0.50	1.67
Powder River	1.29	—	1.27	2.56	1.53	—	1.15	2.68
Williston	1.26	—	1.21	2.47	1.19	—	1.24	2.43
All other properties	1.91	—	0.54	2.45	1.08	—	0.69	1.77
Total weighted average	$1.21	$0.28	$0.66	$2.15	$1.26	$0.25	$0.70	$2.21

	Nine Months Ended September 30, 2014				Nine Months Ended September 30, 2013			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.45	$0.46	$0.59	$2.50	$1.36	$0.39	$0.46	$2.21
Piceance	0.22	0.30	0.41	0.93	0.72	0.54	0.36	1.62
Powder River	1.69	—	1.25	2.94	1.59	—	1.21	2.80
Williston	1.14	—	1.46	2.60	1.03	—	1.31	2.34
All other properties	1.65	—	0.43	2.08	0.81	—	0.18	0.99
Total weighted average	$1.16	$0.25	$0.70	$2.11	$1.22	$—	$0.63	$1.85

Results of Operations for Oil and Gas for the Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013: Net loss for the Oil and Gas segment was $3.1 million for the three months ended September 30, 2014, compared to Net loss of $1.7 million for the same period in 2013 as a result of:

Revenue decreased primarily due to a 15% decrease in the average hedged price received for crude oil sold, and a 4% decrease in the average hedged price received for natural gas sold, partially offset by a 6% production increase driven by two new Piceance Mancos Shale wells placed on production in the first quarter of 2014.

Operations and maintenance decreased primarily due to lower employee costs.

Depreciation, depletion and amortization increased primarily due to a higher depletion rate applied to greater production.

Interest income (expense), net was comparable to prior year.

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

Income tax (expense) benefit: Each period presented reflects a tax benefit. The tax benefit for 2014 was impacted by an unfavorable true-up to the filed 2013 income tax return.

Results of Operations for Oil and Gas for the Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013: Net loss for the Oil and Gas segment was $6.8 million for the nine months ended September 30, 2014, compared to Net loss of $3.7 million for the same period in 2013 as a result of:

Revenue increased primarily due to a 6% increase in volumes sold driven by increased gallons of NGL sales from production on the two new Mancos Shale wells placed on production in the first quarter of 2014, and a 14% increase in the average hedged price received for natural gas sold, partially offset by a 10% decrease in the average hedged price received for crude oil sold.

Operations and maintenance increased primarily due to higher production taxes and ad valorem taxes on higher natural gas revenue.

Depreciation, depletion and amortization increased primarily due to a higher depletion rate applied to greater production.

Interest income (expense), net increased primarily due to third-party interest received on non-operated well revenue in the prior year that offset 2013 interest expense.

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

Income tax (expense) benefit: Each period presented reflects a tax benefit. The tax benefit for 2014 was impacted by an unfavorable true-up to the filed 2013 income tax return.

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013: Net loss for Corporate was $0.3 million for the three months ended September 30, 2014, compared to Net income of $2.3 million for the three months ended September 30, 2013 as a result of:

- The settlement of the de-designated interest rate swaps in the fourth quarter of 2013, which resulted in no activity for the three months ended September 30, 2014, compared to the recognition of an unrealized, non-cash mark-to-market gain of $3.1 million during the three months ended September 30, 2013.

- The income for the three months ended September 30, 2014 included lower interest expense as compared to the three months ended September 30, 2013, as a result of lower interest rate debt from refinancing activities in fourth quarter 2013 and the settlement of the de-designated interest rate swaps.

- The three months ended September 30, 2014 included approximately a $1.3 million income tax benefit as a result of information received from the IRS related to the audit of the 2007 through 2009 tax years.

Results of Operations for Corporate activities for the Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013: Net loss for Corporate was $1.1 million for the nine months ended September 30, 2014, compared to Net income of $19.7 million for the nine months ended September 30, 2013 as a result of:

- The settlement of the de-designated interest rate swaps in the fourth quarter of 2013, which resulted in no activity for the nine months ended September 30, 2014, compared to the recognition of an unrealized, non-cash mark-to-market gain of $29.4 million during the nine months ended September 30, 2013.

- The income for the nine months ended September 30, 2014 included lower interest expense as compared to the nine months ended September 30, 2013, as a result of lower interest rate debt from refinancing activities in fourth quarter 2013 and the settlement of the de-designated interest rate swaps.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2013 Annual Report on Form 10-K filed with the SEC. For more information on our critical accounting policies, see Part II, Item 7 of our 2013 Annual Report on Form 10-K.

Liquidity and Capital Resources

OVERVIEW

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

The most significant items impacting cash are our capital expenditures, the purchase of natural gas for our Utilities Group and our Power Generation segment, and the payment of dividends to our shareholders. Generally, we experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, debt maturities, anticipated dividends, and anticipated capital expenditures discussed in this section.

Significant Factors Affecting Liquidity

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

Cash Flow Activities

The following table summarizes our cash flows for the nine months ended September 30, 2014 and 2013 (in thousands):

Cash provided by (used in):	2014	2013	Increase (Decrease)
Operating activities	$239,157	$251,766	$(12,609)
Investing activities	$(270,321)	$(236,639)	$(33,682)
Financing activities	$35,262	$(16,952)	$52,214

Year-to-Date 2014 Compared to Year-to-Date 2013

Operating Activities

Net cash provided by operating activities was $13 million lower for the nine months ended September 30, 2014, than for the same period in 2013 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $10 million higher for the nine months ended September 30, 2014 than for the same period in the prior year.

- Net outflows from operating assets and liabilities were $32 million for the nine months ended September 30, 2014, compared to net cash outflows of $7.5 million in the same period in the prior year. Changes are primarily due to:
    - Increased working capital requirements resulting from higher natural gas volumes sold during our peak winter heating season months driven by cold weather and higher natural gas prices creating an increase in fuel cost adjustments recorded in regulatory assets and an increase in natural gas held for distribution in our Utility Group; and
- Receipt in 2013 of approximately $8.4 million from a government grant relating to the Busch Ranch wind project.

Investing Activities

Net cash used in investing activities was $270 million for the nine months ended September 30, 2014, compared to net cash used in investing activities of $237 million for the same period in 2013 for a variance of $33 million. The variance was primarily driven by:

- Capital expenditures of approximately $290 million for the nine months ended September 30, 2014, compared to $239 million for the nine months ended September 30, 2013. The increase is related primarily to the construction of Cheyenne Prairie at our Electric Utilities segment, and capital expenditures at our Oil and Gas segment; and
- Proceeds of $22 million received on the sale of an operating asset in 2014 at our Power Generation segment.

Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2014, was $35 million, compared to net cash used in financing activities for the same period in 2013 of $17 million for a variance of $52 million. The variance was primarily driven by:

- Advancing funding for the redemption of $12 million of Black Hills Power’s pollution control revenue bonds on September 30, 2014;
- Net short-term borrowings under the revolving credit facility for the nine months ended September 30, 2014 increased primarily to fund additional working capital requirements due to colder weather during the peak winter heating season and the increase in overall capital expenditures; and
- The prior period reflected the refinancing of the $275 million term loan, proceeds from which replaced a short term loan of $150 million, a short term loan of $100 million, and $25 million used to pay off short-term borrowings under the Revolving Credit Facility.

Dividends

Dividends paid on our common stock totaled $52.2 million for the nine months ended September 30, 2014, or $1.17 per share. On October 28, 2014, our board of directors declared a quarterly dividend of $0.39 per share payable December 1, 2014, which is equivalent to an annual dividend rate of $1.56 per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our Revolving Credit Facility and our future business prospects.

Debt

Financing Transactions and Short-Term Liquidity

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

Revolving Credit Facility

On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from S&P and Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.125%, 1.125% and 1.125%, respectively, from May 29, 2014 through September 30, 2014; a reduction of 0.25% for each method of borrowing. A commitment fee is charged on the unused amount of the Revolving Credit Facility and is 0.175% based on our credit rating, a reduction of 0.025% compared to the prior arrangement.

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

Credit Facility	Expiration	Current Capacity	Borrowings at September 30, 2014	Letters of Credit at September 30, 2014	Available Capacity at September 30, 2014
Revolving Credit Facility	May 29, 2019	$500	$184	$32	$284

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintaining a certain recourse leverage ratio. Under the Revolving Credit Facility, our recourse leverage ratio is calculated by dividing the sum of our recourse debt, letters of credit, and certain guarantees issued, by total capital, which includes recourse indebtedness plus our net worth. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of September 30, 2014.

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

Hedges and Derivatives

Interest Rate Swaps

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. We have $75 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of approximately 2.25 years. These swaps have been designated as cash flow hedges for the Revolving Credit Facility, and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $6.7 million at September 30, 2014.

Financing Activities

On October 1, 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Black Hills Power issued $85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light issued $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. Proceeds from Black Hills Power’s bond sale also funded the early redemption of its 5.35% $12 million pollution control revenue bonds, originally due October 1, 2024.

On November 19, 2013, we entered into a $525 million, 4.25% senior unsecured note expiring on November 30, 2023. The proceeds of this debt were used to:

- Redeem our $250 million senior unsecured 9.0% notes originally due on May 15, 2014. This repayment occurred on December 19, 2013, for approximately $261 million which included a make-whole provision of approximately $8.5 million and accrued interest.

- Repay our variable interest rate Black Hills Wyoming project financing with a remaining balance of $87 million originally due on December 9, 2016, and settle the interest rate swaps designated to this project financing of $8.5 million.

- Settle the $250 million notional de-designated interest rate swaps for approximately $64 million.

- Pay down $55 million of the Revolving Credit Facility.

- Remainder was used for general corporate purposes.

On June 21, 2013, we entered into a new two-year $275 million term loan expiring on June 19, 2015. The proceeds from this new term loan repaid the $150 million term loan due on June 24, 2013, the $100 million long-term corporate term loan due on September 30, 2013, and $25 million in short-term borrowing under our Revolving Credit Facility. At September 30, 2014, the cost of borrowing under this new term loan was 1.3125% (LIBOR plus a margin of 1.125%).

Future Financing Plans

We anticipate the following financing activities:

- Evaluate alternatives for the $275 million term loan expiring on June 19, 2015.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Colorado, Iowa, Kansas, and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary’s liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. As of September 30, 2014, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $73 million. Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The only financial covenant under our Revolving Credit Facility is a recourse leverage ratio not to exceed 0.65 to 1.00. Additionally, covenants within Cheyenne Light’s financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of September 30, 2014, we were in compliance with this covenant.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2013 Annual Report on Form 10-K filed with the SEC.

Credit Ratings

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

The following table represents the credit ratings and outlook of BHC at September 30, 2014:

Rating Agency	Senior Unsecured Rating	Outlook

S&P	BBB	Stable
Moody’s(a)	Baa1	Stable
Fitch (b)	BBB+	Stable

(a) On January 30, 2014, Moody’s upgraded the BHC credit rating to Baa1 with a Stable outlook.

(b) On June 13, 2014, Fitch upgraded the BHC credit rating to BBB+ with a Stable outlook.

The following table represents the credit ratings of Black Hills Power's Senior Secured Mortgage Bonds at September 30, 2014:

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

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*On January 30, 2014, Moody's upgraded the BHP credit rating to A1 with a Stable outlook.

** On June 13, 2014, Fitch upgraded the BHP credit rating to A with a Stable outlook.

Capital Requirements

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

	Expenditures for the Nine Months Ended September 30, 2014[(a)]	Total 2014 Planned Expenditures [(b)]	Total 2015 Planned Expenditures	Total 2016 Planned Expenditures
Utilities:				
Electric Utilities	$168,819	$220,000	$215,000	$215,000
Gas Utilities	41,712	63,000	70,000	56,000
Non-regulated Energy:				
Power Generation	651	2,700	8,000	2,000
Coal Mining	5,247	6,600	7,000	6,000
Oil and Gas	63,402	117,800	123,000	122,000
Corporate	3,141	8,000	9,000	7,000
	$282,972	$418,100	$432,000	$408,000

(a) Expenditures for the nine months ended September 30, 2014 include the impact of accruals for property, plant and equipment.

(b) Includes actual expenditures for the nine months ended September 30, 2014.

We continue to evaluate potential future acquisitions and other growth opportunities that are dependent upon the availability of economic opportunities; as a result, capital expenditures may vary significantly from the estimates identified above.

Contractual Obligations

Except as noted below, there have been no significant changes in the contractual obligations from those previously disclosed in Note 18 of our Notes to the Consolidated Financial Statements in our 2013 Annual Report on Form 10-K.

Power Purchase Agreement

Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements, the most significant of which involves a 20-year economy energy PPA. The PPA contains a sharing arrangement where Black Hills Wyoming shares with the City of Gillette savings from wholesale power purchases made on behalf of the City when power costs are less than operating the generating unit. In addition, other ancillary agreements include agreements for Black Hills Wyoming to operate CTII, provide shared facilities, and provide generation dispatch services. Black Hills Wyoming's previous power sales agreement that sold all of CTII's output to Cheyenne Light expired on August 31, 2014.

Natural Gas Delivery Agreement

In 2012, we entered into a ten-year gas gathering and processing contract for natural gas production from our properties in the Piceance Basin in Colorado, under which we pay a gathering fee per Mcf. The contract requires us to deliver a minimum of 20,000 Mcf per day. This agreement became effective in first quarter of 2014 upon completion of the processing infrastructure capable of handling the committed volumes.

Construction Commitments

Construction was completed on Cheyenne Prairie, a 132 MW, $222 million natural gas-fired electric generating facility jointly owned by Cheyenne Light and Black Hills Power. The facility was placed into commercial operation on October 1, 2014. Included in the total cost of Cheyenne Prairie, are contingencies of approximately $2.5 million remaining on contracts pertaining to site finishing, contractor close-outs, and construction management demobilization and cleanup. Resolution of these contingencies is expected in the fourth quarter of 2014.

Guarantees

Except as noted below, there have been no significant changes to guarantees from those previously disclosed in Note 19 of the Notes to the Consolidated Financial Statements in our 2013 Annual Report on Form 10-K.

During the second quarter of 2014, guarantees of payment obligations arising from commodity transactions of BHUH for natural gas supply were reduced by $70 million and no longer exist, primarily due to improvement of the corporate credit rating, as well as the conversion of certain guarantees to letters of credit.

New Accounting Pronouncements

Other than the pronouncements reported in our 2013 Annual Report on Form 10-K filed with the SEC and those discussed in Note 1 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial position, results of operations, or cash flows.

FORWARD-LOOKING INFORMATION

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

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

Any forward-looking statement contained in this document speaks only as of the date on which the statement was made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement was made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements described in our 2013 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2013 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q and other reports that we file with the SEC from time to time.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

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

	September 30, 2014	December 31, 2013	September 30, 2013
Net derivative (liabilities) assets	$(4,650)	$(6,071)	$(8,396)
Cash collateral offset in Derivatives	4,650	6,733	8,396
Cash Collateral included in Other current assets	5,437	3,390	3,333
Net receivable (liability) position	$5,437	$4,052	$3,333

Oil and Gas Activities

We have entered into agreements to hedge a portion of our estimated 2014, 2015 and 2016 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at September 30, 2014, were as follows:

Natural Gas

	March 31,	June 30,	September 30,	December 31,	Total Year
2014					
Swaps - MMBtu				1,305,000	1,305,000
Weighted Average Price per MMBtu				$4.04	$4.04
2015					
Swaps - MMBtu	1,217,500	1,180,000	955,000	1,000,000	4,352,500
Weighted Average Price per MMBtu	$4.24	$4.03	$4.00	$4.04	$4.08
2016					
Swaps - MMBtu	587,500	572,500	567,500	545,000	2,272,500
Weighted Average Price per MMBtu	$3.91	$3.98	$4.08	$3.90	$3.97

Crude Oil

	March 31,	June 30,	September 30,	December 31,	Total Year
2014					
Swaps - Bbls				57,000	57,000
Weighted Average Price per Bbl				$90.66	$90.66
2015					
Swaps - Bbls	55,500	51,000	42,000	36,000	184,500
Weighted Average Price per Bbl	$89.98	$87.84	$88.18	$87.92	$88.58
2016					
Swaps - Bbls	39,000	39,000	36,000	36,000	150,000
Weighted Average Price per Bbl	$84.55	$84.55	$84.55	$84.55	$84.55

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. Further details of the swap agreements are set forth in Note 8 of the Notes to Consolidated Financial Statements in our 2013 Annual Report on Form 10-K and in Note 8 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	September 30, 2014	December 31, 2013	September 30, 2013	
	Designated Interest Rate Swaps [(a)]	Designated Interest Rate Swaps [(a)]	Designated Interest Rate Swaps [(b)]	De-designated Interest Rate Swaps [(c)]
Notional	$75,000	$75,000	$150,000	$ 250,000
Weighted average fixed interest rate	4.97 %	4.97 %	5.04 %	5.67 %
Maximum terms in years	2.25	3.00	3.25	0.25
Derivative liabilities, current	$3,397	$3,474	$7,039	$ 58,755
Derivative liabilities, non-current	$3,273	$5,614	$11,388	$ —
Pre-tax accumulated other comprehensive income (loss)	$(6,670)	$(9,088)	$(18,427)	$ —
Cash collateral receivable (payable) included in derivatives	$—	$—	$—	$ 5,960

(a) These swaps are designated to borrowings on our Revolving Credit Facility, and are priced using three-month LIBOR, matching the floating portion of the related debt.

(b) At September 30, 2013, $75 million of these interest rate swaps were designated to borrowings on our Revolving Credit Facility and $75 million were designated to borrowings on our project financing debt at Black Hills Wyoming. These swaps were priced using three-month LIBOR, matching the floating portion of the related swaps. The portion of the swaps that were designated to Black Hills Wyoming was settled during the fourth quarter of 2013 upon repayment of the Black Hills Wyoming project financing.

(c) These swaps were settled during the fourth quarter of 2013.

Based on September 30, 2014 market interest rates and balances related to our interest rate swaps, a loss of approximately $3.4 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Estimated and actual realized gains or losses will change during future periods as market interest rates change.

ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) as of September 30, 2014. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

During the quarter ended September 30, 2014, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 18 in Item 8 of our 2013 Annual Report on Form 10-K and Note 14 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 14 is incorporated by reference into this item.

ITEM 1A. Risk Factors

Except as noted below, there are no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2013 Annual Report on Form 10-K.

ENVIRONMENTAL RISKS

Federal and state laws concerning greenhouse gas regulations and air emissions may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain.

We own and operate regulated and non-regulated fossil-fuel generating plants in South Dakota, Wyoming, and Colorado. Recent developments under federal and state laws and regulations governing air emissions from fossil-fuel generating plants will likely result in more stringent emission limitations, which could have a material impact on our costs of operations. In addition to the environmental matters identified in Item 1A of our Annual Report on Form 10-K under the caption “Environmental Matters”, the following recently proposed regulations could negatively impact our operations.

On June 2, 2014, the EPA proposed the Clean Power Plan to cut carbon emissions from existing electric generating units. The design of the Clean Power Plan is to decrease existing coal-fired generation, and increase the utilization of existing gas generation, increase renewable energy, and demand side management. This rule could have a significant impact on our coal and natural gas generating fleet. The rule calls for states to develop plans to meet their assigned emission rate targets by 2030. The rule also allows states to formulate a regional approach whereby they would join with other states and be assigned a new single target for the group. We are currently evaluating this proposal, but cannot predict the impact on operations as this rule is expected to be final in June 2015, and state plans are expected to be due at the earliest in June 2016, with extensions possible to 2017 and 2018. We expect any impact to us to be mitigated through the recent Osage, Ben French, Neil Simpson I and W.N. Clark plant closures.

The Clean Power Plan could have a significant impact on our WRDC coal mine. Coal competes with other energy sources, such as natural gas, wind, solar and hydropower. If the Clean Power Plan Rule regulations were to have an adverse effect on coal as a domestic energy source, this rule could have a significant impact on our coal mining operations.

New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, and the closure of certain generating facilities. To the extent our regulated fossil-fuel generating plants are included in rate base we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the power generated by those non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.

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

There were no unregistered securities sold during the nine months ended September 30, 2014.

ITEM 4. Mine Safety Disclosures

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

ITEM 5. Other Information

None.

ITEM 6. Exhibits

Exhibit Number	Description
Exhibit 3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant’s Form 10-K for 2004).
Exhibit 3.2*	Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant’s Form 8-K filed on February 3, 2010).
Exhibit 4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant’s Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant’s Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant’s Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant’s Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant’s Form 8-K filed on November 18, 2013).
Exhibit 4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant’s Post-Effective Amendment No. 1 to the Registrant’s Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant’s Post-Effective Amendment No. 1 to the Registrant’s Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant’s Post-Effective Amendment No. 2 to the Registrant’s Registration Statement on Form S-3 (No. 333-150669)).
Exhibit 4.3*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant’s Form 10-K for 2000).

Exhibit 10.1*	Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on October 2, 2014).
Exhibit 10.2*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant’s Form 8-K filed on October 2, 2014).
Exhibit 10.3*	First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant’s Form 8-K filed on October 2, 2014).

Exhibit 10.4*	Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 95	Mine Safety and Health Administration Safety Data.
Exhibit 101	Financial Statements for XBRL Format.

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*Previously filed as part of the filing indicated and incorporated by reference herein.

SIGNATURES

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

BLACK HILLS CORPORATION

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

/s/ Anthony S. Cleberg
Anthony S. Cleberg, Executive Vice President and
Chief Financial Officer

Dated: November 4, 2014

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