BLACK HILLS CORP /SD/
Form 10-Q
August 06, 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 June 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 July 31, 2014	
Common stock, $1.00 par value	44,641,421	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 currently being constructed in Cheyenne, Wyoming by Cheyenne Light and Black Hills Power. Construction is expected to be completed for this 132 megawatt facility in 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.
Conflict Minerals	As defined by Dodd-Frank, conflict minerals are cassiterite, columbite-tantalite, gold and wolframite that are mined in the Democratic Republic of the Congo or surrounding countries
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.
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
GCA	Gas Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of gas and certain services through to customers.

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
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.
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited)	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands, except per share amounts)			
Revenue	$283,237	$279,826	$743,406	$660,497
Operating expenses:				
Utilities -				
Fuel, purchased power and cost of natural gas sold	101,331	99,172	331,799	267,345
Operations and maintenance	66,074	64,977	137,301	130,667
Non-regulated energy operations and maintenance	21,350	20,890	43,682	42,219
Depreciation, depletion and amortization	36,712	35,152	72,795	69,933
Taxes - property, production and severance	11,044	10,069	21,380	20,449
Other operating expenses	149	529	274	1,001
Total operating expenses	236,660	230,789	607,231	531,614
Operating income	46,577	49,037	136,175	128,883
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(17,886)	(23,369)	(35,746)	(47,041)
Allowance for funds used during construction - borrowed	256	411	526	484
Capitalized interest	246	272	503	538
Unrealized gain (loss) on interest rate swaps, net	—	18,793	—	26,249
Interest income	576	475	966	760
Allowance for funds used during construction - equity	293	42	531	242
Other income (expense), net	409	473	1,000	879
Total other income (expense), net	(16,106)	(2,903)	(32,220)	(17,889)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	30,471	46,134	103,955	110,994
Equity in earnings (loss) of unconsolidated subsidiaries	—	—	—	(86)
Income tax benefit (expense)	(10,651)	(15,616)	(36,017)	(37,193)
Net income (loss) available for common stock	$19,820	$30,518	$67,938	$73,715
Earnings (loss) per share of common stock:				
Earnings (loss) per share, Basic -				
Total income (loss) per share, Basic	$0.45	$0.69	$1.53	$1.67
Earnings (loss) per share, Diluted -				
Total income (loss) per share, Diluted	$0.44	$0.69	$1.52	$1.66
Weighted average common shares outstanding:				
Basic	44,399	44,172	44,365	44,113

Diluted	44,588	44,412	44,571	44,363
Dividends paid per share of common stock	$0.39	$0.38	$0.78	$0.76

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

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

(unaudited)	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			
Net income (loss) available for common stock	$19,820	$30,518	$67,938	$73,715
Other comprehensive income (loss), net of tax:				
Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of $1,115 and $(2,174) for the three months ended 2014 and 2013 and $2,422 and $(1,057) for the six months ended 2014 and 2013, respectively)	(1,959)	3,878	(4,216)	2,217
Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $(774) and $(647) for the three months ended 2014 and 2013 and $(1,199) and $(883) for the six months ended 2014 and 2013, respectively)	1,403	1,201	2,183	1,669
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 six months ended 2014 and 2013, respectively)	—	—	(2)	—
Benefit plan liability tax adjustments - net gain (loss)	(394)	—	(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 six months ended 2014 and 2013, respectively)	—	—	164	—
Reclassification adjustments of benefit plan liability - prior service cost (net of tax of $39 and $(268) for the three months ended 2014 and 2013 and $43 and $(251) for the six months ended 2014 and 2013, respectively)	(70)	364	(79)	318
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax of $(91) and $0 for the three months ended 2014 and 2013 and $(176) and $(192) for the six months ended 2014 and 2013, respectively)	168	—	325	503
Other comprehensive income (loss), net of tax	(852)	5,443	(2,019)	4,707
Comprehensive income (loss) available for common stock	$18,968	$35,961	$65,919	$78,422

See Note 11 for additional disclosures.

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

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BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of June 30, 2014	December 31, 2013	June 30, 2013
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$14,697	$7,841	$30,633
Restricted cash and equivalents	2	2	7,279
Accounts receivable, net	135,145	177,573	132,726
Materials, supplies and fuel	81,164	88,478	73,768
Derivative assets, current	1,737	717	903
Income tax receivable, net	1,043	1,460	146
Deferred income tax assets, net, current	23,872	18,889	38,764
Regulatory assets, current	64,735	24,451	26,258
Other current assets	21,660	25,877	27,595
Total current assets	344,055	345,288	338,072
Investments	17,096	16,697	16,566
Property, plant and equipment	4,408,291	4,259,445	4,066,502
Less: accumulated depreciation and depletion	(1,325,660)	(1,269,148)	(1,234,578)
Total property, plant and equipment, net	3,082,631	2,990,297	2,831,924
Other assets:			
Goodwill	353,396	353,396	353,396
Intangible assets, net	3,286	3,397	3,508
Regulatory assets, non-current	138,226	138,197	180,646
Other assets, non-current	31,808	27,906	22,402
Total other assets, non-current	526,716	522,896	559,952
TOTAL ASSETS	$3,970,498	$3,875,178	$3,746,514

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

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

	As of		
	June 30, 2014	December 31, 2013	June 30, 2013
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$100,098	$130,416	$88,071
Accrued liabilities	141,177	151,277	135,819
Derivative liabilities, current	3,480	3,474	69,270
Regulatory liabilities, current	828	10,727	20,550
Notes payable	132,700	82,500	100,000
Current maturities of long-term debt	275,000	—	255,507
Total current liabilities	653,283	378,394	669,217
Long-term debt, net of current maturities	1,121,950	1,396,948	958,559
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	476,059	432,287	387,674
Derivative liabilities, non-current	4,251	5,614	12,384
Regulatory liabilities, non-current	119,462	109,429	129,013
Benefit plan liabilities	116,403	111,479	177,216
Other deferred credits and other liabilities	137,765	133,279	129,763
Total deferred credits and other liabilities	853,940	792,088	836,050
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 44,682,885; 44,550,239; and 44,516,472 shares, respectively	44,683	44,550	44,517
Additional paid-in capital	744,505	742,344	737,729
Retained earnings	573,379	540,244	532,810
Treasury stock, at cost – 40,951; 50,877; and 42,480 shares, respectively	(1,801)	(1,968)	(1,587)
Accumulated other comprehensive income (loss)	(19,441)	(17,422)	(30,781)
Total stockholders' equity	1,341,325	1,307,748	1,282,688
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,970,498	$3,875,178	$3,746,514

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

	Six Months Ended June 30,	
	2014	2013
Operating activities:	(in thousands)	
Net income (loss) available for common stock	$67,938	$73,715
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	72,795	69,933
Deferred financing cost amortization	1,107	2,188
Derivative fair value adjustments	(1,660)	4,248
Stock compensation	6,908	6,896
Unrealized (gain) loss on interest rate swaps, net	—	(26,249)
Deferred income taxes	35,514	36,607
Employee benefit plans	7,409	11,096
Other adjustments, net	1,481	8,967
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	7,314	8,940
Accounts receivable, unbilled revenues and other operating assets	(5,851)	28,377
Accounts payable and other operating liabilities	(24,978)	(26,739)
Other operating activities, net	5,858	(594)
Net cash provided by (used in) operating activities	173,835	197,385
Investing activities:		
Property, plant and equipment additions	(177,302)	(147,230)
Other investing activities	(2,994)	2,006
Net cash provided by (used in) investing activities	(180,296)	(145,224)
Financing activities:		
Dividends paid on common stock	(34,803)	(33,774)
Common stock issued	1,693	2,570
Short-term borrowings - issuances	214,100	133,300
Short-term borrowings - repayments	(163,900)	(310,300)
Long-term debt - issuances	—	275,000
Long-term debt - repayments	—	(103,786)
Other financing activities	(3,773)	—
Net cash provided by (used in) financing activities	13,317	(36,990)
Net change in cash and cash equivalents	6,856	15,171
Cash and cash equivalents, beginning of period	7,841	15,462
Cash and cash equivalents, end of period	$14,697	$30,633

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 June 30, 2014, December 31, 2013, and June 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 six months ended June 30, 2014 and June 30, 2013, and our financial condition as of June 30, 2014, December 31, 2013, and June 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 June 30, 2014	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$158,740	$3,144	$11,427
Gas	102,499	—	1,994
Non-regulated Energy:			
Power Generation	1,267	20,713	7,194
Coal Mining	5,583	9,068	2,016
Oil and Gas	15,148	—	(1,660)
Corporate activities	—	—	(1,151)
Inter-company eliminations	—	(32,925)	—
Total	$283,237	$—	$19,820

Three Months Ended June 30, 2013	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$154,338	$3,694	$10,610
Gas	105,836	—	3,192
Non-regulated Energy:			
Power Generation	1,031	19,094	5,031
Coal Mining	6,807	7,511	1,973
Oil and Gas	11,814	—	(1,964)
Corporate activities [(a)]	—	—	11,679
Inter-company eliminations	—	(30,299)	(3)
Total	$279,826	$—	$30,518

Six Months Ended June 30, 2014	External Operating Revenues	Intercompany Operating Revenues	Net Income (Loss)
Utilities:			
Electric	$336,835	$7,151	$26,002
Gas	361,836	—	26,692
Non-regulated Energy:			
Power Generation	2,536	41,792	15,267
Coal Mining	12,201	17,948	4,480
Oil and Gas	29,998	—	(3,682)
Corporate activities	—	—	(821)
Inter-company eliminations	—	(66,891)	—
Total	$743,406	$—	$67,938

Six Months Ended June 30, 2013	External Operating Revenues	Intercompany Operating Revenues	Net Income (Loss)
Utilities:			
Electric	$312,821	$7,841	$22,966
Gas	305,648	—	21,675
Non-regulated Energy:			
Power Generation	2,053	38,432	10,675
Coal Mining	12,817	15,084	3,038
Oil and Gas	27,158	—	(2,017)
Corporate activities [(a)]	—	—	17,378
Inter-company eliminations	—	(61,357)	—
Total	$660,497	$—	$73,715

(a) Corporate activities include a $12 million and a $17 million after-tax non-cash mark-to-market gain for the three and six months ended June 30, 2013, respectively on certain interest rate swaps.

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

Total Assets (net of inter-company eliminations) as of:	June 30, 2014	December 31, 2013	June 30, 2013
Utilities:			
Electric [(a)]	$2,603,900	$2,525,947	$2,417,952
Gas	799,365	805,617	734,337
Non-regulated Energy:			
Power Generation [(a)]	85,269	95,692	108,515
Coal Mining	73,701	78,825	82,553
Oil and Gas	307,837	288,366	256,855
Corporate activities	100,426	80,731	146,302
Total assets	$3,970,498	$3,875,178	$3,746,514

(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:

June 30, 2014	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$48,333	$21,716	$(622)	$69,427
Gas Utilities	43,104	9,265	(1,027)	51,342
Power Generation	1,388	—	—	1,388
Coal Mining	1,866	—	—	1,866
Oil and Gas	9,123	—	(13)	9,110
Corporate	2,012	—	—	2,012
Total	$105,826	$30,981	$(1,662)	$135,145

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

June 30, 2013	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$45,250	$24,290	$(630)	$68,910
Gas Utilities	38,749	13,192	(1,074)	50,867
Power Generation	157	—	—	157
Coal Mining	2,503	—	—	2,503
Oil and Gas	8,373	—	(19)	8,354
Corporate	1,935	—	—	1,935
Total	$96,967	$37,482	$(1,723)	$132,726

(4) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of June 30, 2014	As of December 31, 2013	As of June 30, 2013
Regulatory assets				
Deferred energy and fuel cost adjustments - current [(a)(d)]	1	$29,605	$16,775	$15,951
Deferred gas cost adjustments and natural gas price derivatives [(a)(d)]	7	39,040	12,366	13,090
AFUDC [(b)]	45	12,468	12,315	12,456
Employee benefit plans [(c)]	13	65,874	67,059	115,379
Environmental [(a)]	subject to approval	1,314	1,800	1,798
Asset retirement obligations [(a)]	44	3,278	3,266	3,257
Bond issue cost [(a)]	24	3,347	3,419	3,489
Renewable energy standard adjustment [(a)]	5	14,501	14,186	14,694
Flow through accounting [(c)]	35	22,754	20,916	17,995
Other regulatory assets [(a)]	15	10,780	10,546	8,795
		$202,961	$162,648	$206,904
Regulatory liabilities				
Deferred energy and gas costs [(a)]	1	$6,490	$11,708	$22,340
Employee benefit plans [(c)]	13	34,356	34,431	60,214
Cost of removal [(a)]	44	70,841	64,970	59,461
Other regulatory liabilities [(c)]	25	8,603	9,047	7,548
		$120,290	$120,156	$149,563

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

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

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

	June 30, 2014	December 31, 2013	June 30, 2013
Materials and supplies	$51,925	$50,196	$51,334
Fuel - Electric Utilities	7,679	6,213	6,817
Natural gas in storage held for distribution	21,560	32,069	15,617

Total materials, supplies and fuel	$81,164	$88,478	$73,768

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(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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income (loss) available for common stock	$19,820	$30,518	$67,938	$73,715
Weighted average shares - basic	44,399	44,172	44,365	44,113
Dilutive effect of:				
Equity compensation	189	240	206	250
Weighted average shares - diluted	44,588	44,412	44,571	44,363

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Equity compensation	81	28	63	34
Anti-dilutive shares	81	28	63	34

(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:

	June 30, 2014		December 31, 2013		June 30, 2013	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$132,700	$20,272	$82,500	$22,100	$100,000	$43,157

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 June 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 June 30, 2014, our Corporate term loan due June 19, 2015, for $275 million has been re-classified to Current maturities of long-term debt from Long-term debt, net of current maturities.

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 June 30, 2014	Covenant Requirement	
Recourse Leverage Ratio	54%	Less than	65%

As of June 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 June 30, 2014, our credit exposure included a $0.5 million exposure to a non-investment grade energy marketing company. 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.

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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:

	June 30, 2014		December 31, 2013		June 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)]	424,500	9,265,000	412,500	7,082,500	520,500	10,712,500
Maximum terms in months [(b)]	1	1	3	1	6	1
Derivative assets, current	$—	$—	$55	$—	$610	$293
Derivative assets, non-current	$—	$—	$—	$—	$—	$—
Derivative liabilities, current	$—	$—	$—	$—	$130	$276
Derivative liabilities, non-current	$—	$—	$—	$—	$—	$—

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

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

A $3.4 million loss is included in AOCI at June 30, 2014, and would be realized over the next 12 months if market prices remained equal to June 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:

	June 30, 2014		December 31, 2013		June 30, 2013	
	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)
Natural gas futures purchased	16,240,000	78	17,930,000	84	13,330,000	77
Natural gas options purchased	3,980,000	9	3,890,000	8	2,850,000	5
Natural gas basis swaps purchased	13,415,000	66	14,785,000	60	10,650,000	66

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

	June 30, 2014	December 31, 2013	June 30, 2013
Derivative assets, current	$1,737	$662	$—
Derivative assets, non-current	$—	$—	$—
Derivative liabilities, non-current	$—	$—	$—
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$3,561	$7,567	$8,450

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:

	June 30, 2014	December 31, 2013	June 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	2.5	3.0	3.5	0.5
Derivative liabilities, current	$3,480	$3,474	$6,965	$61,899
Derivative liabilities, non-current	$4,251	$5,614	$12,384	$—

(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.
At June 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.

(b) These swaps are priced using three-month LIBOR, matching the floating portion of the related debt. The portion of the swaps that were designated to Black Hills Wyoming were 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 June 30, 2014, market interest rates and balances related to our interest rate swaps, a loss of approximately $3.5 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months.

Estimated and actual realized gains or losses will change during future periods as market interest rates change.

Cash Flow Hedges

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

Three Months Ended June 30, 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	$(337)	Interest expense	$(926)		$—
Commodity derivatives	(2,737)	Revenue	(1,251)		—
Total	$(3,074)		$(2,177)		$—

Three Months Ended June 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	$1,067	Interest expense	$(1,820)		$—
Commodity derivatives	4,985	Revenue	(28)		—
Total	$6,052		$(1,848)		$—

Six Months Ended June 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	$(429)	Interest expense	$(1,820)		$—
Commodity derivatives	(6,209)	Revenue	(1,562)		—
Total	$(6,638)		$(3,382)		$—

Six Months Ended June 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	$1,048	Interest expense	$(3,616)	$—
Commodity derivatives	2,226	Revenue	1,064	—
Total	$3,274		$(2,552)	$—

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(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 June 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	—	—	—	—	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	600	—	(600)	—
Commodity derivatives — Utilities	—	4,342	—	(2,605)	1,737
Total	$—	$4,942	$—	$(3,205)	$1,737
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	4,020	—	(4,020)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	2,030	—	(2,030)	—
Commodity derivatives — Utilities	—	5,989	—	(5,989)	—
Interest rate swaps	—	7,731	—	—	7,731
Total	$—	$19,770	$—	$(12,039)	$7,731

	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 June 30, 2013				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$45	$—	$(6)	$39
Basis Swaps -- Oil	—	1,109	—	(538)	571
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	1,882	—	(1,589)	293
Commodity derivatives — Utilities	—	1,378	—	(1,378)	—
Total	$—	$4,414	$—	$(3,511)	$903
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$181	$—	$(98)	$83
Basis Swaps -- Oil	—	350	—	(303)	47
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	445	—	(169)	276
Commodity derivatives — Utilities	—	8,581	—	(8,581)	—
Interest rate swaps	—	87,208	—	(5,960)	81,248
Total	$—	$96,765	$—	$(15,111)	$81,654

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Fair Value Measures by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis 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 June 30, 2014, December 31, 2013, and June 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 June 30, 2014

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$262	$—
Commodity derivatives	Derivative assets — non-current	338	—
Commodity derivatives	Derivative liabilities — current	—	3,702
Commodity derivatives	Derivative liabilities — non-current	—	2,348
Interest rate swaps	Derivative liabilities — current	—	3,480
Interest rate swaps	Derivative liabilities — non-current	—	4,251
Total derivatives designated as hedges		$600	$13,781
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$1,737	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	3,384
Total derivatives not designated as hedges		$1,737	$3,384

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 June 30, 2013

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$1,225	$—
Commodity derivatives	Derivative assets — non-current	1,651	—
Commodity derivatives	Derivative liabilities — current	—	889
Commodity derivatives	Derivative liabilities — non-current	—	41
Interest rate swaps	Derivative liabilities — current	—	6,965
Interest rate swaps	Derivative liabilities — non-current	—	12,384
Total derivatives designated as hedges		$2,876	$20,279
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$160	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	1,884
Commodity derivatives	Derivative liabilities — non-current	—	5,365
Interest rate swaps	Derivative liabilities — current	—	67,859
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives not designated as hedges		$160	$75,108

(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:

	June 30, 2014		December 31, 2013		June 30, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$14,697	$14,697	$7,841	$7,841	$30,633	$30,633
Restricted cash and equivalents [(a)]	$2	$2	$2	$2	$7,279	$7,279
Notes payable [(a)]	$132,700	$132,700	$82,500	$82,500	$100,000	$100,000
Long-term debt, including current maturities [(b)]	$1,396,950	$1,578,756	$1,396,948	$1,491,422	$1,214,066	$1,323,543

(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		Six Months Ended	
		June 30, 2014	June 30, 2013	June 30, 2014	June 30, 2013
Gains (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$926	$1,820	$1,820	$3,616
Commodity contracts	Revenue	1,251	28	1,562	(1,064)
		2,177	1,848	3,382	2,552
Income tax	Income tax benefit (expense)	(774)	(647)	(1,199)	(883)
Reclassification adjustments related to cash flow hedges, net of tax		$1,403	$1,201	$2,183	$1,669
Amortization of defined benefit plans:					
Prior service cost	Utilities - Operations and maintenance	$(25)	$(31)	$(51)	$(62)
	Non-regulated energy operations and maintenance	(84)	(32)	(71)	(64)
Actuarial gain (loss)		158	421	315	842

	Utilities - Operations and maintenance				
	Non-regulated energy operations and maintenance	101	274	186	548
		150	632	379	1,264
Income tax	Income tax benefit (expense)	(52)	(268)	(133)	(443)
Reclassification adjustments related to defined benefit plans, net of tax		$98	$364	$246	$821

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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)
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)

(12) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Six months ended	June 30, 2014	June 30, 2013
	(in thousands)	
Non-cash investing and financing activities from continuing operations—		
Property, plant and equipment acquired with accrued liabilities	$40,611	$45,000
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)	$(35,009)	$(44,191)
Income taxes, net	$(396)	$(5,406)

(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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Service cost	$1,362	$1,608	$2,724	$3,216
Interest cost	3,963	3,825	7,926	7,650
Expected return on plan assets	(4,516)	(4,654)	(9,032)	(9,308)
Prior service cost	16	16	32	32
Net loss (gain)	1,201	3,062	2,403	6,124
Net periodic benefit cost	$2,026	$3,857	$4,053	$7,714

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Service cost	$425	$419	$850	$838
Interest cost	480	417	959	834
Expected return on plan assets	(21)	(20)	(42)	(40)
Prior service cost (benefit)	(107)	(125)	(214)	(250)
Net loss (gain)	40	121	80	242
Net periodic benefit cost	$817	$812	$1,633	$1,624

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Service cost	$374	$348	$749	$696
Interest cost	362	332	724	664
Prior service cost	1	1	1	2
Net loss (gain)	124	198	249	396
Net periodic benefit cost	$861	$879	$1,723	$1,758

Contributions

We anticipate that we will make contributions to the benefit plans during 2014 and 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 Three Months Ended June 30, 2014	Contributions Made Six Months Ended June 30, 2014	Additional Contributions Anticipated for 2014	Contributions Anticipated for 2015
Defined Benefit Pension Plans	$—	$—	$—	$2,806
Non-pension Defined Benefit Postretirement Healthcare Plans	$956	$1,912	$1,912	$3,822
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$373	$746	$746	$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.

Bond Purchase Agreements

On June 30, 2014, Black Hills Power and Cheyenne Light entered into agreements to issue $160 million of first mortgage bonds to finance Cheyenne Prairie. Black Hills Power will issue $85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light will issue $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. The closing for the sale of the first mortgage bonds for both utilities is anticipated to be October 1, 2014, subject to satisfaction of customary closing conditions.

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. We believe that our reserves dedicated to the gathering system, and the projected volumes are adequate to materially satisfy our delivery commitments under this agreement.

Turbine Sale Agreement

On May 6, 2013, Black Hills Wyoming entered into an agreement to sell its 40 MW CTII natural-gas fired generating unit to the City of Gillette, Wyoming for approximately $22 million, upon expiration of the PPA with Cheyenne Light in August 2014. As part of the sale, Black Hills Wyoming will provide services to the City of Gillette through an economy energy PPA. The sale received FERC approval on July 14, 2014, and is expected to close by August 31, 2014.

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 of Cheyenne Prairie, a 132 MW natural gas-fired electric generating facility jointly owned by Cheyenne Light and Black Hills Power is expected to cost approximately $222 million. Construction is expected to be completed by September 30, 2014. As of June 30, 2014, committed contracts for equipment purchases and for construction were 100% and 98% complete, respectively.

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 June 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 June 30, 2014, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at June 30, 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 June 30, 2014, the restricted net assets at our Utilities Group were approximately $141 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 June 30, 2014	Expiration
Indemnification for subsidiary reclamation/surety bonds [(1)]	$65,744	Ongoing

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(1) 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, 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.

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 six months ended June 30, 2014 and 2013, and our financial condition as of June 30, 2014, December 31, 2013 and June 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 59.

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 June 30, 2014 Compared to Three Months Ended June 30, 2013. Net income (loss) for the three months ended June 30, 2014 was $20 million, or $0.44 per share, compared to Net income (loss) of $31 million, or $0.69 per share, reported for the same period in 2013.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. Net income (loss) for the six months ended June 30, 2014 was $68 million, or $1.52 per share, compared to Net income (loss) of $74 million, or $1.66 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 June 30,			Six Months Ended June 30,		
	2014	2013	Variance	2014	2013	Variance
Revenue						
Utilities	$264,383	$263,868	$515	$705,822	$626,310	$79,512
Non-regulated Energy	51,779	46,257	5,522	104,475	95,544	8,931
Inter-company eliminations	(32,925)	(30,299)	(2,626)	(66,891)	(61,357)	(5,534)
	$283,237	$279,826	$3,411	$743,406	$660,497	$82,909
Net income (loss)						
Electric Utilities	$11,427	$10,610	$817	$26,002	$22,966	$3,036
Gas Utilities	1,994	3,192	(1,198)	26,692	21,675	5,017
Utilities	13,421	13,802	(381)	52,694	44,641	8,053
Power Generation	7,194	5,031	2,163	15,267	10,675	4,592
Coal Mining	2,016	1,973	43	4,480	3,038	1,442
Oil and Gas	(1,660)	(1,964)	304	(3,682)	(2,017)	(1,665)
Non-regulated Energy	7,550	5,040	2,510	16,065	11,696	4,369
Corporate activities and eliminations (a)	(1,151)	11,676	(12,827)	(821)	17,378	(18,199)
Net income (loss)	$19,820	$30,518	$(10,698)	$67,938	$73,715	$(5,777)

(a) Corporate activities for the three and six months ended June 30, 2013 include a $12 million and a $17 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 milder weather during the three months ended June 30, 2014 resulting in a 16% decrease in heating degree days compared to the same period in 2013. Year-to-date results were favorably impacted by colder weather during the first quarter of 2014. Heating degree days were 2% higher for the six months ended June 30, 2014, compared to the same period in 2013. Heating degree days for the three and six months ended June 30, 2014 were 5% and 12% higher than normal, respectively, compared to 24% and 9% higher than normal for the same periods in 2013.

- Construction continued on Cheyenne Prairie, a natural gas-fired electric generating facility to serve Cheyenne Light and Black Hills Power customers. The 132 MW generation project is expected to cost approximately $222 million, exclusive of construction financing costs which are being recovered through construction financing riders. The Electric Utilities recorded additional gross margins of approximately $3.7 million and $7.8 million, respectively, for the three and six months ended June 30, 2014, related to these riders. To date, we have expended approximately $196 million. The project is expected to be completed at or less than budget and is on schedule to be placed into service in October 2014.

- 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 June 30, 2014, Black Hills Power and Cheyenne Light entered into agreements to issue $160 million of first mortgage bonds to finance Cheyenne Prairie. Black Hills Power will issue $85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light will issue $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. The closing for the sale of the first mortgage bonds for both utilities is anticipated to be October 1, 2014, subject to satisfaction of customary closing conditions.

- 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 other 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 for an annual revenue increase of $8.0 million to recover operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm. Colorado Electric seeks approval of a new rider pursuant to the Clean Air-Clean Jobs Act Adjustment, to recover a return on the expenditures associated with the construction of a $65 million natural gas-fired combustion turbine unit, previously approved by the CPUC to replace the W.N. Clark retirement. The filing seeks a return on equity of 10.3% and a capital structure of approximately 50.5% equity and 49.5% debt. A subsequent filing on June 27, 2014 reduced our request to $7.2 million to reflect updated cost information.

- On April 29, 2014, Kansas Gas filed a rate request with the KCC to increase annual revenue by $7.3 million primarily to recover infrastructure and increased operating costs. The filing seeks a return on equity of 10.6%, and a capital structure of approximately 50.3% equity and 49.7% debt.

- 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.

- 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 will largely be 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.

- On January 17, 2014, Black Hills Power filed a rate request with the WPSC for an annual revenue increase of $2.8 million to recover investments made in electric infrastructure, 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.

- Our Utilities Group continued its efforts to acquire small municipal gas distribution systems adjacent to our existing service territories. During the first quarter of 2014, we acquired an additional gas system, adding approximately 70 customers, and we announced the pending acquisition of assets serving approximately 400 customers.

Non-regulated Energy Group

- Oil and Gas production volumes increased 15% and 5%, respectively, for the three and six months ended June 30, 2014. The average hedged price received increased for natural gas by 35% and 24% and decreased for oil by 18% and 8%, respectively for the three and six months ended June 30, 2014 compared to the same periods in 2013.

- On July 14, 2014, Black Hills Wyoming received FERC approval for the sale of its 40 MW CTII natural gas-fired unit to the City of Gillette, Wyoming for approximately $22 million. The sale is expected to close on August 31, 2014 upon expiration of the PPA with Cheyenne Light.

- Drilling commenced in June 2014 in the southern Piceance Basin on two of the six horizontal Mancos Shale wells planned for 2014.

- Production continued from the two horizontal Mancos Shale wells placed on production during the first quarter of 2014. 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 our corporate credit rating to Baa1 from Baa2 with continued stable outlook.

- Consolidated interest expense decreased by approximately $5.5 million and $11 million for the three and six months ended June 30, 2014, respectively, compared to the three and six months ended June 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 electric operations of Black Hills Power, Colorado Electric and the 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 June 30,			Six Months Ended June 30,		
	2014	2013	Variance	2014	2013	Variance
	(in thousands)					
Revenue — electric	$154,544	$151,775	$2,769	$322,909	$302,148	$20,761
Revenue — gas	7,340	6,257	1,083	21,077	18,514	2,563
Total revenue	161,884	158,032	3,852	343,986	320,662	23,324
Fuel, purchased power and cost of gas — electric	69,723	67,349	2,374	148,142	133,038	15,104
Purchased gas — gas	4,051	2,515	1,536	12,325	8,953	3,372
Total fuel, purchased power and cost of gas	73,774	69,864	3,910	160,467	141,991	18,476
Gross margin — electric	84,821	84,426	395	174,767	169,110	5,657
Gross margin — gas	3,289	3,742	(453)	8,752	9,561	(809)
Total gross margin	88,110	88,168	(58)	183,519	178,671	4,848
Operations and maintenance	40,272	39,383	889	82,872	78,218	4,654
Depreciation and amortization	19,274	19,665	(391)	38,361	38,826	(465)
Total operating expenses	59,546	59,048	498	121,233	117,044	4,189

Operating income	28,564	29,120	(556)	62,286	61,627	659
Interest expense, net	(11,829)	(13,810)	1,981	(23,841)	(28,207)	4,366
Other income (expense), net	352	173	179	608	458	150
Income tax benefit (expense)	(5,660)	(4,873)	(787)	(13,051)	(10,912)	(2,139)
Net income (loss)	$11,427	$10,610	$817	$26,002	$22,966	$3,036

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	Three Months Ended June 30,		Six Months Ended June 30,	
Revenue - Electric (in thousands)	2014	2013	2014	2013
Residential:				
Black Hills Power	$14,332	$13,535	$34,392	$29,977
Cheyenne Light	8,167	8,307	17,840	17,637
Colorado Electric	21,316	21,829	45,995	45,950
Total Residential	43,815	43,671	98,227	93,564
Commercial:				
Black Hills Power	21,200	18,913	42,728	36,397
Cheyenne Light	15,238	14,476	29,631	27,243
Colorado Electric	23,101	21,663	44,991	42,814
Total Commercial	59,539	55,052	117,350	106,454
Industrial:				
Black Hills Power	7,534	7,210	14,869	13,220
Cheyenne Light	7,304	5,344	14,528	10,199
Colorado Electric	9,535	9,647	18,573	19,284
Total Industrial	24,373	22,201	47,970	42,703
Municipal:				
Black Hills Power	846	847	1,638	1,561
Cheyenne Light	514	490	968	948
Colorado Electric	3,277	3,492	6,584	6,039
Total Municipal	4,637	4,829	9,190	8,548
Total Retail Revenue - Electric	132,364	125,753	272,737	251,269
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	4,473	4,926	10,071	10,693
Off-system Wholesale:				
Black Hills Power	5,411	7,849	14,486	14,099
Cheyenne Light	1,787	2,094	4,174	4,776
Colorado Electric	1,912	2,133	3,995	3,240
Total Off-system Wholesale	9,110	12,076	22,655	22,115
Other Revenue:				
Black Hills Power	6,945	7,552	13,823	14,702
Cheyenne Light	534	482	1,287	1,048
Colorado Electric	1,118	986	2,336	2,321
Total Other Revenue	8,597	9,020	17,446	18,071
Total Revenue - Electric	$154,544	$151,775	$322,909	$302,148

Quantities Generated and Purchased (in MWh)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Generated —				
Coal-fired:				
Black Hills Power [(a)]	336,842	450,097	754,090	877,112
Cheyenne Light	162,847	155,384	332,636	327,696
Colorado Electric	—	—	—	—
Total Coal-fired	499,689	605,481	1,086,726	1,204,808
Natural Gas and Oil:				
Black Hills Power	2,665	4,558	4,972	7,678
Cheyenne Light	—	—	—	—
Colorado Electric [(b)]	40,599	107,535	58,668	138,589
Total Natural Gas and Oil	43,264	112,093	63,640	146,267
Wind:				
Colorado Electric	13,230	11,834	27,558	23,007
Total Wind	13,230	11,834	27,558	23,007
Total Generated:				
Black Hills Power	339,507	454,655	759,062	884,790
Cheyenne Light	162,847	155,384	332,636	327,696
Colorado Electric	53,829	119,369	86,226	161,596
Total Generated	556,183	729,408	1,177,924	1,374,082
Purchased —				
Black Hills Power	365,463	349,183	796,265	737,382
Cheyenne Light	197,225	205,027	404,543	406,872
Colorado Electric [(b)]	467,197	412,037	937,299	867,175
Total Purchased	1,029,885	966,247	2,138,107	2,011,429
Total Generated and Purchased:				
Black Hills Power	704,970	803,838	1,555,327	1,622,172
Cheyenne Light	360,072	360,411	737,179	734,568
Colorado Electric	521,026	531,406	1,023,525	1,028,771
Total Generated and Purchased	1,586,068	1,695,655	3,316,031	3,385,511

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

(b) Decrease reflects a current year unplanned outage 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 six months ended June 30 2013.

	Three Months Ended June 30,		Six Months Ended June 30,	
Quantity (in MWh)	2014	2013	2014	2013
Residential:				
Black Hills Power	107,394	113,525	278,704	274,495
Cheyenne Light	57,328	60,669	127,983	136,125
Colorado Electric	132,256	140,755	285,887	296,191
Total Residential	296,978	314,949	692,574	706,811
Commercial:				
Black Hills Power	176,541	174,763	360,989	350,380
Cheyenne Light	129,688	132,214	256,100	261,643
Colorado Electric	174,239	180,340	332,418	351,045
Total Commercial	480,468	487,317	949,507	963,068
Industrial:				
Black Hills Power	104,914	105,856	205,765	197,488
Cheyenne Light	94,861	65,716	185,586	135,668
Colorado Electric	111,090	92,867	201,207	171,416
Total Industrial	310,865	264,439	592,558	504,572
Municipal:				
Black Hills Power	7,709	8,147	15,394	15,930
Cheyenne Light	2,131	2,143	4,624	4,738
Colorado Electric	31,385	29,049	58,073	47,095
Total Municipal	41,225	39,339	78,091	67,763
Total Retail Quantity Sold	1,129,536	1,106,044	2,312,730	2,242,214
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	71,999	77,653	167,227	181,437
Off-system Wholesale:				
Black Hills Power	169,498	277,840	424,294	516,287
Cheyenne Light	42,250	61,514	94,606	131,822
Colorado Electric	50,178	38,238	80,924	70,015
Total Off-system Wholesale	261,926	377,592	599,824	718,124
Total Quantity Sold:				
Black Hills Power	638,055	757,784	1,452,373	1,536,017
Cheyenne Light	326,258	322,256	668,899	669,996
Colorado Electric	499,148	481,249	958,509	935,762
Total Quantity Sold	1,463,461	1,561,289	3,079,781	3,141,775
Other Uses, Losses or Generation, net [(a)]:				
Black Hills Power	66,915	46,054	102,954	86,155
Cheyenne Light	33,814	38,155	68,280	64,572
Colorado Electric	21,878	50,157	65,016	93,009
Total Other Uses, Losses and Generation, net	122,607	134,366	236,250	243,736

Total Energy	1,586,068	1,695,655	3,316,031	3,385,511

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

Degree Days	Three Months Ended June 30, 2014		2013	
	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Heating Degree Days:				
Black Hills Power	1,025	2 %	1,227	43 %
Cheyenne Light	1,191	— %	1,321	11 %
Colorado Electric	633	4 %	752	(1)%
Combined	877	2 %	1,026	19 %
Cooling Degree Days:				
Black Hills Power	99	(7)%	78	(27)%
Cheyenne Light	50	(2)%	123	141 %
Colorado Electric	209	(8)%	376	66 %
Combined	140	(7)%	225	48 %

Degree Days	Six Months Ended June 30, 2014		2013	
	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Heating Degree Days:				
Black Hills Power	4,435	5 %	4,437	9 %
Cheyenne Light	4,397	4 %	4,483	6 %
Colorado Electric	3,303	3 %	3,502	4 %
Combined	3,905	4 %	4,012	6 %
Cooling Degree Days:				
Black Hills Power	99	(7)%	78	(27)%
Cheyenne Light	50	(2)%	123	141 %
Colorado Electric	209	(9)%	376	66 %
Combined	140	(7)%	225	49 %

Electric Utilities Power Plant Availability	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Coal-fired plants [(a)]	84.8 %	96.0 %	90.1 %	96.4 %
Other plants [(b)(c)]	89.9 %	95.5 %	84.0 %	97.1 %
Total availability	87.7 %	95.7 %	86.6 %	96.7 %

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

(b) The three months and six months ended June 30, 2014 include a planned outage at Ben French CT's #1 and #2 for a controls upgrade.

(c) The six months ended June 30, 2014, reflects an unplanned outage due to a turbine bearing replacement and combustor upgrade at Pueblo Airport Generation 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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenue - Natural Gas (in thousands):				
Residential	$4,519	$4,033	$12,743	$11,565
Commercial	1,975	1,522	5,951	5,130
Industrial	616	505	1,903	1,403
Other Sales Revenue	230	197	480	416
Total Revenue - Natural Gas	$7,340	$6,257	$21,077	$18,514
Gross Margin (in thousands):				
Residential	$2,383	$2,674	$5,987	$6,634
Commercial	631	748	1,962	2,240
Industrial	47	123	323	271
Other Gross Margin	228	197	480	416
Total Gross Margin	$3,289	$3,742	$8,752	$9,561
Volumes Sold (Dth):				
Residential	450,715	492,261	1,485,892	1,585,261
Commercial	284,493	278,914	848,887	904,851
Industrial	120,558	137,212	376,485	364,159
Total Volumes Sold	855,766	908,387	2,711,264	2,854,271

Results of Operations for the Electric Utilities for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net income for the Electric Utilities was $11 million for the three months ended June 30, 2014, compared to $11 million for the three months ended June 30, 2013, as a result of:

Gross margin was comparable to the prior year, reflecting increased rider margins of $2.2 million due to a return on additional investment in our generating facilities. Industrial megawatt hours sold increased 18% compared to the same period in the prior year, primarily driven by load growth at Cheyenne Light. These increases were offset by a 38% decrease in cooling degree days compared to the same period in the prior year resulting in a $1.6 million decrease on lower residential and commercial megawatt hours sold, and a $0.6 million decrease in wholesale power volumes as a result of plant outages. Our Cheyenne Light gas utility experienced an 11% decrease in heating degree days, primarily from April, resulting in a $0.5 million decrease in retail natural gas sales.

Operations and maintenance increased primarily due to increases in employee costs, regulatory support, and property taxes.

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 higher in 2014 primarily due to the research and development tax credit not being extended to 2014.

Results of Operations for the Electric Utilities for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net income for the Electric Utilities was $26 million for the six months ended June 30, 2014, compared to $23 million for the six months ended June 30, 2013, as a result of:

Gross margin increased primarily due to a return on additional investments which increased base electric margins by $4.0 million and increased rider margins by $5.8 million. Industrial megawatt hours sold increased by approximately 18 percent, primarily due to load growth at Cheyenne Light. These increases are partially offset by a $1.8 million decrease from lower residential and commercial megawatt hours sold driven by a 38% decrease in cooling degree days compared to the same period in the prior year, a $1.0 million decrease in wholesale volumes sold, a $0.9 million decrease from the TCA, and a $0.5 million decrease from a construction savings incentive recognized in the prior year. 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, regulatory support 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 higher in 2014 primarily due to the research and development tax credit not being extended to 2014. The prior year reflected the entire year of the 2012 research and development tax credit due to retroactive reinstatement of the credit in January 2013 by the U.S. Congress.

Gas Utilities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Variance	2014	2013	Variance
	(in thousands)					
Natural gas — regulated	$95,350	$98,635	$(3,285)	$346,582	$290,586	$55,996
Other — non-regulated services	7,149	7,201	(52)	15,254	15,062	192
Total revenue	102,499	105,836	(3,337)	361,836	305,648	56,188
Natural gas — regulated	52,266	53,143	(877)	223,040	173,523	49,517
Other — non-regulated services	3,675	3,517	158	7,397	7,234	163
Total cost of sales	55,941	56,660	(719)	230,437	180,757	49,680
Gross margin	46,558	49,176	(2,618)	131,399	124,891	6,508
Operations and maintenance	33,454	31,852	1,602	68,832	65,078	3,754
Depreciation and amortization	6,538	6,583	(45)	13,059	13,086	(27)
Total operating expenses	39,992	38,435	1,557	81,891	78,164	3,727
Operating income (loss)	6,566	10,741	(4,175)	49,508	46,727	2,781
Interest expense, net	(3,722)	(5,907)	2,185	(7,574)	(12,184)	4,610
Other income (expense), net	19	(5)	24	1	7	(6)
Income tax benefit (expense)	(869)	(1,637)	768	(15,243)	(12,875)	(2,368)
Net income (loss)	$1,994	$3,192	$(1,198)	$26,692	$21,675	$5,017

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Revenue (in thousands)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Residential:				
Colorado	$9,435	$9,850	$33,122	$29,644
Nebraska	17,519	22,932	80,411	71,784
Iowa	22,052	18,139	76,816	56,890
Kansas	10,348	12,620	43,625	38,385
Total Residential	59,354	63,541	233,974	196,703
Commercial:				
Colorado	2,060	1,778	6,757	5,438
Nebraska	4,590	7,098	24,656	23,345
Iowa	11,202	8,442	37,116	26,217
Kansas	3,624	4,052	15,295	12,841
Total Commercial	21,476	21,370	83,824	67,841
Industrial:				
Colorado	504	507	581	555
Nebraska	99	100	307	305
Iowa	1,141	709	2,313	1,454
Kansas	5,632	6,068	6,718	7,000
Total Industrial	7,376	7,384	9,919	9,314
Transportation:				
Colorado	217	227	542	628
Nebraska	2,542	2,395	8,272	7,111
Iowa	983	999	2,744	2,538
Kansas	1,563	1,453	4,056	3,502
Total Transportation	5,305	5,074	15,614	13,779
Other Sales Revenue:				
Colorado	36	22	67	(52)
Nebraska	651	626	1,354	1,240
Iowa	262	190	414	302
Kansas	890	428	1,416	1,459
Total Other Sales Revenue	1,839	1,266	3,251	2,949
Total Regulated Revenue	95,350	98,635	346,582	290,586
Non-regulated Services	7,149	7,201	15,254	15,062
Total Revenue	$102,499	$105,836	$361,836	$305,648

Gross Margin (in thousands)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Residential:				
Colorado	$3,597	$3,884	$9,969	$10,122
Nebraska	9,925	11,055	30,814	29,366
Iowa	8,993	9,397	24,203	22,986
Kansas	6,529	6,925	18,113	17,129
Total Residential	29,044	31,261	83,099	79,603
Commercial:				
Colorado	607	579	1,667	1,568
Nebraska	1,772	2,292	6,935	6,927
Iowa	2,300	2,592	7,525	7,044
Kansas	1,495	1,519	4,678	4,163
Total Commercial	6,174	6,982	20,805	19,702
Industrial:				
Colorado	130	158	160	188
Nebraska	33	31	101	85
Iowa	61	81	146	163
Kansas	696	750	932	974
Total Industrial	920	1,020	1,339	1,410
Transportation:				
Colorado	216	227	542	628
Nebraska	2,541	2,395	8,272	7,111
Iowa	982	999	2,743	2,538
Kansas	1,563	1,453	4,056	3,502
Total Transportation	5,302	5,074	15,613	13,779
Other Sales Margins:				
Colorado	37	22	68	(52)
Nebraska	653	626	1,356	1,240
Iowa	263	190	414	302
Kansas	692	318	849	1,079
Total Other Sales Margins	1,645	1,156	2,687	2,569
Total Regulated Gross Margin	43,085	45,493	123,543	117,063
Non-regulated Services	3,473	3,683	7,856	7,828
Total Gross Margin	$46,558	$49,176	$131,399	$124,891

Distribution Quantities Sold and Transportation (in Dth)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Residential:				
Colorado	1,018,966	1,268,892	4,040,400	4,190,227
Nebraska	1,278,283	2,056,892	8,264,576	7,794,565
Iowa	1,249,921	1,732,786	7,892,965	7,023,152
Kansas	715,890	1,044,593	4,597,445	4,260,899
Total Residential	4,263,060	6,103,163	24,795,386	23,268,843
Commercial:				
Colorado	255,312	256,317	891,002	832,593
Nebraska	485,023	836,828	2,960,179	3,035,626
Iowa	884,997	1,164,878	4,370,689	3,970,551
Kansas	391,548	474,953	1,933,515	1,752,087
Total Commercial	2,016,880	2,732,976	10,155,385	9,590,857
Industrial:				
Colorado	101,468	127,124	111,793	136,861
Nebraska	12,168	13,585	39,133	44,265
Iowa	119,710	129,772	313,573	272,096
Kansas	1,084,608	1,222,845	1,264,695	1,411,666
Total Industrial	1,317,954	1,493,326	1,729,194	1,864,888
Wholesale and Other:				
Kansas	32,274	19,199	100,907	74,209
Total Wholesale and Other	32,274	19,199	100,907	74,209
Total Distribution Quantities Sold	7,630,168	10,348,664	36,780,872	34,798,797
Transportation:				
Colorado	209,799	216,333	540,143	629,042
Nebraska	6,623,555	6,040,006	16,586,774	14,722,321
Iowa	4,319,339	4,790,583	10,476,705	10,469,740
Kansas	3,594,159	3,336,618	8,421,296	7,388,636
Total Transportation	14,746,852	14,383,540	36,024,918	33,209,739
Total Distribution Quantities Sold and Transportation	22,377,020	24,732,204	72,805,790	68,008,536

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

	Three Months Ended June 30,			
	2014		2013	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Colorado	924	— %	972	5 %
Nebraska	580	1 %	769	33 %
Iowa	775	11 %	873	27 %
Kansas [(a)]	480	7 %	636	42 %
Combined [(b)]	711	5 %	842	24 %

	Six Months Ended June 30,			
	2014		2013	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Colorado	3,783	2 %	3,844	4 %
Nebraska	3,852	6 %	3,898	8 %
Iowa	4,949	18 %	4,616	14 %
Kansas [(a)]	3,169	8 %	3,186	9 %
Combined [(b)]	4,235	12 %	4,148	9 %

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(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 June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net income for the Gas Utilities was $2.0 million for the three months ended June 30, 2014, compared to Net income of $3.2 million for the three months ended June 30, 2013, as a result of:

Gross margin decreased primarily due to milder weather compared to the same period in the prior year resulting in lower residential and commercial volumes sold. Heating degree days were 16% lower for the three months ended June 30, 2014, compared to the same period in the prior year and 5% higher than normal.

Operations and maintenance increased primarily due to an increase in employee costs.

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 was slightly lower than 2013 due primarily to an increase in an estimated flow-through tax adjustment.

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Results of Operations for the Gas Utilities for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net income for the Gas Utilities was $26.7 million for the six months ended June 30, 2014, compared to Net income of $21.7 million for the six months ended June 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 2% higher for the six months ended June 30, 2014, compared to the same period in the prior year and 12% higher than normal.

Operations and maintenance increased primarily due to an increase in employee costs 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 was slightly lower than 2013 due primarily to 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	pending	$2.8	pending
Black Hills Power (c)	Electric	3/2014	pending	$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	$7.2	pending

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(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 the natural gas-fired facility.

(b) On January 17, 2014, Black Hills Power filed a rate request with the WPSC for an annual revenue increase of $2.8 million to recover investments made in electric infrastructure, 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 is seeking to implement the new rates on October 1, 2014, to coincide with Cheyenne Prairie's expected in-service date.

(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 is seeking to implement the new rates on October 1, 2014, to coincide with Cheyenne Prairie's expected in-service 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 by $7.3 million primarily to recover infrastructure and increased operating costs. The filing seeks a return on equity of 10.6%, and a capital structure of approximately 50.3% equity and 49.7% debt.

(f) On April 30, 2014, Colorado Electric filed a rate request with the CPUC for an annual revenue increase of $8.0 million to recover operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm. Colorado Electric seeks approval of a new rider pursuant to the Clean Air-Clean Jobs Act Adjustment, to recover a return on the expenditures associated with the construction of a $65 million natural gas-fired combustion turbine unit, previously approved by the CPUC to replace the W.N. Clark retirement. The filing seeks a return on equity of 10.3% and a capital structure of approximately 50.5% equity and 49.5% debt. A subsequent filing on June 27, 2014 reduced our request to $7.2 million to reflect updated cost information.

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 June 30,			Six Months Ended June 30,		
	2014	2013	Variance	2014	2013	Variance
	(in thousands)					
Revenue	$21,980	$20,125	$1,855	$44,328	$40,485	$3,843
Operations and maintenance	8,733	8,161	572	16,410	15,952	458
Depreciation and amortization	1,154	1,313	(159)	2,363	2,539	(176)
Total operating expense	9,887	9,474	413	18,773	18,491	282
Operating income	12,093	10,651	1,442	25,555	21,994	3,561
Interest expense, net	(934)	(2,706)	1,772	(1,862)	(5,380)	3,518
Other (expense) income, net	2	(4)	6	(7)	(3)	(4)
Income tax (expense) benefit	(3,967)	(2,910)	(1,057)	(8,419)	(5,936)	(2,483)
Net income (loss)	$7,194	$5,031	$2,163	$15,267	$10,675	$4,592

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Quantities Sold, Generated and Purchased (MWh)	(in thousands)			
Sold				
Black Hills Colorado IPP	273,200	186,921	559,156	421,117
Black Hills Wyoming	138,377	134,896	278,985	277,002
Total Sold	411,577	321,817	838,141	698,119
Generated				
Black Hills Colorado IPP	273,200	186,921	559,156	421,117
Black Hills Wyoming	141,458	135,056	282,136	279,245
Total Generated	414,658	321,977	841,292	700,362
Purchased				
Black Hills Colorado IPP	—	—	—	—
Black Hills Wyoming	16	721	1,005	721
Total Purchased	16	721	1,005	721

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Contracted power plant fleet availability:				
Coal-fired plant	98.7 %	94.0 %	99.0 %	97.0 %
Natural gas-fired plants	99.2 %	99.2 %	98.5 %	98.9 %
Total availability	99.1 %	98.0 %	98.6 %	98.5 %

Results of Operations for Power Generation for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net income for the Power Generation segment was $7.2 million for the three months ended June 30, 2014, compared to Net income of $5.0 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 and an increase in megawatt hours sold and pricing for off-system sales at Black Hills Wyoming.

Operations and maintenance increased primarily due to repairs and maintenance at Colorado IPP.

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 comparable to the same period in the prior year.

Results of Operations for Power Generation for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net income for the Power Generation segment was $15.3 million for the six months ended June 30, 2014, compared to Net income of $10.7 million for the same period in 2013 as a result of:

Revenue increased primarily due to an increase in megawatts delivered at higher prices, an increase in fired hours and an increase in off-system megawatt hour sales and pricing at Black Hills Wyoming.

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

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

Interest expense, net decreased 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 comparable to the same period in the prior year.

Coal Mining

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Variance	2014	2013	Variance
	(in thousands)					
Revenue	$14,651	$14,318	$333	$30,149	$27,901	$2,248
Operations and maintenance	10,023	9,251	772	20,154	19,402	752
Depreciation, depletion and amortization	2,570	2,964	(394)	5,260	5,829	(569)
Total operating expenses	12,593	12,215	378	25,414	25,231	183
Operating income (loss)	2,058	2,103	(45)	4,735	2,670	2,065
Interest (expense) income, net	(113)	(179)	66	(216)	(310)	94
Other income, net	589	581	8	1,192	1,194	(2)
Income tax benefit (expense)	(518)	(532)	14	(1,231)	(516)	(715)
Net income (loss)	$2,016	$1,973	$43	$4,480	$3,038	$1,442

The following table provides certain operating statistics for our Coal Mining segment (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Tons of coal sold	1,063	1,079	2,150	2,132
Cubic yards of overburden moved	1,010	930	1,920	1,989
Revenue per ton	$13.79	$13.27	$14.03	$13.09

Results of Operations for Coal Mining for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net income for the Coal Mining segment was $2.0 million for the three months ended June 30, 2014, compared to Net income of $2.0 million for the same period in 2013 as a result of:

Revenue increased primarily due to a 4% increase in price per ton sold, partially offset by a 1% decrease in tons sold. 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 for major maintenance projects.

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 is comparable to the same period in the prior year.

Results of Operations for Coal Mining for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net income for the Coal Mining segment was $4.5 million for the six months ended June 30, 2014, compared to Net income of $3.0 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% increase in tons sold. 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, partially offset by lower overburden removal costs, lower employee costs, and a favorable coal tax adjustment of $0.7 million.

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 increase in the effective tax rate in 2014 is due primarily to the reduced impact of the tax benefit of percentage depletion.

Oil and Gas

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Variance	2014	2013	Variance
	(in thousands)					
Revenue	$15,148	$11,814	$3,334	$29,998	$27,158	$2,840
Operations and maintenance	10,239	9,995	244	21,378	20,250	1,128
Depreciation, depletion and amortization	7,290	5,214	2,076	13,923	10,581	3,342
Total operating expenses	17,529	15,209	2,320	35,301	30,831	4,470
Operating income (loss)	(2,381)	(3,395)	1,014	(5,303)	(3,673)	(1,630)
Interest income (expense), net	(442)	(54)	(388)	(897)	25	(922)
Other income (expense), net	49	81	(32)	87	4	83
Income tax benefit (expense)	1,114	1,404	(290)	2,431	1,627	804
Net income (loss)	$(1,660)	$(1,964)	$304	$(3,682)	$(2,017)	$(1,665)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Production:				
Bbls of oil sold	92,228	65,304	166,490	162,107
Mcf of natural gas sold	1,840,826	1,784,389	3,600,790	3,517,339
Gallons of NGL sold	1,764,111	895,720	2,899,832	1,841,534
Mcf equivalent sales	2,646,210	2,304,173	5,013,992	4,753,057

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Average price received: [(a)]				
Oil/Bbl	$78.18	$95.15	$84.56	$91.71
Gas/Mcf	$3.17	$2.35	$3.25	$2.63
NGL/gallon	$0.80	$0.73	$0.95	$0.84
Depletion expense/Mcfe	$2.36	$1.82	$2.31	$1.80

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(a) Net of hedge settlement gains and losses.

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

	Three Months Ended June 30, 2014				Three Months Ended June 30, 2013			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.39	$0.46	$0.59	$2.44	$1.39	$0.40	$0.52	$2.31
Piceance	0.26	0.23	0.35	0.84	0.80	0.52	0.27	1.59
Powder River	1.55	—	1.15	2.70	2.00	—	1.23	3.23
Williston	1.31	—	1.41	2.72	1.43	—	2.52	3.95
All other properties	1.30	—	0.77	2.07	0.65	—	(0.48)	0.17
Total weighted average	$1.08	$0.23	$0.72	$2.03	$1.32	$0.27	$0.55	$2.14

	Six Months Ended June 30, 2014				Six Months Ended June 30, 2013			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.46	$0.45	$0.61	$2.52	$1.34	$0.37	$0.47	$2.18
Piceance	0.11	0.23	0.45	0.79	0.73	0.58	0.30	1.61
Powder River	1.90	—	1.23	3.13	1.62	—	1.24	2.86
Williston	1.08	—	1.59	2.67	0.94	—	1.34	2.28
All other properties	1.47	—	0.36	1.83	0.67	—	(0.08)	0.59
Total weighted average	$1.13	$0.23	$0.73	$2.09	$1.19	$0.25	$0.60	$2.04

Results of Operations for Oil and Gas for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net loss for the Oil and Gas segment was $1.7 million for the three months ended June 30, 2014, compared to Net loss of $2.0 million for the same period in 2013 as a result of:

Revenue increased primarily due to a 15% increase in volumes sold driven by production from two new Piceance Mancos Shale wells and an increase in non-operated Bakken crude oil volumes sold, and a 35% increase in the average hedged price received for natural gas sold. These increases were partially offset by an 18% decrease in the average price received for crude oil sold.

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

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: The effective tax rate is higher in 2014 primarily due to the research and development tax credit not being extended to 2014.

Results of Operations for Oil and Gas for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net loss for the Oil and Gas segment was $3.7 million for the six months ended June 30, 2014, compared to Net loss of $2.0 million for the same period in 2013 as a result of:

Revenue increased primarily due to a 5% increase in volumes sold driven by increased gallons of NGL sales from production on the two new Mancos Shale wells, and a 24% increase in the average hedged price received for natural gas sold, partially offset by an 8% decrease in the average price received for crude oil sold.

Operations and maintenance increased primarily due to higher non-operated well costs, 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 interest received on third-party non-operated well revenue in the prior year that offset interest expense.

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

Income tax (expense) benefit: The effective tax rate is higher in 2014 primarily due to the research and development tax credit not being extended to 2014. The prior year reflected the entire year of the 2012 research and development tax credit due to retroactive reinstatement of the credit in January 2013 by the U.S. Congress.

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013: Net loss for Corporate was $1.2 million for the three months ended June 30, 2014, compared to Net income of $11.7 million for the three months ended June 30, 2013 as a result of:

- The settlement of the de-designated interest rate swaps in the fourth quarter of 2013, resulted in no activity for the three months ended June 30, 2014, compared to the recognition of an unrealized, non-cash mark-to-market gain of $18.8 million during the three months ended June 30, 2013.

- The income for the three months ended June 30, 2014 included lower interest expense as compared to the three months ended June 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.

Results of Operations for Corporate activities for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013: Net loss for Corporate was $0.8 million for the six months ended June 30, 2014, compared to Net income of $17.4 million for the six months ended June 30, 2013 as a result of:

- The settlement of the de-designated interest rate swaps in the fourth quarter of 2013, resulted in no activity for the six months ended June 30, 2014, compared to the recognition of an unrealized, non-cash mark-to-market gain of $26.2 million during the six months ended June 30, 2013.

- The income for the six months ended June 30, 2014 included lower interest expense as compared to the six months ended June 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 six months ended June 30, 2014 and 2013 (in thousands):

Cash provided by (used in):	2014	2013	Increase (Decrease)
Operating activities	$173,835	$197,385	$(23,550)
Investing activities	$(180,296)	$(145,224)	$(35,072)
Financing activities	$13,317	$(36,990)	$50,307

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

Operating Activities

Net cash provided by operating activities was $24 million lower for the six months ended June 30, 2014, than for the same period in 2013 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $4.1 million higher for the six months ended June 30, 2014 than for the same period in the prior year.

- Net outflows from operating assets and liabilities were $24 million for the six months ended June 30, 2014, compared to net cash outflows of $11 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 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 $180 million for the six months ended June 30, 2014, compared to net cash used in investing activities of $145 million for the same period in 2013 for a variance of $35 million. The variance was primarily driven by:

- Capital expenditures of approximately $177 million for the six months ended June 30, 2014, compared to $147 million for the six months ended June 30, 2013. The increase is related primarily to the construction of Cheyenne Prairie at our Electric Utilities segment.

Financing Activities

Net cash provided by financing activities for the six months ended June 30, 2014, was $13.3 million, compared to net cash used in financing activities for the same period in 2013 of $37 million for a variance of $50 million. The variance was primarily driven by:

- Net short-term borrowings under the revolving credit facility for the six months ended June 30, 2014 were used primarily to fund additional working capital requirements due to colder weather during the peak winter heating season and the increase in overall capital expenditures. The prior period reflected the refinancing of the $275 million term loan, proceeds of 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 $34.8 million for the six months ended June 30, 2014, or $0.78 per share. On July 30, 2014, our board of directors declared a quarterly dividend of $0.39 per share payable September 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 June 30, 2014; a reduction of 0.250% 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 June 30, 2014	Letters of Credit at June 30, 2014	Available Capacity at June 30, 2014
Revolving Credit Facility	May 29, 2019	$500	$133	$20	$347

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 June 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 2.5 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 $7.7 million at June 30, 2014.

Financing Activities

On June 30, 2014, Black Hills Power and Cheyenne Light entered into Bond Purchase Agreements, to authorize the sale of $160 million of first mortgage bonds in a private placement to finance Cheyenne Prairie. Black Hills Power will issue $85 million of 4.43% first mortgage bonds due October 20, 2044. Cheyenne Light will issue $75 million of 4.53% first mortgage bonds due October 20, 2044. The closing date for the sale of the first mortgage bonds for both utilities is anticipated to be October 1, 2014, subject to satisfaction of customary closing conditions.

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 June 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:

- Closing on the delayed-draw private placement bonds Black Hills Power and Cheyenne Light executed on June 30, 2014 to finance Cheyenne Prairie. It’s anticipated that Black Hills Power and Cheyenne Light will execute the draw of $85 million and $75 million, respectively, on October 1, 2014; and

- Evaluate options 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 ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. As of June 30, 2014, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $141 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 June 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 June 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 June 30, 2014:

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

*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 Six Months Ended June 30, 2014 (a)	Total 2014 Planned Expenditures (b)	Total 2015 Planned Expenditures	Total 2016 Planned Expenditures
Utilities:				
Electric Utilities	$96,249	$250,700	$189,300	$160,500
Gas Utilities	22,176	63,000	62,000	47,600
Non-regulated Energy:				
Power Generation	48	2,500	5,200	3,200
Coal Mining	2,755	6,600	6,200	7,300
Oil and Gas	27,859	117,800	122,700	122,200
Corporate	9,013	8,700	5,900	6,100
	$158,100	$449,300	$391,300	$346,900

(a) Expenditures for the six months ended June 30, 2014 include the impact of accruals for property, plant and equipment.
(b) Includes actual expenditures for the six months ended June 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.

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. We believe that our reserves dedicated to the gathering system, and the projected volumes are adequate to materially satisfy our delivery commitments under this agreement.

Construction Commitments

Construction of Cheyenne Prairie, a 132 MW natural gas-fired electric generating facility jointly owned by Cheyenne Light and Black Hills Power is expected to cost approximately $222 million. Construction is expected to be completed by September 30, 2014. As of June 30, 2014, contracts for equipment purchases and for construction were 100% and 98% committed, respectively.

Bond Purchase Agreements

On June 30, 2014, Black Hills Power and Cheyenne Light entered into agreements to issue $160 million of first mortgage bonds to finance Cheyenne Prairie. Black Hills Power will issue $85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light will issue $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. The closing date for the sale of the first mortgage bonds for both utilities is anticipated October 1, 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, 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:

	June 30, 2014	December 31, 2013	June 30, 2013
Net derivative (liabilities) assets	$(1,647)	$(6,071)	$(7,203)
Cash collateral offset in Derivatives	3,384	6,733	7,203
Cash Collateral included in Other current assets	2,767	3,390	2,938
Net receivable (liability) position	$4,504	$4,052	$2,938

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 June 30, 2014, were as follows:

Natural Gas

	March 31,	June 30,	September 30,	December 31,	Total Year
2014					
Swaps - MMBtu	—	—	1,335,000	1,305,000	2,640,000
Weighted Average Price per MMBtu	$—	$—	$4.03	$4.04	$4.03
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	114,000
Weighted Average Price per Bbl	$—	$—	$90.55	$90.66	$90.60
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	$88.48
2016					
Swaps - Bbls	33,000	33,000	30,000	30,000	126,000
Weighted Average Price per Bbl	$83.45	$83.45	$83.33	$83.33	$83.39

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:

	June 30, 2014	December 31, 2013	June 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	2.5	3.0	3.5	0.5
Derivative liabilities, current	$3,480	$3,474	$6,965	$ 61,899
Derivative liabilities, non-current	$4,251	$5,614	$12,384	$ —
Pre-tax accumulated other comprehensive income (loss)	$(7,731)	$(9,088)	$(19,349)	$ —

(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.

At June 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.

(b) These swaps are 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 were 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 June 30, 2014 market interest rates and balances related to our interest rate swaps, a loss of approximately $3.5 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Estimated and actual realized gains or losses will change during future periods as market interest rates change.

ITEM 4. CONTROLS AND PROCEDURES

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

During the quarter ended June 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 six months ended June 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*	Credit Agreement dated May 29, 2014 among Black Hills Corporation, as Borrower, U.S. Bank, National Association, in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 30, 2014.)
Exhibit 10.2*	Bond Purchase Agreement dated as of June 30, 2014 by and among Black Hills Power, Inc., New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York and United of Omaha Life Insurance Company (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 2, 2014.)

Exhibit 10.3*	Bond Purchase Agreement dated as of June 30, 2014 by and among Cheyenne Light, Fuel and Power Company, New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York, Mutual of Omaha Insurance Company, United of Omaha Life Insurance Company and American Equity Investment Life Insurance Company (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 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.

*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: August 6, 2014

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