BLACK HILLS CORP /SD/
Form 10-Q
November 08, 2012

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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2012

OR

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

Commission File Number 001-31303

Black Hills Corporation
Incorporated in South Dakota IRS Identification Number 46-0458824
625 Ninth Street
Rapid City, South Dakota 57701

Registrant's telephone number (605) 721-1700

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).
Yes x No o

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

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x

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

Class	Outstanding at October 31, 2012
Common stock, $1.00 par value	44,180,030 shares

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GLOSSARY OF TERMS AND ABBREVIATIONS AND ACCOUNTING STANDARDS

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
AltaGas	AltaGas Renewable Energy Colorado, LLC
AOCI	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
BHC	Black Hills Corporation, the "Company"
BHEP	Black Hills Exploration and Production, Inc., representing our Oil and Gas segment, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Electric Generation	Black Hills Electric Generation, LLC, representing our Power Generation segment, a direct wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business activities of Black Hills Utility Holdings
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of the Company
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Service Company	Black Hills Service Company, a direct wholly-owned subsidiary of the Company
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
CFTC	Commodity Futures Trading Commission
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company
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 Gas	Black Hills Colorado Gas 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, a direct wholly-owned subsidiary of Black Hills Electric Generation
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
CT	Combustion Turbine
CVA	Credit Valuation Adjustment
CWIP	Construction Work-In-Progress
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 were subsequently de-designated.

Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
ECA	Energy Cost Adjustment

Enserco	Enserco Energy Inc., representing our Energy Marketing segment, sold Feb. 29, 2012
Equity Forward Instrument	Equity Forward Agreement with J.P. Morgan connected to a public offering of 4,413,519 shares of Black Hills Corporation common stock
FASB	Financial Accounting Standards Board
FDIC	Federal Deposit Insurance Corporation
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles of the United States
Global Settlement	Settlement with the utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders
IFRS	International Financial Reporting Standards
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
IPP	Independent Power Producer
IRS	Internal Revenue Service
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
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	One thousand standard cubic feet
Mcfe	One thousand standard cubic feet equivalent. Natural gas liquid is converted by dividing gallons by 7. Crude oil is converted by multiplying barrels by 6.
MMBtu	One million British thermal units
MSHA	Mine Safety and Health Administration
MW	Megawatt
MWh	Megawatt-hour
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
NGL	Natural Gas Liquids
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
OTC	Over-the-counter
PGA	Purchase Gas Adjustment
PPA	Power Purchase Agreement
REPA	Renewable Energy Purchase Agreement
Revolving Credit Facility	Our $500 million five-year revolving credit facility which commenced on Feb. 1, 2012 and expires on Feb. 1, 2017
S&P	Standard and Poor's
SEC	United States Securities and Exchange Commission
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, representing our Coal Mining segment

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

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
	(in thousands, except per share amounts)			
Revenue:				
Utilities	$214,716	$223,714	$766,317	$834,463
Non-regulated energy	32,092	25,809	88,705	76,544
Total revenue	246,808	249,523	855,022	911,007
Operating expenses:				
Utilities -				
Fuel, purchased power and cost of gas sold	62,582	86,127	283,217	400,465
Operations and maintenance	59,398	58,313	183,721	184,411
Non-regulated energy operations and maintenance	22,466	22,813	65,774	69,438
Gain on sale of operating assets	(27,285)	—	(27,285)	—
Depreciation, depletion and amortization	41,408	33,278	121,398	97,434
Taxes - property, production and severance	10,213	9,161	31,201	24,598
Impairment of long-lived assets	—	—	26,868	—
Other operating expenses	216	259	1,679	562
Total operating expenses	168,998	209,951	686,573	776,908
Operating income	77,810	39,572	168,449	134,099
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums, discounts and realized settlements on interest rate swaps)	(27,475)	(29,303)	(85,151)	(87,099)
Allowance for funds used during construction - borrowed	1,127	3,520	2,608	9,874
Capitalized interest	175	2,981	467	8,198
Unrealized gain (loss) on interest rate swaps, net	605	(38,246)	(2,902)	(40,608)
Interest income	364	536	1,428	1,547
Allowance for funds used during construction - equity	196	189	668	676
Other income (expense), net	(287)	528	2,073	1,763
Total other income (expense)	(25,295)	(59,795)	(80,809)	(105,649)
Income (loss) before equity in earnings (loss) of unconsolidated subsidiaries and income taxes	52,515	(20,223)	87,640	28,450
Equity in earnings (loss) of unconsolidated subsidiaries	22	43	(12)	1,076
Income tax benefit (expense)	(17,914)	9,017	(30,057)	(7,915)
Income (loss) from continuing operations	34,623	(11,163)	57,571	21,611
Income (loss) from discontinued operations, net of tax	(166)	638	(6,810)	2,526
Net income (loss) available for common stock	$34,457	$(10,525)	$50,761	$24,137

Income (loss) per share, Basic -				
Income (loss) from continuing operations, per share	$0.79	$(0.29)	$1.31	$0.55
Income (loss) from discontinued operations, per share	—	0.02	(0.16)	0.07
Total income (loss) per share, Basic	$0.79	$(0.27)	$1.15	$0.62
Income (loss) per share, Diluted -				
Income (loss) from continuing operations, per share	$0.78	$(0.29)	$1.31	$0.54
Income (loss) from discontinued operations, per share	—	0.02	(0.16)	0.07
Total income (loss) per share, Diluted	$0.78	$(0.27)	$1.15	$0.61
Weighted average common shares outstanding:				
Basic	43,847	39,145	43,792	39,105
Diluted	44,108	39,145	44,026	39,792
Dividends paid per share of common stock	$0.370	$0.365	$1.110	$1.095

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 Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
	(in thousands)			
Net income (loss) available for common stock	$34,457	$(10,525)	$50,761	$24,137
Other comprehensive income (loss), net of tax:				
Fair value adjustment of derivatives designated as cash flow hedges (net of tax of $1,204 and $(1,215) for the three months ended 2012 and 2011 and $1,092 and $653 for the nine months ended 2012 and 2011, respectively)	(3,591)	1,922	(3,004)	(991)
Reclassification adjustments of cash flow hedges settled and included in net income (loss) (net of tax of $13 and $(129) for the three months ended 2012 and 2011 and $890 and $(985) for the nine months ended 2012 and 2011, respectively)	28	285	(1,333)	1,907
Other comprehensive income (loss), net of tax	(3,563)	2,207	(4,337)	916
Comprehensive income (loss)	$30,894	$(8,318)	$46,424	$25,053

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)

	Sept. 30, 2012 (in thousands)	Dec. 31, 2011	Sept. 30, 2011
ASSETS			
Current assets:			
Cash and cash equivalents	$247,192	$21,628	$30,198
Restricted cash and equivalents	7,302	9,254	4,080
Accounts receivable, net	104,482	156,774	102,673
Materials, supplies and fuel	80,900	84,064	84,607
Derivative assets, current	16,063	18,583	12,177
Income tax receivable, net	11,869	9,344	4,728
Deferred income tax assets, net, current	33,681	37,202	37,931
Regulatory assets, current	24,606	59,955	45,713
Other current assets	44,823	21,266	25,269
Assets of discontinued operations	—	340,851	332,503
Total current assets	570,918	758,921	679,879
Investments	16,273	17,261	17,338
Property, plant and equipment	3,950,222	3,724,016	3,656,762
Less accumulated depreciation and depletion	(1,253,808)	(934,441)	(931,299)
Total property, plant and equipment, net	2,696,414	2,789,575	2,725,463
Other assets:			
Goodwill	353,396	353,396	353,396
Intangible assets, net	3,675	3,843	3,899
Derivative assets, non-current	1,167	1,971	3,246
Regulatory assets, non-current	191,935	182,175	142,267
Other assets, non-current	19,850	19,941	20,081
Total other assets	570,023	561,326	522,889
TOTAL ASSETS	$3,853,628	$4,127,083	$3,945,569

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)

	Sept. 30, 2012	December 31, 2011	Sept. 30, 2011
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$69,138	$104,748	$91,628
Accrued liabilities	179,284	151,319	161,650
Derivative liabilities, current	86,509	84,367	101,312
Regulatory liabilities, current	10,705	16,231	10,568
Notes payable	225,000	345,000	359,000
Current maturities of long-term debt	328,310	2,473	2,893
Liabilities of discontinued operations	—	173,929	171,685
Total current liabilities	898,946	878,067	898,736
Long-term debt, net of current maturities	942,950	1,280,409	1,282,194
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	338,194	300,988	317,864
Derivative liabilities, non-current	41,410	49,033	22,475
Regulatory liabilities, non-current	120,491	108,217	85,074
Benefit plan liabilities	167,690	177,480	124,214
Other deferred credits and other liabilities	129,630	123,553	127,007
Total deferred credits and other liabilities	797,415	759,271	676,634
Commitments and contingencies (See Notes 6, 7, 9, 11, 12 and 14)			
Stockholders' equity:			
Common stock —			
Common stock $1 par value: 100,000,000 shares authorized: issued 44,250,588; 43,957,502 and 39,491,616 shares, respectively	44,251	43,958	39,492
Additional paid-in capital	731,176	722,623	604,945
Retained earnings	478,459	476,603	467,043
Treasury stock at cost – 75,420; 32,766 and 28,041 shares, respectively	(2,354)	(970)	(810)
Accumulated other comprehensive income (loss)	(37,215)	(32,878)	(22,665)
Total stockholders' equity	1,214,317	1,209,336	1,088,005
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,853,628	$4,127,083	$3,945,569

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

	Nine Months Ended Sept. 30,	
	2012	2011
Operating activities:	(unaudited, in thousands)	
Net income (loss) available to common stock	$50,761	$24,137
(Income) loss from discontinued operations, net of tax	6,810	(2,526)
Income (loss) from continuing operations	57,571	21,611
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	121,398	97,434
Deferred financing cost amortization	5,301	5,040
Impairment of long-lived assets	26,868	—
Derivative fair value adjustments	(3,522)	(2,305)
Gain on sale of operating assets	(27,285)	—
Stock compensation	5,974	4,840
Unrealized mark-to-market (gain) loss on interest rate swaps	2,902	40,608
Deferred income taxes	28,718	20,854
Allowance for funds used during construction - equity	(668)	(676)
Employee benefit plans	15,737	10,930
Other adjustments, net	3,505	3,177
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	3,085	(21,692)
Accounts receivable, unbilled revenues and other current assets	43,447	50,649
Accounts payable and other current liabilities	(22,042)	(51,846)
Regulatory assets	15,544	22,357
Regulatory liabilities	(1,983)	5,041
Contributions to defined benefit pension plans	(25,000)	(11,050)
Other operating activities, net	(1,067)	(1,755)
Net cash provided by operating activities of continuing operations	248,483	193,217
Net cash provided by (used in) operating activities of discontinued operations	21,184	13,309
Net cash provided by operating activities	269,667	206,526
Investing activities:		
Property, plant and equipment additions	(261,414)	(326,543)
Proceeds from sale of assets	268,482	583
Investment in notes receivable	(21,832)	—
Other investing activities	5,057	1,051
Net cash provided by (used in) investing activities of continuing operations	(9,707)	(324,909)
Proceeds from sale of discontinued business operations	108,837	—
Net cash provided by (used in) investing activities of discontinued operations	(824)	(1,953)
Net cash provided by (used in) investing activities	98,306	(326,862)
Financing activities:		
Dividends paid on common stock	(48,904)	(43,169)
Common stock issued	3,835	2,199
Short-term borrowings - issuances	62,453	770,000
Short-term borrowings - repayments	(182,453)	(560,000)
Long-term debt - repayments	(11,647)	(6,169)

Other financing activities	(2,833)	(28)
Net cash provided by (used in) financing activities of continuing operations	(179,549)	162,833
Net cash provided by (used in) financing activities of discontinued operations	—	(157)
Net cash provided by (used in) financing activities	(179,549)	162,676
Net change in cash and cash equivalents	188,424	42,340
Cash and cash equivalents, beginning of period*	58,768	32,438
Cash and cash equivalents, end of period*	$247,192	$74,778

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* Includes cash of discontinued operations of $37.1 million, $44.6 million and $16.0 million at Dec. 31, 2011, Sept. 30, 2011 and Dec. 31, 2010, respectively.

See Note 3 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 2011 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 2011 Annual Report on Form 10-K filed with the SEC.

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 Sept. 30, 2012, December 31, 2011 and Sept. 30, 2011 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 gas utilities is November through March and significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended Sept. 30, 2012 and Sept. 30, 2011, and our financial condition as of Sept. 30, 2012, December 31, 2011, and Sept. 30, 2011 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.

On Feb. 29, 2012, we sold our Energy Marketing segment, which resulted in this segment being classified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification of this segment as discontinued operations. For further information see Note 17.

Certain prior year data presented in the financial statements has been reclassified to conform to the current year presentation. Specifically, the Company has reclassified deferred financing cost amortization into a separate line on the Condensed Consolidated Statements of Cash Flows. This reclassification had no effect on total assets, net income, cash flows or earnings per share.

(2) RECENTLY ADOPTED AND RECENTLY ISSUED ACCOUNTING STANDARDS AND LEGISLATION

Recently Adopted Accounting Standards and Legislation

Other Comprehensive Income: Presentation of Comprehensive Income, ASU 2011-05 and ASU 2011-12

FASB issued an accounting standards update amending accounting guidance for Comprehensive Income to improve the comparability, consistency and transparency of reporting of comprehensive income. The update amends existing guidance by allowing only two options for presenting the components of net income and other comprehensive income: (1) in a single continuous financial statement, statement of comprehensive income or (2) in two separate but consecutive financial statements, consisting of an income statement followed by a separate statement of other comprehensive income. Also, items that are reclassified from other comprehensive income to net income must be presented on the face of the financial statements. ASU 2011-05 requires retrospective application, and is effective for the fiscal years, and interim periods within those years beginning after Dec. 15, 2011. In December 2011, FASB issued ASU 2011-12, which indefinitely deferred the provisions of ASU 2011-05 requiring the presentation of reclassification adjustments on the face of the financial statements for items reclassified from other comprehensive income to net income.

At Dec. 31, 2011, we elected to early adopt the provisions of ASU 2011-05 as amended by ASU 2011-12. The adoption changed our presentation of certain financial statements, but did not have any other impact on our financial statements.

Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements, ASU 2011-04

In May 2011, FASB issued an accounting standards update amending accounting guidance for Fair Value Measurements and Disclosures to achieve common fair value measurement and disclosure requirements between GAAP and IFRS. Additional disclosure requirements in the update include: (1) for Level 3 fair value measurements - quantitative information about unobservable inputs used, a description of the valuation processes used by the entity, and a qualitative discussion about the sensitivity of the measurements to changes in the unobservable inputs; (2) for an entity's use of a non-financial asset that is different from the asset's highest and best use - the reason for the difference; (3) for financial instruments not measured at fair value but for which disclosure of fair value is required - the fair value hierarchy level in which the fair value measurements were determined; and (4) the disclosure of all transfers between Level 1 and Level 2 of the fair value hierarchy. ASU 2011-04 is effective for fiscal years, and interim periods within those years, beginning after Dec. 31, 2011. The amendment required additional details in notes to financial statements, but did not have any other impact on our financial statements. Additional disclosures are included in Notes 12 and 13.

Intangibles - Goodwill and Other: Testing Goodwill for Impairment, ASU 2011-08

In September 2011, the FASB issued an amendment to accounting guidance to Intangibles - Goodwill and Other to provide an option to perform a qualitative assessment to determine whether further impairment testing of goodwill is necessary. Specifically, an entity has the option to first assess qualitative factors to determine whether it is necessary to perform the current two-step test. If an entity believes, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount, the quantitative impairment test is required. Otherwise, no further testing is required. This standard is effective for annual and interim goodwill impairment testing performed for fiscal years beginning after Dec. 15, 2011. We perform our annual impairment testing in November of each year. The adoption of this standard will not have an impact on our financial statements.

Recently Issued Accounting Standards and Legislation

Balance Sheet: Disclosure about Offsetting Assets and Liabilities, ASU 2011-11

In December 2011, the FASB issued revised accounting guidance to amend accounting guidance for Balance Sheet related to the existing disclosure requirements for offsetting financial assets and liabilities to enhance current disclosures, as well as to improve comparability of balance sheets prepared under GAAP and IFRS. The revised disclosure guidance affects all companies that have financial instruments and derivative instruments that are either offset in the balance sheet (i.e., presented on a net basis) or subject to an enforceable master netting and/or similar arrangement. In addition, the revised guidance requires that certain enhanced quantitative and qualitative disclosures are made with respect to a company's netting arrangements and/or rights of offset associated with its financial instruments and/or derivative instruments. The revised disclosure guidance is effective on a retrospective basis for interim and annual periods beginning Jan. 1, 2013. The adoption of this standard will not have an impact on our financial position, results of operations or cash flows.

Intangible - Goodwill and Other: Testing Indefinite Lived Intangible Assets for Impairment, ASU 2012-02

In July 2012, the FASB issued an amendment to accounting guidance for Intangibles - Goodwill and Other to provide an option to perform a qualitative assessment to determine whether further impairment testing of indefinite lived intangible assets is necessary. This ASU aligns the impairment testing for intangible assets with that of goodwill as amended by ASU 2011-08. This guidance is effective for interim and annual periods beginning after Sept. 15, 2012, with early adoption permitted. The adoption of this standard will not have an impact on our financial statements.

Dodd-Frank Wall Street Reform and Consumer Protection Act, SEC Final Rule No. 34-67717 and No. 33-9338

In August 2012, the SEC approved a final rule implementing Section 1504 of Dodd-Frank. The rule requires issuers engaged in the commercial development of oil, natural gas or minerals to disclose cash payments made to a foreign government or the United States government. We are in the process of evaluating our reporting requirements. The adoption of this rule will not have an impact on our financial statements.

Additionally, in July 2012, the CFTC and SEC published final rules that define “swap,” “security-based swap” and other key terms and concepts that are critical to the implementation of the derivatives reforms required by Dodd-Frank. We are in the process of evaluating our reporting requirements. The adoption of this rule will not have an impact on our financial position, results of operations or cash flows.

(3) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Nine Months Ended	
	Sept. 30, 2012	Sept. 30, 2011
	(in thousands)	
Non-cash investing activities from continuing operations—		
Property, plant and equipment acquired with accounts payable and accrued liabilities	$39,303	$49,566
Capitalized assets associated with retirement obligations	$3,806	$—
Cash (paid) refunded during the period for continuing operations—		
Interest (net of amounts capitalized)	$(69,901)	$(60,934)
Income taxes, net	$425	$11,939

(4) MATERIALS, SUPPLIES AND FUEL

The amounts of materials, supplies and fuel included in the accompanying Condensed Consolidated Balance Sheets, by major classification, were as follows (in thousands) as of:

	Sept. 30, 2012	Dec. 31, 2011	Sept. 30, 2011
Materials and supplies	$43,847	$40,838	$37,327
Fuel - Electric Utilities	8,289	8,201	8,639
Natural gas in storage held for distribution	28,764	35,025	38,641
Total materials, supplies and fuel	$80,900	$84,064	$84,607

(5) ACCOUNTS RECEIVABLE AND ALLOWANCE FOR DOUBTFUL ACCOUNTS

Accounts receivable consists primarily of customer trade accounts. The Gas Utilities' accounts receivable balance fluctuates primarily due to seasonality. We maintain an allowance for doubtful accounts that reflects our estimate of uncollectible trade receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect our ability to collect.

Following is a summary of receivables (in thousands) as of:

Sept. 30, 2012	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$46,802	$18,441	$(603)	$64,640
Gas Utilities	18,198	9,480	(204)	27,474
Oil and Gas	10,272	—	(105)	10,167
Coal Mining	1,540	—	—	1,540
Power Generation	4	—	—	4
Corporate	657	—	—	657
Total	$77,473	$27,921	$(912)	$104,482

Dec. 31, 2011	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$42,773	$21,151	$(545)	$63,379
Gas Utilities	39,353	38,992	(1,011)	77,334
Oil and Gas	11,282	—	(105)	11,177
Coal Mining	4,056	—	—	4,056
Power Generation	282	—	—	282
Corporate	546	—	—	546
Total	$98,292	$60,143	$(1,661)	$156,774

Sept. 30, 2011	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$41,889	$16,401	$(590)	$57,700
Gas Utilities	21,168	12,518	(789)	32,897
Oil and Gas	8,820	—	(161)	8,659
Coal Mining	1,845	—	—	1,845
Power Generation	119	—	—	119
Corporate	1,453	—	—	1,453
Total	$75,294	$28,919	$(1,540)	$102,673

(6) NOTES PAYABLE

Our credit facility and debt securities contain certain restrictive financial covenants. We were in compliance with all of these covenants at Sept. 30, 2012.

We had the following short-term debt outstanding at the Condensed Consolidated Balance Sheet dates (in thousands) as of:

	Sept. 30, 2012		Dec. 31, 2011		Sept. 30, 2011	
	Notes Payable	Letters of Credit	Notes Payable	Letters of Credit	Notes Payable	Letters of Credit
Revolving Credit Facility	$75,000	$36,300	$195,000	$43,700	$209,000	$42,355
Term Loan due June 2013 (a)	150,000	—	150,000	—	150,000	—
Total	$225,000	$36,300	$345,000	$43,700	$359,000	$42,355

(a) In June 2012, this short-term loan was extended for one year. See discussion below.

Revolving Credit Facility

On Feb. 1, 2012, we entered into a new $500 million Revolving Credit Facility expiring Feb. 1, 2017. The facility contains an accordion feature allowing us, with the consent of the administrative agent, to increase the capacity of the facility to $750 million. The Revolving Credit Facility can be used for the issuance of letters of credit, to fund working capital needs and for other corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.50 percent, 1.50 percent and 1.50 percent, respectively, at Sept. 30, 2012. The facility contains a commitment fee that is charged on the unused amount of the Revolving Credit Facility. Based upon current credit ratings, the fee is 0.25 percent.

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Deferred financing costs on the Revolving Credit Facility of $2.8 million are being amortized over the estimated useful life of the Revolving Credit Facility and are included in Interest expense on the accompanying Condensed Consolidated Statements of Income. Upon entering into the Revolving Credit Facility, $1.5 million of deferred financing costs relating to the previous credit facility were written off through Interest expense.

Term Loans

On June 24, 2012, we extended the term of the $150 million term loan to June 24, 2013. The cost of borrowing is based on 1.10 percent over LIBOR.

Debt Covenants

Certain debt obligations require compliance with the following covenants at the end of each quarter (dollars in thousands):

	As of Sept. 30, 2012		Covenant Requirement		
Consolidated Net Worth	$1,214,317		Greater than	$909,511	
Recourse Leverage Ratio	56.3	%	Less than	65.0	%

(7) LONG TERM DEBT

On May 15, 2012, Black Hills Power repaid its 4.8 percent Pollution Control Revenue Bonds in full for $6.5 million principal and interest. These bonds were originally due to mature on Oct. 1, 2014.

(8) EARNINGS PER SHARE

Basic Income (loss) per share from continuing operations is computed by dividing Income (loss) from continuing operations by the weighted-average number of common shares outstanding during the period. Diluted Income (loss) per share is computed by including all dilutive common shares potentially outstanding during a period.

A reconciliation of share amounts used to compute Income (loss) per share is as follows (in thousands):

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Income (loss) from continuing operations	$34,623	$(11,163)	$57,571	$21,611
Weighted average shares - basic	43,847	39,145	43,792	39,105
Dilutive effect of:				
Restricted stock	175	—	159	147
Stock options	12	—	14	16
Equity forward instruments	—	—	—	473
Other dilutive effects	74	—	61	51
Weighted average shares - diluted	44,108	39,145	44,026	39,792

Below is a discussion of our potentially dilutive shares that were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive.

Due to our net loss for the quarter ended Sept. 30, 2011, potentially dilutive securities, consisting of outstanding stock options, restricted common stock, restricted stock units, non-vested performance-based share awards and warrants, were excluded from the diluted loss per share calculation due to their anti-dilutive effect. In computing diluted net loss per share, 11,880 options to purchase shares of common stock, 159,873 vested and non-vested restricted stock shares, 31,408 warrants and other performance shares and 424,715 forward equity instruments were excluded from the computations for the three months ended Sept. 30, 2011.

In addition to these potentially dilutive shares excluded due to our net loss for third quarter of 2011, the following outstanding securities also were excluded in the computation of diluted Income (loss) per share from continuing operations as their inclusion would have been anti-dilutive (in thousands):

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Stock options	77	176	101	119
Restricted stock	61	20	53	17
Other stock	—	27	19	19
Anti-dilutive shares	138	223	173	155

(9) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

We have three non-contributory defined benefit pension plans (Pension Plans). One covers certain eligible employees of Black Hills Service Company, Black Hills Power, WRDC and BHEP, one covers certain eligible employees of Cheyenne Light, and one covers certain eligible employees of Black Hills Energy. As of Jan. 1, 2012, all Pension Plans have been frozen to new employees and certain eligible employees who did not meet age and service based criteria at the time the Pension Plans were frozen. Additionally, effective Oct. 1, 2012, the Cheyenne Light Pension Plan was merged into the Black Hills Corporation Pension Plan. The Pension Plan benefits are based on years of service and compensation levels.

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

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Service cost	$1,431	$1,355	$4,291	$4,066
Interest cost	3,688	3,732	11,062	11,196
Expected return on plan assets	(4,084)	(4,239)	(12,252)	(12,717)
Prior service cost	22	25	66	75
Net loss (gain)	2,408	1,135	7,224	3,405
Net periodic benefit cost	$3,465	$2,008	$10,391	$6,025

Non-pension Defined Benefit Postretirement Healthcare Plans

We sponsor the following retiree healthcare plans (Healthcare Plans): the Black Hills Corporation Postretirement Healthcare Plan, the Healthcare Plan for Retirees of Cheyenne Light, and the Black Hills Energy Postretirement Healthcare Plan. Employees who participate in the Healthcare Plans and who retire on or after meeting certain eligibility requirements are entitled to postretirement healthcare benefits.

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

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Service cost	$402	$375	$1,206	$1,125
Interest cost	523	542	1,569	1,626
Expected return on plan assets	(19)	(41)	(57)	(123)
Prior service cost (benefit)	(125)	(120)	(375)	(360)
Net loss (gain)	222	169	666	507
Net periodic benefit cost	$1,003	$925	$3,009	$2,775

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives (Supplemental Plans). The Supplemental Plans are non-qualified defined benefit plans.

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

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Service cost	$243	$257	$735	$771
Interest cost	331	324	993	973
Prior service cost	1	1	3	3
Net loss (gain)	202	128	606	383
Net periodic benefit cost	$777	$710	$2,337	$2,130

Contributions

We anticipate that we will make contributions to the benefit plans during 2012 and 2013. Contributions to the Pension Plans will be made in cash, and contributions to the Healthcare Plans and the Supplemental Plans are expected to be made in the form of benefit payments. Contributions and anticipated contributions are as follows (in thousands):

	Contributions Made Three Months Ended Sept. 30, 2012	Contributions Made Nine Months Ended Sept. 30, 2012	Additional Contributions Anticipated for 2012	Contributions Anticipated for 2013
Defined Benefit Pension Plans	$—	$25,000	$—	$4,500
Non-pension Defined Benefit Postretirement Healthcare Plans	$1,063	$3,189	$1,063	$4,380
Supplemental Non-qualified Defined Benefit Plans	$278	$834	$278	$1,090

(10) BUSINESS SEGMENT INFORMATION

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.

On Feb. 29, 2012, we sold our Energy Marketing segment, Enserco, which resulted in this segment being classified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification of this segment as discontinued operations. Indirect corporate costs and inter-segment interest expense related to Enserco that have not been classified as discontinued operations have been reclassified to our Corporate segment. For further information see Note 17.

We conduct our operations through the following five reportable segments:

Utilities Group —

- Electric Utilities, which supplies electric utility service to areas in South Dakota, Wyoming, Colorado and Montana and natural gas utility service to Cheyenne, Wyo. and vicinity; and

- Gas Utilities, which supplies natural gas utility service to areas in Colorado, Iowa, Kansas and Nebraska.

Non-regulated Energy Group —

- Oil and Gas, which acquires, explores for, develops and produces crude oil and natural gas interests located in the Rocky Mountain region and other states;

- Power Generation, which produces and sells power and capacity to wholesale customers from power plants located in Wyoming and Colorado; and

- Coal Mining, which engages in the mining and sale of coal from our mine near Gillette, Wyo.

Segment information follows the accounting policies described in Note 1 of the Notes to Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

Segment information included in the accompanying Condensed Consolidated Statements of Income and Condensed Consolidated Balance Sheets was as follows (in thousands):

Three Months Ended Sept. 30, 2012	External Operating Revenues	Intercompany Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$151,281	$3,736	$14,573
Gas	63,435	—	3
Non-regulated Energy:			
Oil and Gas [(a)]	24,728	—	17,389
Power Generation	1,256	19,695	5,128
Coal Mining	6,108	8,567	1,690
Corporate [(b)]	—	—	(4,160)
Intercompany eliminations	—	(31,998)	—
Total	$246,808	$—	$34,623

Three Months Ended Sept. 30, 2011	External Operating Revenues	Intercompany Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$151,063	$2,653	$15,790
Gas	72,651	—	572
Non-regulated Energy:			
Oil and Gas	19,163	—	241
Power Generation	1,011	7,089	337
Coal Mining	9,184	8,651	555

Corporate [b][c]	—	—	(28,307)
Intercompany eliminations	—	(21,942)	(351)
Total	$253,072	$(3,549)	$(11,163)

Nine Months Ended Sept. 30, 2012	External Operating Revenues	Intercompany Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$451,974	$11,946	$37,478
Gas	314,343	—	16,369
Non-regulated Energy:			
Oil and Gas [(a)(d)]	66,994	—	(2,219)
Power Generation	3,193	56,119	15,968
Coal Mining	18,518	24,273	3,924
Corporate [(b)]	—	—	(13,949)
Intercompany eliminations	—	(92,338)	—
Total	$855,022	$—	$57,571

Nine Months Ended Sept. 30, 2011	External Operating Revenues	Intercompany Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$431,624	$9,902	$34,653
Gas	402,839	—	24,275
Non-regulated Energy:			
Oil and Gas	55,907	—	(553)
Power Generation	2,589	20,911	2,071
Coal Mining	23,064	25,806	(1,124)
Corporate [(b)(c)]	—	—	(37,299)
Intercompany eliminations	—	(61,635)	(412)
Total	$916,023	$(5,016)	$21,611

Income Statement Notes:

(a) Income (loss) from continuing operations includes a $17.7 million after-tax gain on the sale of the Williston Basin assets. See Note 15.

(b) Income (loss) from continuing operations includes $0.4 million net after-tax non-cash mark-to-market gain and $1.9 million net after-tax non-cash mark-to-market loss on interest rate swaps for the three and nine months ended Sept. 30, 2012, respectively, and a $24.9 million and $26.4 million net after-tax non-cash mark-to-market loss on interest rate swaps for the three and nine months ended Sept. 30, 2011, respectively.

(c) Certain indirect corporate costs and inter-segment interest expenses after-tax totaling $0.5 million for the three months ended Sept. 30, 2011 and $1.6 million and $1.5 million for the nine months ended Sept. 30, 2012 and 2011 were included in the Corporate segment in continuing operations and were not reclassified as discontinued operations. See Note 17 for further information.

(d) Income (loss) from continuing operations includes a $17.3 million non-cash after-tax ceiling test impairment expense. See Note 16 for further information.

Total Assets (net of inter-company eliminations) as of:	Sept. 30, 2012	Dec. 31, 2011		Sept. 30, 2011	
Utilities:					
Electric [a]	$2,302,951	$2,254,914		$1,917,184	
Gas	710,099	746,444		683,163	
Non-regulated Energy:					
Oil and Gas [b]	263,088	425,970		405,513	
Power Generation [a]	119,489	129,121		372,313	
Coal Mining	90,444	88,704		94,908	
Corporate	367,557	141,079	(c)	139,985	(c)
Discontinued operations	—	340,851	(d)	332,503	(d)
Total assets	$3,853,628	$4,127,083		$3,945,569	

(a) Upon commercial operation on Dec. 31, 2011 of the new generating facility constructed by Colorado IPP at our Pueblo Airport Generation site, the PPA under which energy and capacity is sold to Colorado Electric is accounted for as a capital lease. Therefore, commencing Dec. 31, 2011, assets previously recorded at Power Generation are now accounted for at Colorado Electric as a capital lease.

(b) 2012 includes a ceiling test impairment and the sale of the Williston Basin assets by our Oil and Gas segment. See Notes 15 and 16.

(c) Assets of the Corporate segment were reclassified due to deferred taxes that were not classified as discontinued operations.

(d) See Note 17 for further information relating to discontinued operations.

(11) 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 2011 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 with crude oil and natural gas reserves and production, fuel procurement for certain of our gas-fired generation assets and variability in revenue due to changes in gas usage at our regulated and non-regulated segments; and
- Interest rate risk associated with our variable rate credit facility, project financing floating rate debt and our derivative instruments.

Our exposure to these market risks is affected by a number of factors including the size, duration, and composition of our energy portfolio, the absolute and relative levels of interest rates and commodity prices, the volatility of these prices and rates, and the liquidity of the related interest rate and commodity markets.

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 investment grade rated companies, 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 Sept. 30, 2012, our credit exposure (exclusive of retail customers of the regulated utilities) was concentrated primarily among investment grade rated companies, cooperative utilities and federal agencies.

We actively manage our exposure to certain market and credit risks as described in Note 3 of the Notes to the Consolidated Financial Statements in our 2011 Annual Report on Form 10-K. Our derivative and hedging activities included in the accompanying Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Income are detailed below and in Note 12.

Oil and Gas Exploration and Production

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.

We hold a portfolio of swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on those OTC swaps and options. 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 are marked to fair value and are 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 Accumulated other comprehensive income (loss) and the ineffective portion, if any, is reported in Revenue.

We had the following derivatives and related balances for our Oil and Gas segment (dollars in thousands) as of:

	Sept. 30, 2012		Dec. 31, 2011		Sept. 30, 2011	
	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps
Notional (a)	537,000	7,455,250	528,000	5,406,250	414,000	4,957,250
Maximum terms in years (b)	1.00	1.00	1.25	1.75	1.00	0.25
Derivative assets, current	$1,651	$2,032	$729	$8,010	$1,885	$6,937
Derivative assets, non-current	$494	$39	$771	$1,148	$2,529	$717
Derivative liabilities, current	$527	$1,040	$2,559	$—	$—	$—
Derivative liabilities, non-current	$414	$141	$811	$7	$—	$7
Pre-tax accumulated other comprehensive income (loss)	$428	$(344)	$(1,928)	$9,152	$4,257	$7,647
Cash collateral included in Derivative liabilities	$—	$—	$—	$—	$—	$—
Cash collateral included in Other current assets	$1,126	$1,288	$—	$—	$—	$—
Expense included in Revenue (c)	$350	$54	$58	$—	$157	$—

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

(b)

Refers to the term of the derivative instrument. Assets and liabilities are classified as current or non-current based on the term of the hedged transaction and the corresponding settlement of the derivative instruments.

(c) Represents the amortization of put premiums.

Based on Sept. 30, 2012 market prices, a $1.2 million gain would be reclassified from AOCI during the next 12 months. Estimated and actual realized gains or losses will change during future periods as market prices fluctuate.

Utilities

Our utility customers are exposed to the effect of volatile natural gas prices; therefore, as allowed or required by state utility commissions, we have entered into certain 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. Gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in accordance with accounting standards for regulated utility operations. Accordingly, the hedging activity is recognized in the Condensed Consolidated Statements of Income when the related costs are recovered through our rates or adjustment mechanisms.

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

	Sept. 30, 2012		Dec. 31, 2011		Sept. 30, 2011	
	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)
Natural gas futures purchased	14,690,000	75	14,310,000	84	9,890,000	18
Natural gas options purchased	5,560,000	6	1,720,000	3	3,880,000	6
Natural gas basis swaps purchased	8,800,000	75	7,160,000	60	—	—

We had the following derivative balances related to the hedges in our Utilities (in thousands) as of:

	Sept. 30, 2012	Dec. 31, 2011	Sept. 30, 2011
Derivative assets, current	$12,380	$9,844	$3,355
Derivative assets, non-current	$634	$52	$—
Derivative liabilities, non-current	$4,527	$7,156	$1,360
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$9,318	$17,556	$11,813
Included in Derivatives:			
Cash collateral receivable (payable)	$15,740	$19,416	$12,058
Option premiums and commissions	$2,065	$880	$1,750

Financing Activities

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. Our interest rate swaps and related balances were as follows (dollars in thousands) as of:

	Sept. 30, 2012		Dec. 31, 2011		Sept. 30, 2011	
	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*
Notional	$150,000	$250,000	$150,000	$250,000	$150,000	$250,000
Weighted average fixed interest rate	5.04 %	5.67 %	5.04 %	5.67 %	5.04 %	5.67 %
Maximum terms in years	4.25	1.25	5.00	2.00	5.25	0.25
Derivative liabilities, current	$7,028	$77,914	$6,513	$75,295	$6,724	$94,588
Derivative liabilities, non-current	$18,660	$17,668	$20,363	$20,696	$21,108	$—
Pre-tax accumulated other comprehensive income (loss)	$(25,688)	$—	$(26,876)	$—	$(27,832)	$—
Year-to Date pre-tax gain (loss)	$—	$(2,902)	$—	$(42,010)	$—	$(40,608)
Cash collateral receivable (payable) included in derivative	$—	$3,310	$—	$—	$—	$—

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* Maximum terms in years reflect the amended early termination dates. If the early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date. If extended, de-designated swaps totaling $100 million notional terminate in 6.25 years and de-designated swaps totaling $150 million notional terminate in 16.25 years.

Collateral requirements based on our corporate credit rating apply to $50 million of our de-designated swaps. At our current credit ratings, we are required to post collateral for any amount by which the swaps' negative mark-to-market fair value exceeds $20 million. If our senior unsecured credit rating drops to BB+ or below by S&P, or to Ba1 or below by Moody's, we would be required to post collateral for the entire amount of the swaps' negative mark-to-market fair value.

Based on Sept. 30, 2012 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $7.0 million would be 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.

(12) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The ASC on Fair Value Measurements and Disclosure Requirements establishes a hierarchy for grouping assets and liabilities, based on significance of inputs. For additional information see Notes 3 and 4 included in our 2011 Annual Report on Form 10-K filed with the SEC. 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.

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 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

Oil and Gas Segment:

- The commodity option contracts for the Oil and Gas segment are valued under the market approach and 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 multiple third party sources and therefore support Level 2 disclosure.

- The commodity basis swaps for the Oil and Gas segment are valued under the market approach using 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 Level 2 disclosure.

Utilities Segment:

- The commodity contracts for the Utilities, 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.

Corporate Segment:

- The interest rate swaps are valued using the market valuation 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 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. The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis (in thousands):

	As of Sept. 30, 2012					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$619	$—	$—	$—	$619
Basis Swaps -- Oil	—	1,526	—	—	—	1,526
Options -- Gas	—	—	—	—	—	—
Basis Swaps -- Gas	—	2,071	—	—	—	2,071
Commodity derivatives — Utilities	—	(2,760)	34 (b)	—	15,740	13,014
Cash and cash equivalents (a)	247,192	—	—	—	—	247,192
Total	$247,192	$1,456	$34	$—	$15,740	$264,422
Liabilities:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$885	$—	$—	$—	$885
Basis Swaps -- Oil	—	56	—	—	—	56
Options -- Gas	—	—	—	—	—	—
Basis Swaps -- Gas	—	1,181	—	—	—	1,181
Commodity derivatives — Utilities	—	4,527	—	—	—	4,527
Interest rate swaps	—	124,580	—	—	(3,310)	121,270
Total	$—	$131,229	$—	$—	$(3,310)	$127,919

(a) Level 1 assets and liabilities are described in Note 13.

(b) The significant unobservable inputs used in the fair value measurement of the long-term OTC contracts are based on the average of price quotes from an independent third party market participant and the OTC contract broker. The unobservable inputs are long-term natural gas prices. Significant changes to these inputs along with the contract term would impact the derivative asset/liability and regulatory asset/liability, but will not impact the results of operations until the contract is settled under the original terms of the contract. The contracts will be classified as Level 2 once settlement is within 60 months of maturity and quoted market prices from a market exchange are available.

	As of Dec. 31, 2011					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$—	$768 [a]	$5	$—	$773
Basis Swaps -- Oil	—	727	—	—	—	727
Options -- Gas	—	—	—	—	—	—
Basis Swaps -- Gas	—	9,158	—	—	—	9,158
Commodity derivatives —Utilities	—	(9,520)	—	—	19,416	9,896
Money market funds	6,005	—	—	—	—	6,005
Total	$6,005	$365	$768 [a]	$5	$19,416	$26,559
Liabilities:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$—	$1,165 [a]	$5	$—	$1,170
Basis Swaps -- Oil	—	2,200	—	—	—	2,200
Options -- Gas	—	—	—	—	—	—
Basis Swaps -- Gas	—	7	—	—	—	7
Commodity derivatives — Utilities	—	7,156	—	—	—	7,156
Interest rate swaps	—	122,867	—	—	—	122,867
Total	$—	$132,230	$1,165 [a]	$5	$—	$133,400

(a) Of the net balance included as Level 3, transfers out of Level 3 included settlement of losses of approximately $0.5 million within AOCI and approximately $0.9 million transferred to level 2 as inputs becoming more observable.

	As of Sept. 30, 2011					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$—	$328	$—	$—	$328
Basis Swaps -- Oil	—	4,086	—	—	—	4,086
Options -- Gas	—	—	—	—	—	—
Basis Swaps -- Gas	—	7,654	—	—	—	7,654
Commodity derivatives — Utilities	—	(8,703)	—	—	12,058	3,355
Money market funds	9,006	—	—	—	—	9,006
Total	$9,006	$3,037	$328	$—	$12,058	$24,429
Liabilities:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	—	—	—	—	—
Options -- Gas	—	—	—	—	—	—
Basis Swaps -- Gas	—	7	—	—	—	7
Commodity derivatives — Utilities	—	1,360	—	—	—	1,360
Interest rate swaps	—	122,420	—	—	—	122,420
Total	$—	$123,787	$—	$—	$—	$123,787

Fair Value Measures

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis and do not reflect the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements. Further, the amounts do not include net cash collateral on deposit in margin accounts at Sept. 30, 2012, Dec. 31, 2011, and Sept. 30, 2011, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the gross 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 11.

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

As of Sept. 30, 2012

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$3,263	$—
Commodity derivatives	Derivative assets — non-current	533	—
Commodity derivatives	Derivative liabilities — current	—	1,534
Commodity derivatives	Derivative liabilities — non-current	—	555
Interest rate swaps	Derivative liabilities — current	—	7,029
Interest rate swaps	Derivative liabilities — non-current	—	18,661
Total derivatives designated as hedges		$3,796	$27,779
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$421	$3,361
Commodity derivatives	Derivative assets — non-current	—	(634)
Commodity derivatives	Derivative liabilities — current	—	33
Commodity derivatives	Derivative liabilities — non-current	—	4,527
Interest rate swaps	Derivative liabilities — current	—	77,913
Interest rate swaps	Derivative liabilities — non-current	—	20,977
Total derivatives not designated as hedges		$421	$106,177

As of Dec. 31, 2011

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$8,739	$—
Commodity derivatives	Derivative assets — non-current	1,919	—
Commodity derivatives	Derivative liabilities — current	—	2,559
Commodity derivatives	Derivative liabilities — non-current	—	818
Interest rate swaps	Derivative liabilities — current	—	6,513
Interest rate swaps	Derivative liabilities — non-current	—	20,363
Total derivatives designated as hedges		$10,658	$30,253
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$9,572
Commodity derivatives	Derivative assets — non-current	—	(52)
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	7,156
Interest rate swaps	Derivative liabilities — current	—	75,295
Interest rate swaps	Derivative liabilities — non-current	—	20,696
Total derivatives not designated as hedges		$—	$112,667

As of Sept. 30, 2011

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$8,822	$—
Commodity derivatives	Derivative assets — non-current	3,246	—
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	7
Interest rate swaps	Derivative liabilities — current	—	6,724
Interest rate swaps	Derivative liabilities — non-current	—	21,108
Total derivatives designated as hedges		$12,068	$27,839
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$8,703
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	(2)	(1,360)
Commodity derivatives	Derivative liabilities — non-current	—	—
Interest rate swaps	Derivative liabilities — current	—	94,588
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives not designated as hedges		$(2)	$101,931

A description of our derivative activities is included in Note 11. The following tables present the impact that derivatives had on our Condensed Consolidated Statements of Income.

Cash Flow Hedges

The impact of cash flow hedges on our Condensed Consolidated Statements of Income was as follows (in thousands):

Three Months Ended Sept. 30, 2012

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	$(1,684)	Interest expense	$(1,853)		$—
Commodity derivatives	(3,111)	Revenue	1,838		—
Total	$(4,795)		$(15)		$—

Three Months Ended Sept. 30, 2011

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	$(6,958)	Interest expense	$(1,930)	$—
Commodity derivatives	10,095	Revenue	1,516	—
Total	$3,137		$(414)	$—

Nine Months Ended Sept. 30, 2012

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	$(4,697)	Interest expense	$(5,518)		$—
Commodity derivatives	601	Revenue	7,741		—
Total	$(4,096)		$2,223		$—

Nine Months Ended Sept. 30, 2011

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	$(11,428)	Interest expense	$(5,741)		$—
Commodity derivatives	9,784	Revenue	2,849		—
Total	$(1,644)		$(2,892)		$—

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments that have not been designated as hedging instruments on our Condensed Consolidated Statements of Income was as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended Sept. 30, 2012 Amount of Gain/(Loss) on Derivatives Recognized in Income	Nine Months Ended Sept. 30, 2012 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swaps, net	$605	$(2,902)
Interest rate swaps - realized	Interest expense	(3,250)	(9,697)
Commodity derivatives	Revenue	(14)	(14)
		$(2,659)	$(12,613)

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended Sept. 30, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income	Nine Months Ended Sept. 30, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swaps, net	$(38,246)	$(40,608)

Interest rate swaps - realized	Interest expense	(3,373)	(10,077)
		$(41,619)	$(50,685)

(13) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments are as follows (in thousands) as of:

	Sept. 30, 2012		Dec. 31, 2011		Sept. 30, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$247,192	$247,192	$21,628	$21,628	$30,198	$30,198
Restricted cash and equivalents [(a)]	$7,302	$7,302	$9,254	$9,254	$4,080	$4,080
Notes receivable [(a)]	$21,832	$21,832	$—	$—	$—	$—
Notes payable [(b)]	$225,000	$225,000	$345,000	$345,000	$359,000	$359,000
Long-term debt, including current maturities [(c)]	$1,271,260	$1,471,932	$1,282,882	$1,464,289	$1,285,087	$1,430,271

(a) Fair value approximates carrying 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) The carrying amounts of our notes payable approximate fair value due to their variable interest rates with short reset periods.

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

The following methods and assumptions were used to estimate the fair value of each class of our financial instruments.

Cash and Cash Equivalents

Included in cash and cash equivalents are cash, overnight repurchase agreement accounts, money market funds and term deposits. As part of our cash management process, excess operating cash is invested in overnight repurchase agreements with our bank. Repurchase agreements are not deposits and are not insured by the U.S. Government, the FDIC or any other government agency and involve investment risk including possible loss of principal. We believe, however, that the market risk arising from holding these financial instruments is minimal.

Restricted Cash and Equivalents

Restricted cash and equivalents represent restricted cash and uninsured term deposits.

Notes Receivable

Notes receivable, included in Other current assets on the accompanying Condensed Consolidated Balance Sheet, represents cash held by a third party related to tax planning strategies for effecting like-kind exchange structuring for the purchase of additional oil and gas leases.

Notes Payable

Notes Payable represent our short-term corporate term loan and borrowings under our Revolving Credit Facility.

Long-term Debt

Our debt instruments are marked to fair value using the market valuation approach. The fair value for our fixed rate debt instruments is estimated based on quoted market prices and yields for debt instruments having similar maturities and debt ratings. The carrying amounts of our variable rate debt approximate fair value due to the variable interest rates with short reset periods.

(14) COMMITMENTS AND CONTINGENCIES

Commitments and Contingencies

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

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 Sept. 30, 2012, 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 Sept. 30, 2012:

- 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 Sept. 30, 2012, the restricted net assets at our Utilities Group were approximately $227.2 million.
- As required by the covenant in the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has maintained restricted equity of at least $100.0 million.

(15) SALE OF ASSETS

Oil and Gas

On Sept. 27, 2012, our Oil and Gas segment sold a majority of its Bakken and Three Forks shale assets in the Williston Basin of North Dakota. The sale included approximately 73 gross wells, 28,000 net lease acres and had an effective date of July 1, 2012.

Our Oil and Gas segment follows the full-cost method of accounting for oil and gas activities. Typically this methodology does not allow for gain or loss on sale and proceeds from sale are credited against the full cost pool. Gain or loss recognition is allowed when such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. The Sept. 27, 2012 sale significantly alters the relationship and accordingly we have recorded a gain of $27.3 million with the remainder of the proceeds recorded as a reduction in the full cost pool. This reduction in the full cost pool will decrease in the depreciation, depletion and amortization rate.

Net cash proceeds were as follows (in thousands):		
Cash proceeds received on date of sale	$243,314	
Adjustments to proceeds:		
Post close adjustments	1,490	
Transaction adviser fees	(1,400	)
Estimated payment for contractual obligation related to "back-in" fee *	(16,847	)

Net cash proceeds	$226,557

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* Required payment, triggered by the sale of the property, arising from a contractual obligation contained in the original participation agreement with the property operator.

Electric Utilities

On Sept. 18, 2012, Colorado Electric completed the sale of an undivided 50 percent ownership interest in the 29 megawatt Busch Ranch Wind project to AltaGas for $25.0 million. Colorado Electric retains the remaining undivided interest and will be the operator of this jointly owned facility. Commercial operation of the newly constructed wind farm was achieved on Oct. 16, 2012. Colorado Electric will purchase AltaGas's interest in the energy produced by the wind farm through a REPA expiring on Oct. 16, 2037.

(16) IMPAIRMENT OF LONG-LIVED ASSETS

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

As a result of continued low commodity prices, we recorded a $26.9 million non-cash impairment of oil and gas assets included in our Oil and Gas segment in the second quarter of 2012. In determining the ceiling value of our assets, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. For natural gas, the average NYMEX price was $3.15 per Mcf, adjusted to $2.66 per Mcf at the wellhead; for crude oil, the average NYMEX price was $95.67 per barrel, adjusted to $85.36 per barrel at the wellhead.

(17) DISCONTINUED OPERATIONS

On Feb. 29, 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. Net cash proceeds on the date of the sale were approximately $166.3 million, subject to final post-closing adjustments. The proceeds represent $108.8 million received from the buyer and $57.5 million cash retained from Enserco prior to closing.

Pursuant to the provisions of the stock purchase agreement, the buyer requested purchase price adjustments totaling $7.2 million. We contested this proposed adjustment and estimated the amount owed at $1.4 million, which is accrued for in the accompanying financial statements as of Sept. 30, 2012. If we do not reach a negotiated agreement with the buyer regarding the purchase price adjustment, resolution will occur through the dispute resolution provision of the stock purchase agreement.

The accompanying Condensed Consolidated Financial Statements have been classified to reflect Enserco as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification.

Operating results of the Energy Marketing segment included in Income (loss) from discontinued operations, net of tax on the accompanying Condensed Consolidated Statements of Income were as follows (in thousands):

	For the Three Months Ended		For the Nine Months Ended	
	Sept. 30, 2012	Sept. 30, 2011	Sept. 30, 2012	Sept. 30, 2011
Revenue	$—	$6,937	$(604)	$21,878
Pre-tax income (loss) from discontinued operations	$(311)	$1,495	$(6,622)	$4,404
Pre-tax gain (loss) on sale	—	—	(3,787)	—
Income tax (expense) benefit	145	(857)	3,599	(1,878)
Income (loss) from discontinued operations, net of tax [(a)]	$(166)	$638	$(6,810)	$2,526

(a) Includes transaction related costs, net of tax, of $0.2 million and $2.5 million for three and nine months ended Sept. 30, 2012, respectively.

Indirect corporate costs and inter-segment interest expense after-tax totaling $0.5 million for the three months ended Sept. 30, 2011, and $1.6 million and $1.5 million for the nine months ended Sept. 30, 2012 and 2011, respectively, were reclassified from the Energy Marketing segment to the Corporate segment in continuing operations on the accompanying Condensed Consolidated Statements of Income.

Net assets of the Energy Marketing segment included in Assets/Liabilities of discontinued operations in the accompanying Condensed Consolidated Balance Sheets were as follows (in thousands) as of:

	Dec. 31, 2011	Sept. 30, 2011
Other current assets	$280,221	$282,361
Derivative assets, current and non-current	52,859	50,519
Property, plant and equipment, net	5,828	5,391
Goodwill	1,435	1,435
Other non-current assets	508	(7,204)
Other current liabilities	(132,951)	(134,747)
Derivative liabilities, current and non-current	(26,084)	(31,978)
Other non-current liabilities	(14,894)	(4,959)
Net assets	$166,922	$160,818

(18) SUBSEQUENT EVENTS

Long-term Debt

On Oct. 31, 2012, we redeemed our $225.0 million of senior unsecured 6.5 percent notes, which were originally scheduled to mature on May 15, 2013. The total payment was $238.8 million, including accrued interest expense and a make-whole provision payment of $7.1 million.

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

We are an 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

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* On Feb. 29, 2012, we sold the stock of Enserco, our Energy Marketing segment, to a third party buyer and therefore we now classify the segment as discontinued operations.

Our Utilities Group consists of our Electric and Gas Utilities segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 201,500 customers in South Dakota, Wyoming, Colorado and Montana; and also distributes natural gas to approximately 34,800 Cheyenne Light customers in Wyoming. Our Gas Utilities serve approximately 528,800 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, Wyo. and sells the coal primarily to on-site, mine-mouth power generation facilities. Our Oil and Gas segment principally 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 with sensitivity from the degree of humidity while the normal peak usage season for gas utilities is November through March, and significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended Sept. 30, 2012 and 2011, and our financial condition as of Sept. 30, 2012, Dec. 31, 2011, and Sept. 30, 2011 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 64.

The following business group and segment information does not include intercompany eliminations. Minor differences in amounts may result due to rounding. All amounts are presented on a pre-tax basis unless otherwise indicated. Information has been revised to remove information related to the operations of our Energy Marketing segment, now classified as discontinued operations, as a result of the sale of Enserco on Feb. 29, 2012.

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended Sept. 30, 2012 Compared to Three Months Ended Sept. 30, 2011. Income from continuing operations for the three months ended Sept. 30, 2012 was $34.6 million, or $0.78 per share, compared to Loss from continuing operations of $11.2 million, or $0.29 per share, reported for the same period in 2011. The 2012 Income from continuing operations included an after-tax gain on sale of $17.7 million relating to the sale of the Williston Basin assets of our Oil and Gas segment, an incentive accrual of $2.2 million after-tax relating to the Williston Basin asset sale and a $0.4 million non-cash after-tax unrealized mark-to-market gain on certain interest rate swaps. The 2011 Loss from continuing operations included a $24.9 million after-tax non-cash unrealized mark-to-market loss on the same interest rate swaps.

Net income for the three months ended Sept. 30, 2012 was $34.5 million, or $0.78 per share, compared to Net loss of $10.5 million, or $0.27 per share, for the same period in 2011. Net income for the three months ended Sept. 30, 2012 and 2011 include the same significant items discussed above.

Nine Months Ended Sept. 30, 2012 Compared to Nine Months Ended Sept. 30, 2011. Income from continuing operations for the nine months ended Sept. 30, 2012 was $57.6 million, or $1.31 per share, compared to Income from continuing operations of $21.6 million, or $0.54 per share, reported for the same period in 2011. The 2012 Income from continuing operations included an after-tax gain of $17.7 million relating to the sale of the Williston Basin assets of our Oil and Gas segment, an incentive accrual of $2.2 million after-tax relating to the Williston Basin asset sale, a non-cash after-tax ceiling test impairment of $17.3 million, a $1.9 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps, and an after-tax write-off of $1.0 million of deferred financing costs related to our previous revolving credit facility. The 2011 Income from continuing operations included a $26.4 million after-tax unrealized non-cash mark-to-market loss on the same interest rate swaps.

Net income for the nine months ended Sept. 30, 2012 was $50.8 million, or $1.15 per share, compared to $24.1 million, or $0.61 per share, for the same period in 2011. Net income for the nine months ended Sept. 30, 2012 and 2011 include the same significant items discussed above.

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Revenue						
Utilities	$218,452	$226,367	$(7,915)	$778,263	$844,365	$(66,102)
Non-regulated Energy	60,354	45,098	15,256	169,097	128,277	40,820
Intercompany eliminations	(31,998)	(21,942)	(10,056)	(92,338)	(61,635)	(30,703)
	$246,808	$249,523	$(2,715)	$855,022	$911,007	$(55,985)
Net income (loss)						
Electric Utilities	$14,573	$15,790	$(1,217)	$37,478	$34,653	$2,825
Gas Utilities	3	572	(569)	16,369	24,275	(7,906)
Utilities	14,576	16,362	(1,786)	53,847	58,928	(5,081)
Power Generation	5,128	337	4,791	15,968	2,071	13,897
Coal Mining	1,690	555	1,135	3,924	(1,124)	5,048
Oil and Gas (a)	17,389	241	17,148	(2,219)	(553)	(1,666)
Non-regulated Energy	24,207	1,133	23,074	17,673	394	17,279
Corporate and eliminations (b)(c)	(4,160)	(28,658)	24,498	(13,949)	(37,711)	23,762
Income (loss) from continuing operations	34,623	(11,163)	45,786	57,571	21,611	35,960
Income (loss) from discontinued operations, net of tax	(166)	638	(804)	(6,810)	2,526	(9,336)
Net income (loss)	$34,457	$(10,525)	$44,982	$50,761	$24,137	$26,624

(a) Net income (loss) for three and nine months ended Sept. 30, 2012 includes a $17.7 million after-tax gain on the sale of the Williston Basin assets and Net income (loss) for the nine months ended Sept. 30, 2012 also includes a $17.3 million non-cash after-tax ceiling test impairment. See Notes 15 and 16 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b) Financial results of our Energy Marketing segment have been classified as discontinued operations. Certain indirect corporate costs and inter-segment interest expenses totaling $0.5 million after-tax for the three months ended Sept. 30, 2011 and $1.6 million and $1.5 million for the nine months ended Sept. 30, 2012 and 2011, respectively were not reclassified as discontinued operations and are included in the Corporate segment in continuing operations. See Note 17 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(c) Income (loss) from continuing operations includes $0.4 million net after-tax non-cash mark-to-market gain and $1.9 million net after-tax non-cash mark-to-market loss on interest rate swaps for the three and nine months ended Sept. 30, 2012, respectively, and a $24.9 million and $26.4 million net after-tax non-cash mark-to-market loss on interest rate swaps for the three and nine months ended Sept. 30, 2011, respectively.

Business Group highlights for 2012 include:

Utilities Group

- On Sept. 18, 2012, Colorado Electric completed the sale of a 50 percent ownership interest in the 29 megawatt Busch Ranch Wind project for $25.0 million. The wind turbine project commenced commercial operation on Oct. 16, 2012.

- On June 18, 2012, the WPSC approved a stipulation and agreement for Cheyenne Light resulting in an annual revenue increase of $2.7 million for electric customers and $1.6 million for gas customers effective July 1, 2012. The settlement also included a return on equity of 9.6 percent with a capital structure of 54 percent equity and 46 percent debt.

- On June 4, 2012, Colorado Gas filed a request with the CPUC for an increase in annual gas revenues to recover capital investments and increased operation and maintenance expenses. The CPUC required this rate case filing as part of a previous settlement agreement when we purchased Colorado Gas. All parties reached a rate case settlement and the settlement hearing was held on Oct. 12, 2012. A decision is expected in the first quarter of 2013. The settlement, if approved, includes a $0.2 million revenue increase, a return on equity of 9.6 percent and a capital structure of 50 percent equity and 50 percent debt.

- Weather was a contributing factor for our utilities for the quarter and the year. Year-to-date utility results were unfavorably impacted by warm weather, particularly at the Gas Utilities. Our service territories reported warmer weather, as measured by degree days, compared to the 30-year average and last year. Heating degree days year-to-date were 21 percent lower than weighted average norms for our Gas Utilities. When compared to colder than normal weather during the same period in 2011, heating degree days were 40 percent lower than the same period in 2011 for our Gas Utilities. For our Electric Utilities, although temperatures were above normal, weather-related demand was tempered by significantly lower humidity in 2012 than 2011 in our service territories.

- Colorado Electric's new $230 million, 180 megawatt power plant near Pueblo, Colo. began commercial operations and started serving utility customers on Jan. 1, 2012. New rates and cost adjustments were effective Jan. 1, 2012, providing an additional $30.0 million in gross margins at Colorado Electric for the nine months ended Sept. 30, 2012.

- Cheyenne Light and Black Hills Power received final approvals and permits for the Cheyenne Prairie Generating Station. The WPSC approved the CPCN on July 31, 2012 authorizing the construction, operation and maintenance of a new $237 million, 132 megawatt natural gas-fired electric generating facility in Cheyenne, Wyo. The state of Wyoming issued the air permit for the project on Aug. 31, 2012 and the U.S. Environmental Protection Agency issued the greenhouse gas air permit on Sept. 27, 2012. Upon receipt of the final permit, the major equipment for the project was ordered. Commencement of construction for the new plant is expected in spring 2013. Project costs for plant construction and associated transmission are estimated at $222 million, with up to $15 million of construction financing costs, for a total of $237 million.

- On Oct. 30, 2012 Cheyenne Light and Black Hills Power received approval from the WPSC to use a construction financing rider during construction of the Cheyenne Prairie Generating Station in lieu of traditional AFUDC. The rider allows Cheyenne Light and Black Hills Power to earn a rate of return during the construction period on the approximately 60 percent of the project cost related to serving Wyoming customers. We are evaluating filing for a similar rider in South Dakota.

- On Aug. 6, 2012 Black Hills Power and Colorado Electric announced plans to suspend plant operations at some of our older coal-fired and natural gas-fired facilities. In addition, we also identified retirement dates for the older coal-fired power plants because of federal and state environmental regulations. The affected plants are listed in the table below with their operations suspension date (if applicable) and their ultimate retirement date (if identified).

Plant	Company	Megawatts	Type of Plant	Suspend Date	Retirement Date	Age of Plant (in years)
Osage	Black Hills Power	34.5	Coal	Oct. 1, 2010	March 21, 2014	64
Ben French	Black Hills Power	25	Coal	Aug. 31, 2012	March 21, 2014	52
Neil Simpson I	Black Hills Power	21.8	Coal	NA	March 21, 2014	43
W.N. Clark	Colorado Electric	40	Coal	Dec. 31, 2012	Dec. 31, 2013	57
Pueblo Unit #5	Colorado Electric	9	Gas	Dec. 31, 2012	to be determined	71
Pueblo Unit #6	Colorado Electric	20	Gas	Dec. 31, 2012	to be determined	63

- On July 30, 2012, Colorado Electric filed its Electric Resource Plan with the CPUC seeking to develop and own replacement capacity for the retirement of the coal-fired W.N. Clark power plant, which must be retired pursuant to the Colorado Clean Air – Clean Jobs Act. The CPUC dismissed the initial filing and directed Colorado Electric to re-file an Energy Resource Plan by Jan. 18, 2013 in order to address alternatives for the replacement capacity of W.N. Clark power plant, as well as the retirement of Pueblo No. 5 and No. 6. The CPUC also directed Colorado Electric to request a CPCN for any replacement capacity that Colorado Electric seeks to develop and own.

Non-regulated Energy Group

- On Sept. 27, 2012, our Oil and Gas segment sold 85 percent of its Williston Basin assets, including approximately 73 gross wells and 28,000 net lease acres, for net cash proceeds of $226.6 million. We recognized a gain of $27.3 million on the sale. The portion of the sale amount not recognized as gain reduced the full-cost pool and will decrease our depreciation, depletion and amortization rate.

- Our Coal Mining segment received all necessary permits and approval for a revised mine plan relocating mining operations to an area in the mine with lower overburden, reducing overall mining costs for the next several years. The new mine plan went into effect during the second quarter of 2012.

- In the second quarter of 2012, our Oil and Gas segment recorded a $26.9 million non-cash ceiling test impairment loss as a result of continued low natural gas prices.

- Colorado IPP's new $261 million, 200 megawatt power plant near Pueblo, Colo. began serving customers on Jan. 1, 2012. Output from the plant is sold under a 20-year power purchase agreement to Colorado Electric.

Corporate

- On Oct. 31, 2012, we redeemed our $225.0 million of senior unsecured 6.5 percent notes, which originally were scheduled to mature on May 15, 2013.

- On June 24, 2012, we extended for one year our $150 million term loan at an interest rate of 1.10 percent over LIBOR.

- On Feb. 1, 2012, we entered into a new $500 million Revolving Credit Facility expiring Feb. 1, 2017. Deferred financing costs of $1.5 million relating to the previous credit facility were written off during the first quarter of 2012.

- We recognized a non-cash unrealized mark-to-market loss related to certain interest rate swaps of $2.9 million for the nine months ended Sept. 30, 2012 compared to a $40.6 million non-cash unrealized mark-to-market loss on these swaps for the same period in 2011.

Discontinued Operations

- On Feb. 29, 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. Net cash proceeds from the transaction were approximately $166.3 million, subject to final post-closing adjustments. Pursuant to the provisions of the stock purchase agreement, the buyer requested purchase price adjustments totaling $7.2 million. We contested this proposed adjustment and estimated the amount owed at $1.4 million, which is accrued in the accompanying financial statements as of Sept. 30, 2012. If we do not reach a negotiated agreement with the buyer regarding the purchase price adjustment, resolution will occur through the dispute resolution provision of the stock purchase agreement.

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.

Electric Utilities

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Revenue — electric	$151,465	$149,664	$1,801	$442,731	$417,512	$25,219
Revenue — gas	3,552	4,052	(500)	21,189	24,014	(2,825)
Total revenue	155,017	153,716	1,301	463,920	441,526	22,394
Fuel, purchased power and cost of gas — electric	65,992	71,387	(5,395)	191,113	203,319	(12,206)
Purchased gas — gas	1,046	1,703	(657)	11,087	13,583	(2,496)
Total fuel, purchased power and cost of gas	67,038	73,090	(6,052)	202,200	216,902	(14,702)
Gross margin — electric	85,473	78,277	7,196	251,618	214,193	37,425
Gross margin — gas	2,506	2,349	157	10,102	10,431	(329)
Total gross margin	87,979	80,626	7,353	261,720	224,624	37,096
Operations and maintenance	34,080	34,837	(757)	110,176	106,107	4,069
Gain on sale of operating assets	—	(768)	768	—	(768)	768
Depreciation and amortization	18,821	13,221	5,600	56,448	39,051	17,397
Total operating expenses	52,901	47,290	5,611	166,624	144,390	22,234
Operating income	35,078	33,336	1,742	95,096	80,234	14,862
Interest expense, net	(12,527)	(9,729)	(2,798)	(38,069)	(29,780)	(8,289)
Other income (expense), net	198	200	(2)	1,207	556	651
Income tax benefit (expense)	(8,176)	(8,017)	(159)	(20,756)	(16,357)	(4,399)
Income (loss) from continuing operations	$14,573	$15,790	$(1,217)	$37,478	$34,653	$2,825

The following tables summarize revenue, quantities generated and purchased, quantities sold, degree days and power plant availability for our Electric Utilities:

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
Revenue - Electric (in thousands)	2012	2011	2012	2011
Residential:				
Black Hills Power	$15,794	$15,034	$43,903	$44,977
Cheyenne Light	8,324	7,826	23,816	22,923
Colorado Electric	26,390	24,462	70,048	64,053
Total Residential	50,508	47,322	137,767	131,953
Commercial:				
Black Hills Power	20,336	19,889	55,948	54,962
Cheyenne Light	13,003	14,802	42,346	40,840
Colorado Electric	20,898	19,784	61,595	54,742
Total Commercial	54,237	54,475	159,889	150,544
Industrial:				
Black Hills Power	5,846	6,716	18,929	18,944
Cheyenne Light	4,551	3,017	10,863	8,573
Colorado Electric	8,476	8,086	27,689	24,520
Total Industrial	18,873	17,819	57,481	52,037
Municipal:				
Black Hills Power	930	908	2,515	2,425
Cheyenne Light	454	475	1,352	1,321
Colorado Electric	3,419	3,442	10,031	9,564
Total Municipal	4,803	4,825	13,898	13,310
Total Retail Revenue - Electric	128,421	124,441	369,035	347,844
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	5,627	4,519	14,902	13,509
Off-system Wholesale:				
Black Hills Power	5,599	9,158	23,331	23,553
Cheyenne Light	1,532	1,535	6,012	7,002
Colorado Electric (a)	1,663	—	2,073	—
Total Off-system Wholesale (a)	8,794	10,693	31,416	30,555
Other Revenue:				
Black Hills Power	7,002	8,716	22,248	21,862
Cheyenne Light	624	649	1,663	1,905
Colorado Electric	997	646	3,467	1,837
Total Other Revenue	8,623	10,011	27,378	25,604
Total Revenue - Electric	$151,465	$149,664	$442,731	$417,512

(a) Off-system sales revenue during 2010 and 2011 was deferred until a sharing mechanism was approved by the CPUC in December 2011, and recognition of 25 percent of the revenue commenced Jan. 2, 2012. As a result, Colorado Electric deferred \$2.0 million and \$8.4 million in off-system revenue during the three and nine months ended Sept. 30, 2011.

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
Quantities Generated and Purchased (in MWh)	2012	2011	2012	2011
Generated —				
Coal-fired:				
Black Hills Power	475,752	463,032	1,344,593	1,286,876
Cheyenne Light	155,099	170,643	436,576	511,209
Colorado Electric	61,820	74,470	177,712	202,381
Total Coal-fired	692,671	708,145	1,958,881	2,000,466
Gas and Oil-fired:				
Black Hills Power	21,543	11,424	28,122	13,595
Cheyenne Light	—	—	—	—
Colorado Electric	50,691	2,748	72,271	2,778
Total Gas and Oil-fired	72,234	14,172	100,393	16,373
Total Generated:				
Black Hills Power	497,295	474,456	1,372,715	1,300,471
Cheyenne Light	155,099	170,643	436,576	511,209
Colorado Electric	112,511	77,218	249,983	205,159
Total Generated	764,905	722,317	2,059,274	2,016,839
Purchased —				
Black Hills Power	280,815	409,174	1,228,072	1,186,004
Cheyenne Light	191,884	172,520	604,911	548,768
Colorado Electric	488,321	527,975	1,298,690	1,496,812
Total Purchased	961,020	1,109,669	3,131,673	3,231,584
Total Generated and Purchased:				
Black Hills Power	778,110	883,630	2,600,787	2,486,475
Cheyenne Light	346,983	343,163	1,041,487	1,059,977
Colorado Electric	600,832	605,193	1,548,673	1,701,971
Total Generated and Purchased	1,725,925	1,831,986	5,190,947	5,248,423

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
Quantity Sold (in MWh)	2012	2011	2012	2011
Residential:				
Black Hills Power	139,282	132,571	396,267	414,654
Cheyenne Light	68,816	65,643	197,093	197,053
Colorado Electric	185,696	185,775	476,425	481,774
Total Residential	393,794	383,989	1,069,785	1,093,481
Commercial:				
Black Hills Power	202,418	198,774	553,792	544,660
Cheyenne Light	141,433	157,138	449,718	446,382
Colorado Electric	198,839	201,266	548,964	547,168
Total Commercial	542,690	557,178	1,552,474	1,538,210
Industrial:				
Black Hills Power	93,147	106,658	303,906	301,268
Cheyenne Light	62,397	44,857	151,326	128,327
Colorado Electric	89,305	90,895	267,739	265,992
Total Industrial	244,849	242,410	722,971	695,587
Municipal:				
Black Hills Power	11,154	9,917	27,565	25,958
Cheyenne Light	2,318	2,528	7,028	7,122
Colorado Electric	35,461	36,657	95,649	96,483
Total Municipal	48,933	49,102	130,242	129,563
Total Retail Quantity Sold	1,230,266	1,232,679	3,475,472	3,456,841
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	88,334	84,346	249,388	256,558
Off-system Wholesale:				
Black Hills Power	190,143	299,511	943,522	819,753
Cheyenne Light	46,157	47,615	166,777	211,541
Colorado Electric	52,228	48,643	60,899	222,091
Total Off-system Wholesale	288,528	395,769	1,171,198	1,253,385
Total Quantity Sold:				
Black Hills Power	724,478	831,777	2,474,440	2,362,851
Cheyenne Light	321,121	317,781	971,942	990,425
Colorado Electric	561,529	563,236	1,449,676	1,613,508
Total Quantity Sold	1,607,128	1,712,794	4,896,058	4,966,784
Losses and Company Use:				
Black Hills Power	53,632	51,853	126,347	123,624
Cheyenne Light	25,863	25,382	69,545	69,552
Colorado Electric	39,302	41,957	98,997	88,463

Total Losses and Company Use	118,797	119,192	294,889	281,639
Total Quantity Sold	1,725,925	1,831,986	5,190,947	5,248,423

Degree Days	Three Months Ended Sept. 30, 2012		2011	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Black Hills Power	99	(56)%	153	(33)%
Cheyenne Light	170	(40)%	197	(40)%
Colorado Electric	54	(45)%	46	(50)%
Cooling Degree Days:				
Black Hills Power	731	37%	620	26%
Cheyenne Light	430	44%	399	73%
Colorado Electric	898	31%	958	36%

Degree Days	Nine Months Ended Sept. 30, 2012		2011	
	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Heating Degree Days:				
Black Hills Power	3,558	(50)%	5,050	(30)%
Cheyenne Light	3,772	(47)%	4,674	(37)%
Colorado Electric	2,753	(51)%	3,465	(38)%
Cooling Degree Days:				
Black Hills Power	937	47%	676	13%
Cheyenne Light	568	63%	429	57%
Colorado Electric	1,321	47%	1,252	36%

Electric Utilities Power Plant Availability	Three Months Ended Sept. 30, 2012	2011	Nine Months Ended Sept. 30, 2012	2011
Coal-fired plants	95.4%	95.1%	89.1%(a)	91.6%(b)
Other plants	98.5%	98.6%	96.6%	95.7%
Total availability	97.0%	96.4%	93.0%	93.1%

(a) Reflects an unplanned outage due to a transformer failure and a planned outage at Neil Simpson II, and a planned and extended overhaul at Wygen II.

(b) Reflects a major overhaul and an unplanned outage at the PacifiCorp-operated Wyodak plant.

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 Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Revenue - Gas (in thousands):				
Residential	$2,362	$2,561	$12,947	$14,592
Commercial	770	946	5,789	6,492
Industrial	248	370	1,882	2,226
Other Sales Revenue	172	175	571	704
Total Revenue - Gas	$3,552	$4,052	$21,189	$24,014
Gross Margin (in thousands):				
Residential	$1,864	$1,739	$7,092	$7,459
Commercial	417	387	2,141	2,293
Industrial	53	63	302	338
Other Gross Margin	172	160	567	341
Total Gross Margin	$2,506	$2,349	$10,102	$10,431
Volumes Sold (Dth):				
Residential	168,229	179,602	1,453,478	1,745,313
Commercial	119,344	122,138	918,131	1,048,404
Industrial	64,721	66,962	411,664	463,618
Total Volumes Sold	352,294	368,702	2,783,273	3,257,335

Results of Operations for the Electric Utilities for the Three Months Ended Sept. 30, 2012 Compared to Three Months Ended Sept. 30, 2011: Income from continuing operations for the Electric Utilities was $14.6 million for the three months ended Sept. 30, 2012 compared to $15.8 million for the three months ended Sept. 30, 2011 as a result of:

Gross margin increased primarily due to a $9.6 million increase related to rate adjustments that include a return on significant capital investments at Colorado Electric, partially offset by a $0.7 million decrease in wholesale and transmission margins as a result of decreased pricing, a decrease of $0.3 million in off-system sales and a decrease of $0.6 million from expiration of a reserve capacity agreement with PacifiCorp.

Operations and maintenance decreased primarily due to a $2.1 million reduction of major maintenance accruals related to the power plants announced for retirement and cost containment efforts, partially offset by costs associated with operating the new generating facility in Pueblo, Colo. including increased corporate allocations.

Gain on sale of operating assets in 2011 relates to the sale of assets to a related party and the gain was eliminated in the consolidation.

Depreciation and amortization increased primarily due to a higher asset base associated with the new 180 megawatt generating facility constructed in Pueblo, Colo. and the capital lease assets associated with the 200 megawatt generating facility providing capacity and energy from Colorado IPP.

Interest expense, net increased primarily due to interest associated with the financing of the Pueblo generating facility completed in December 2011. Interest costs were capitalized during construction in the prior year.

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

Income tax benefit (expense): The effective tax rate in 2012 was impacted by a unfavorable true-up adjustment while 2011 was impacted by a favorable true-up adjustment.

Results of Operations for the Electric Utilities for the Nine Months Ended Sept. 30, 2012 Compared to Nine Months Ended Sept. 30, 2011: Income from continuing operations for the Electric Utilities was $37.5 million for the nine months ended Sept. 30, 2012 compared to $34.7 million for the nine months ended Sept. 30, 2011 as a result of:

Gross margin increased primarily due to a $30.0 million increase related to rate adjustments that include a return on significant capital investments at Colorado Electric, a $1.5 million increase from wholesale and transmission margins from increased pricing, a $0.4 million increase in off-system sales mainly from higher quantities sold, a $1.2 million increase from an Environmental Improvement Cost Recovery Adjustment rider at Black Hills Power and increased retail margins as a result of higher quantities sold driven by warmer weather partially offset by a decrease of $0.6 million from the expiration of a reserve capacity agreement with PacifiCorp.

Operations and maintenance increased primarily due to the costs associated with operating the new generating facility in Pueblo, Colo. including increased corporate allocations partially offset by a $2.1 million reduction of major maintenance accruals related to the power plants announced for retirement and cost containment efforts.

Gain on sale of operating assets in 2011 relates to the sale of assets to a related party and the gain was eliminated in the consolidation.

Depreciation and amortization increased primarily due to a higher asset base associated with the new 180 megawatt generating facility in Pueblo, Colo. and the capital lease assets associated with the 200 megawatt generating facility providing capacity and energy from Colorado IPP.

Interest expense, net increased primarily due to interest associated with financing of the Pueblo generating facility completed in December 2011. Interest costs were capitalized during construction in the prior year.

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

Income tax benefit (expense): The effective tax rate increased due to a favorable benefit in the prior year for a repairs deduction taken for tax purposes and the flow-through treatment of such tax benefit.

Gas Utilities

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Natural gas — regulated	$56,845	$65,887	$(9,042)	$293,047	$382,517	$(89,470)
Other — non-regulated services	6,590	6,764	(174)	21,296	20,322	974
Total revenue	63,435	72,651	(9,216)	314,343	402,839	(88,496)
Natural gas — regulated	20,802	29,693	(8,891)	154,342	229,152	(74,810)
Other — non-regulated services	3,383	3,480	(97)	10,272	10,260	12
Total cost of sales	24,185	33,173	(8,988)	164,614	239,412	(74,798)
Gross margin	39,250	39,478	(228)	149,729	163,427	(13,698)
Operations and maintenance	28,339	28,317	22	88,121	91,126	(3,005)
Depreciation and amortization	6,338	6,064	274	18,748	18,032	716
Total operating expenses	34,677	34,381	296	106,869	109,158	(2,289)
Operating income (loss)	4,573	5,097	(524)	42,860	54,269	(11,409)
Interest expense, net	(5,370)	(6,329)	959	(17,659)	(19,640)	1,981
Other income (expense), net	(2)	27	(29)	82	176	(94)
Income tax benefit (expense)	802	1,777	(975)	(8,914)	(10,530)	1,616
Income (loss) from continuing operations	$3	$572	$(569)	$16,369	$24,275	$(7,906)

The following tables summarize revenue, gross margin, volumes sold and degree days for our Gas Utilities:

Revenue (in thousands)	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Residential:				
Colorado	$4,498	$5,493	$33,837	$39,228
Nebraska	11,370	12,736	65,832	91,798
Iowa	9,776	11,235	56,216	77,259
Kansas	7,354	7,928	36,537	46,449
Total Residential	32,998	37,392	192,422	254,734
Commercial:				
Colorado	898	1,352	6,525	8,167
Nebraska	2,742	3,520	20,760	29,823
Iowa	3,988	4,397	24,495	33,082
Kansas	1,973	2,076	10,702	14,316
Total Commercial	9,601	11,345	62,482	85,388
Industrial:				
Colorado	1,110	1,174	1,756	1,872
Nebraska	306	194	735	530
Iowa	357	334	1,551	1,478
Kansas	7,078	10,437	12,314	18,406
Total Industrial	8,851	12,139	16,356	22,286
Transportation:				
Colorado	113	84	616	591
Nebraska	1,866	1,626	7,337	8,057
Iowa	816	687	3,044	2,839
Kansas	1,338	1,311	4,367	4,503
Total Transportation	4,133	3,708	15,364	15,990
Other Sales Revenue:				
Colorado	15	22	65	78
Nebraska	469	432	1,561	1,551
Iowa	86	122	350	441
Kansas	692	727	4,447	2,049
Total Other Sales Revenue	1,262	1,303	6,423	4,119
Total Regulated Revenue	56,845	65,887	293,047	382,517
Non-regulated Services	6,590	6,764	21,296	20,322
Total Revenue	$63,435	$72,651	$314,343	$402,839

Gross Margin (in thousands)	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Residential:				
Colorado	$2,548	$2,695	$11,375	$12,575
Nebraska	8,334	8,480	32,922	37,861
Iowa	7,850	8,291	28,373	34,885
Kansas	5,622	5,465	20,537	21,663
Total Residential	24,354	24,931	93,207	106,984
Commercial:				
Colorado	399	460	1,818	2,105
Nebraska	1,404	1,486	7,027	8,462
Iowa	1,890	1,862	7,723	8,458
Kansas	1,087	1,006	4,365	4,731
Total Commercial	4,780	4,814	20,933	23,756
Industrial:				
Colorado	307	239	509	402
Nebraska	99	48	204	139
Iowa	56	38	172	176
Kansas	1,096	1,144	2,090	2,136
Total Industrial	1,558	1,469	2,975	2,853
Transportation:				
Colorado	113	84	617	590
Nebraska	1,866	1,626	7,337	8,057
Iowa	816	687	3,044	2,839
Kansas	1,338	1,311	4,367	4,503
Total Transportation	4,133	3,708	15,365	15,989
Other Sales Margins:				
Colorado	15	22	65	78
Nebraska	469	433	1,562	1,552
Iowa	86	122	351	441
Kansas	648	695	4,248	1,712
Total Other Sales Margins	1,218	1,272	6,226	3,783
Total Regulated Gross Margin	36,043	36,194	138,706	153,365
Non-regulated Services	3,207	3,284	11,023	10,062
Total Gross Margin	$39,250	$39,478	$149,729	$163,427

Volumes Sold (in Dth)	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Residential:				
Colorado	372,722	450,778	3,773,819	4,298,162
Nebraska	681,361	764,676	6,032,705	8,607,301
Iowa	479,912	564,426	5,486,267	7,485,204
Kansas	422,708	461,169	3,581,184	4,710,725
Total Residential	1,956,703	2,241,049	18,873,975	25,101,392
Commercial:				
Colorado	98,453	145,413	804,701	980,931
Nebraska	315,832	373,386	2,606,223	3,465,363
Iowa	527,923	486,758	3,424,736	4,375,492
Kansas	219,870	203,109	1,439,351	1,830,720
Total Commercial	1,162,078	1,208,666	8,275,011	10,652,506
Industrial:				
Colorado	265,451	202,956	416,020	318,278
Nebraska	69,229	30,816	134,931	67,010
Iowa	74,535	56,401	297,494	234,864
Kansas	1,912,296	2,010,001	3,381,657	3,518,599
Total Industrial	2,321,511	2,300,174	4,230,102	4,138,751
Total Volumes Sold	5,440,292	5,749,889	31,379,088	39,892,649
Transportation:				
Colorado	98,893	75,828	607,469	604,493
Nebraska	6,453,607	5,910,136	20,042,972	18,546,617
Iowa	4,038,804	4,068,243	13,718,759	13,647,342
Kansas	3,993,675	4,331,612	11,640,182	11,712,421
Total Transportation	14,584,979	14,385,819	46,009,382	44,510,873
Other Volumes:				
Colorado	—	—	—	—
Nebraska	—	—	—	—
Iowa	—	—	—	—
Kansas (a)	8,427	4,086	40,380	66,152
Total Other Volumes	8,427	4,086	40,380	66,152
Total Volumes and Transportation Sold	20,033,698	20,139,794	77,428,850	84,469,674

(a) Other volumes represent wholesale customers.

	Three Months Ended Sept. 30, 2012		Nine Months Ended Sept. 30, 2012	
Heating Degree Days:	Actual	Variance From Normal	Actual	Variance From Normal
Colorado	116	(39)%	3,018	(23)%
Nebraska	110	12%	2,880	(22)%
Iowa	216	21%	3,629	(19)%
Kansas (a)	42	(35)%	2,373	(21)%
Combined (b)	150	5%	3,176	(21)%

	Three Months Ended Sept. 30, 2011		Nine Months Ended Sept. 30, 2011	
Heating Degree Days:	Actual	Variance From Normal	Actual	Variance From Normal
Colorado	116	(38)%	3,717	(7)%
Nebraska	157	49 %	4,023	4 %
Iowa	235	38 %	4,780	3 %
Kansas (a)	54	74 %	3,085	1 %
Combined (b)	178	36 %	4,247	2 %

(a) Our gross margin in Kansas utilizes normal degree days from an approved weather normalization mechanism.

(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas which has an approved weather normalization mechanism.

Our Gas Utilities are highly seasonal, and sales volumes vary considerably with weather and seasonal heating and industrial loads. Over 70 percent 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 Nov. 1 and ends around March 31.

Results of Operations for the Gas Utilities for the Three Months Ended Sept. 30, 2012 Compared to Three Months Ended Sept. 30, 2011: Income from continuing operations for the Gas Utilities was $0.0 million for the three months ended Sept. 30, 2012 compared to Income from continuing operations of $0.6 million for the three months ended Sept. 30, 2011 as a result of:

Gross margin was comparable to the same period in the prior year.

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 lower interest rates.

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

Income tax benefit (expense): The deviation in the effective tax rate from the statutory rate is the result of a favorable true-up adjustment that had a more pronounced impact in 2012 due to significantly lower pre-tax net loss. The prior year also realized a favorable true up adjustment for flow-through treatment of certain property-related temporary differences.

Results of Operations for the Gas Utilities for the Nine Months Ended Sept. 30, 2012 Compared to Nine Months Ended Sept. 30, 2011: Income from continuing operations for the Gas Utilities was $16.4 million for the nine months ended Sept. 30, 2012 compared to Income from continuing operations of $24.3 million for the nine months ended Sept. 30, 2011 as a result of:

Gross margin decreased primarily due to a $9.6 million impact from milder weather compared to the same period in the prior year. Heating degree days were 25 percent lower for the nine months ended Sept. 30, 2012 compared to the same period in the prior year and 21 percent lower than normal. A reclassification adjustment was made in the current year, recording $4.9 million against gross margin in prior year that was included in operations and maintenance.

Operations and maintenance decreased primarily due to lower bad debt costs, cost efficiencies and a reclassification accounting adjustment that was made in the current year recording $4.9 million of operating costs in gross margin.

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

Interest expense, net decreased primarily due to lower interest rates.

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

Income tax benefit (expense): The effective tax rate increased as a result of an unfavorable state true-up adjustment. Additionally, the 2011 period was favorably impacted as a result of federal research and development credits and a flow-through tax adjustment at Iowa Gas.

Regulatory Matters — Utilities Group

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

				Revenue	Revenue		Approved Capital Structure	
	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved	Return on Equity	Equity	Debt
Nebraska Gas (1)	Gas	12/2009	9/2010	$12.1	$8.3	10.1%	52.0%	48.0%
Iowa Gas (2)	Gas	6/2010	2/2011	$4.7	$3.4	Global Settlement	Global Settlement	Global Settlement
Colorado Electric (2)	Electric	4/2011	1/2012	$40.2	$28.0	9.8% - 10.2%	49.1%	50.9%
Cheyenne Light (3)	Electric/Gas	12/2011	7/2012	$8.5	$4.3	9.6%	54.0%	46.0%
Black Hills Power (2)	Electric	1/2011	6/2011	Not Applicable	$3.1	Not Applicable	Not Applicable	Not Applicable
Colorado Gas (4)	Gas	6/2012	Pending	$1.0	Pending	Pending	Pending	Pending

(1) The Nebraska Public Advocate filed an appeal with the District Court related to the rate case decision which has been denied. Subsequently, the Nebraska Public Advocate filed a notice of appeal in the Court of Appeals. On March 20, 2012, the Court of Appeals affirmed the earlier decision of the District Court. The Nebraska Public Advocate petitioned the Nebraska Supreme Court to hear an appeal which was denied. Accordingly, the appeals of the rate case decision have been exhausted and the rate case decision is upheld as a final decision of the NPSC.

(2) These rate settlements were the most recent for the jurisdiction and were previously described in our 2011 Annual Report on Form 10-K.

(3) On June 18, 2012, the WPSC approved a settlement agreement resulting in annual revenue increases of $2.7 million for electric customers and $1.6 million for gas customers effective July 1, 2012. The cost adjustment mechanism relating to transmission, fuel and purchased power costs was modified to eliminate the $1.0 million threshold and changed the sharing mechanism to 85 percent to the customer for these cost adjustment mechanisms. The agreement approved a return on equity of 9.6 percent with a capital structure of 54 percent equity and 46 percent debt.

(4) On June 4, 2012, Colorado Gas filed a request with the CPUC for an increase in annual gas revenues of $1.0 million to recover capital investments and increased operation and maintenance expenses. The CPUC required this rate case filing as part of a previous settlement agreement when we purchased Colorado Gas. All parties reached a rate case settlement, and the settlement hearing was held on Oct. 12, 2012. A decision is expected in the first quarter of 2013. The settlement, if approved, includes a $0.2 million revenue increase, a return on equity of 9.6 percent and a capital structure of 50 percent equity and 50 percent debt.

Non-regulated Energy Group

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

For more than 15 years, we also owned and operated Enserco, an energy marketing business that engaged in natural gas, crude oil, coal, power and environmental marketing and trading in the United States and Canada. We sold Enserco on Feb. 29, 2012, which resulted in our Energy Marketing segment being classified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification of this segment as discontinued operations.

Power Generation

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Revenue	$20,951	$8,100	$12,851	$59,312	$23,500	$35,812
Operations and maintenance	7,788	4,602	3,186	22,486	12,881	9,605
Depreciation and amortization	1,165	1,064	101	3,395	3,168	227
Total operating expense	8,953	5,666	3,287	25,881	16,049	9,832
Operating income	11,998	2,434	9,564	33,431	7,451	25,980
Interest expense, net	(3,085)	(1,835)	(1,250)	(11,800)	(5,461)	(6,339)
Other (expense) income	(4)	(5)	1	10	1,220	(1,210)
Income tax (expense) benefit	(3,781)	(257)	(3,524)	(5,673)	(1,139)	(4,534)
Income (loss) from continuing operations	$5,128	$337	$4,791	$15,968	$2,071	$13,897

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

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Contracted power plant fleet availability:				
Coal-fired plant	99.4 %	97.1 %	99.5 %	98.9 %
Natural gas-fired plants	99.4 %	100.0 %	99.3 %	100.0 %
Total availability	99.4 %	98.1 %	99.4 %	99.3 %

Results of Operations for Power Generation for the Three Months Ended Sept. 30, 2012 Compared to Three Months Ended Sept. 30, 2011: Income from continuing operations for the Power Generation segment was $5.1 million for the three months ended Sept. 30, 2012 compared to Income from continuing operations of $0.3 million for the same period in 2011 as a result of:

Revenue increased due to the commencement of commercial operation of our new 200 megawatt generating facility in Pueblo, Colo. on Jan. 1, 2012.

Operations and maintenance increased primarily due to the costs to operate and corporate allocations relating to our new 200 megawatt generating facility in Pueblo, Colo., which began serving customers on Jan. 1, 2012.

Depreciation and amortization was comparable to the same period in the prior year. The new generating facility's PPA to supply capacity and energy to Colorado Electric is accounted for as a capital lease under GAAP; as such, depreciation expense for the facility is recorded at Colorado Electric for segment reporting purposes.

Interest expense, net increased due to interest costs for financing the Pueblo generating facility. Interest costs were capitalized during construction in the prior year.

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

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

Results of Operations for Power Generation for the Nine Months Ended Sept. 30, 2012 Compared to Nine Months Ended Sept. 30, 2011: Income from continuing operations for the Power Generation segment was $16.0 million for the nine months ended Sept. 30, 2012 compared to Income from continuing operations of $2.1 million for the same period in 2011 as a result of:

Revenue increased due to the commencement of commercial operation of our new 200 megawatt generating facility in Pueblo, Colo. on Jan. 1, 2012.

Operations and maintenance increased primarily due to the costs to operate and corporate allocations relating to our new 200 megawatt generating facility in Pueblo, Colo. on Jan. 1, 2012.

Depreciation and amortization was comparable to the same period in the prior year. The new generating facility's PPA to supply capacity and energy to Colorado Electric is accounted for as a capital lease under GAAP; as such, depreciation expense for the facility is recorded at Colorado Electric for segment reporting purposes.

Interest expense, net increased due to interest costs for financing the Pueblo generating facility. Interest costs were capitalized during construction in the prior year.

Other (expense) income, net in 2011 included a gain on sale of ownership interest in the partnership that held the Idaho generating facilities.

Income tax (expense) benefit: The effective tax rate in 2012 was impacted by a favorable state tax true-up that included certain tax credits. Such credits are the result of meeting certain applicable state requirements including the ability to utilize these tax credits. The tax credits pertain to qualified plant expenditures related to capital investment and research and development.

Coal Mining

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Revenue	$14,675	$17,835	$(3,160)	$42,791	$48,870	$(6,079)
Operations and maintenance	10,780	14,171	(3,391)	32,141	41,754	(9,613)
Depreciation, depletion and amortization	2,922	5,151	(2,229)	9,573	14,364	(4,791)
Total operating expenses	13,702	19,322	(5,620)	41,714	56,118	(14,404)
Operating income (loss)	973	(1,487)	2,460	1,077	(7,248)	8,325
Interest income, net	1	972	(971)	1,159	2,868	(1,709)
Other income	525	532	(7)	2,052	1,650	402
Income tax benefit (expense)	191	538	(347)	(364)	1,606	(1,970)

Income (loss) from continuing operations	$1,690	$555	$1,135	$3,924	$(1,124)	$5,048

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

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Tons of coal sold	1,105	1,550	3,191	4,155
Cubic yards of overburden moved	1,827	3,873	6,749	10,261

Results of Operations for Coal Mining for the Three Months Ended Sept. 30, 2012 Compared to Three Months Ended Sept. 30, 2011: Income from continuing operations for the Coal Mining segment was $1.7 million for the three months ended Sept. 30, 2012 compared to Income from continuing operations of $0.6 million for the same period in 2011, as a result of:

Revenue decreased primarily due to a 29 percent decrease in tons sold as a result of the December 2011 expiration of an unprofitable train load-out contract which represented approximately 29 percent of our tons sold in 2011, partially offset by an increase in average sales price as a result of price escalators and adjustments in certain of our sales contracts. Approximately 50 percent of our current coal production is sold under contracts that include price adjustments based on actual mining costs.

Operations and maintenance decreased primarily due to reduced overburden moved related to lower sales volumes and mining efficiencies, including decreased fuel costs and headcount reductions as a result of the revised mine plan and termination of the train load-out contract at Dec. 31, 2011.

Depreciation, depletion and amortization decreased primarily due to lower equipment usage and lower depreciation of mine reclamation asset retirement costs.

Interest income, net decreased primarily due to a decrease in inter-company notes receivable upon payment of a dividend to our parent.

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

Income tax benefit (expense): The change in the effective tax rate was primarily due to the impact of percentage depletion and a tax return true-up.

Results of Operations for Coal Mining for the Nine Months Ended Sept. 30, 2012 Compared to Nine Months Ended Sept. 30, 2011: Income from continuing operations for the Coal Mining segment was $3.9 million for the nine months ended Sept. 30, 2012 compared to Loss from continuing operations of $1.1 million for the same period in 2011, as a result of:

Revenue decreased primarily due to a 23 percent decrease in tons sold. This decrease was due to the December 2011 expiration of an unprofitable train load-out contract, which represented approximately 29 percent of our tons sold in 2011. Additionally, tons sold decreased due to a planned and unplanned outages at Neil Simpson II and a planned and extended outage at the Wygen II facility partially offset by increased tons sold to the Wyodak plant that experienced an outage in 2011. Approximately 50 percent of our current coal production is sold under contracts that include price adjustments based on actual mining cost increases.

Operations and maintenance decreased primarily due to reduced overburden moved related to lower tons sold and mining efficiencies, including decreased fuel costs and headcount reductions resulting from the revised mine plan and termination of the train load-out contract at Dec. 31, 2011.

Depreciation, depletion and amortization decreased primarily due to lower equipment usage and lower depreciation of mine reclamation asset retirement costs.

Interest income, net decreased primarily due to a decrease in inter-company notes receivable upon payment of a dividend to our parent.

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

Income tax benefit (expense): The change in the effective tax rate was primarily due to the impact of percentage depletion, a tax return true-up and the impact in 2011 of a favorable research and development credit.

Oil and Gas

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Revenue	$24,728	$19,163	$5,565	$66,994	$55,907	$11,087
Operations and maintenance	12,118	9,573	2,545	33,290	30,327	2,963
Gain on sale of operating assets	(27,285)	—	(27,285)	(27,285)	—	(27,285)
Depreciation, depletion and amortization	12,457	7,714	4,743	34,813	22,637	12,176
Impairment of long-lived assets	—	—	—	26,868	—	26,868
Total operating expenses	(2,710)	17,287	(19,997)	67,686	52,964	14,722
Operating income (loss)	27,438	1,876	25,562	(692)	2,943	(3,635)
Interest expense, net	(1,112)	(1,460)	348	(3,882)	(4,232)	350
Other income (expense), net	77	54	23	193	(43)	236
Income tax benefit (expense)	(9,014)	(229)	(8,785)	2,162	779	1,383
Income (loss) from continuing operations	$17,389	$241	$17,148	$(2,219)	$(553)	$(1,666)

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

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Production:				
Bbls of oil sold	184,423	98,950	485,262	303,401
Mcf of natural gas sold	2,278,801	2,147,172	7,119,087	6,264,460
Gallons of NGL sold	1,099,198	993,752	2,751,409	2,847,011
Mcf equivalent sales	3,542,367	2,882,837	10,423,717	8,491,582

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	2012	2011	2012	2011
Average price received: [(a)]				
Oil/Bbl	$88.69	$82.76	$81.65	$76.25
Gas/Mcf	$3.07	$4.24	$3.27	$4.39
NGL/gallon	$0.65	$0.88	$0.77	$0.94
Depletion expense/Mcfe	$3.26	$2.38	$3.07	$2.38

(a) Net of hedge settlement gains and losses.

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

	Three Months Ended Sept. 30, 2012				Three Months Ended Sept. 30, 2011			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.42	$0.33	$0.46	$2.21	$1.06	$0.25	$0.52	$1.83
Piceance *	0.13	0.35	0.14	0.62	0.80	0.63	0.28	1.71
Powder River	1.00	—	1.11	2.11	1.20	—	1.26	2.46
Williston	0.70	—	1.48	2.18	1.01	—	1.74	2.75
All other properties	1.48	—	0.25	1.73	0.62	—	0.38	1.00
Total weighted average	$0.99	$0.17	$0.74	$1.90	$0.99	$0.18	$0.72	$1.89

	Nine Months Ended Sept. 30, 2012				Nine Months Ended Sept. 30, 2011			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.14	$0.28	$0.34	$1.76	$1.17	$0.35	$0.54	$2.06
Piceance *	0.20	0.39	0.13	0.72	0.77	0.73	0.06	1.56
Powder River	1.33	—	1.17	2.50	1.31	—	1.31	2.62
Williston	0.65	—	1.35	2.00	0.59	—	1.58	2.17
All other properties	1.58	—	0.17	1.75	1.17	—	0.26	1.43
Total weighted average	$0.96	$0.17	$0.63	$1.76	$1.11	$0.23	$0.70	$2.04

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* Decrease in LOE is primarily due to increased volumes from two additional wells that commenced production in December 2011.

Results of Operations for Oil and Gas for the Three Months Ended Sept. 30, 2012 Compared to Three Months Ended Sept. 30, 2011: Income from continuing operations for the Oil and Gas segment was $17.4 million for the three months ended Sept. 30, 2012 compared to Income from continuing operations of $0.2 million for the same period in 2011 as a result of:

Revenue increased primarily due to an 86 percent increase in crude oil sales, due primarily to activities from new wells in our drilling program in the Bakken shale formation and a 7 percent increase in the average price received for crude oil sold. A 6 percent increase in natural gas and NGL volumes, due primarily to the production from three Mancos formation test wells in the San Juan and Piceance Basins, was partially offset by a 28 percent decrease in the average price received for natural gas.

Operations and maintenance costs increased primarily due to higher costs from non-operated wells and higher compensation and benefit costs.

Depreciation, depletion and amortization increased primarily due to the year-to-date impact from adjusting expected 2012 reserve additions due to the deferred drilling activities in the San Juan Mancos formation, as well as higher cost reserves associated with our Bakken activities and a higher depletion rate per Mcfe on higher volumes.

Gain on sale of operating assets represents the gain on the sale of our Williston Basin assets. We follow the full-cost method of accounting for oil and gas activities, which typically does not allow for gain on sale recognition unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves. The remainder of the sales amount, not recognized as gain, reduces the full-cost pool and should significantly decrease the future depreciation, depletion and amortization rate.

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

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

Income tax (expense) benefit: For 2012, the benefit generated by percentage depletion had a significantly reduced impact on the effective tax rate compared to the same period in 2011.

Results of Operations for Oil and Gas for the Nine Months Ended Sept. 30, 2012 Compared to Nine Months Ended Sept. 30, 2011: Loss from continuing operations for the Oil and Gas segment was $2.2 million for the nine months ended Sept. 30, 2012 compared to Loss from continuing operations of $0.6 million for the same period in 2011 as a result of:

Revenue increased primarily due to a 60 percent increase in crude oil volume sold along with a 7 percent increase in the average price received for crude oil sales. Crude oil production increases reflect volumes from new wells in our drilling program in the Bakken shale formation. A 13 percent increase in natural gas and NGL volumes, due primarily to the production from three Mancos formation test wells in the San Juan and Piceance Basins, was partially offset by a 26 percent decrease in average price received for natural gas.

Operations and maintenance costs increased primarily due to higher costs from non-operated wells and higher compensation and benefit costs.

Depreciation, depletion and amortization increased primarily due to the year-to-date impact from adjusting our expected 2012 reserve additions due to the deferred drilling activities in the San Juan Mancos formation, as well as higher cost reserves associated with our Bakken activities and a higher depletion rate per Mcfe on higher volumes.

Gain on sale of operating assets represents the gain on the sale of our Williston Basin assets. We follow the full-cost method of accounting for oil and gas activities, which typically does not allow for gain on sale recognition unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves. The remainder of the sale amount not recognized as gain, reduced the full-cost pool and will decrease our depreciation, depletion and amortization rate.

Impairment of long-lived assets represents a write-down in the value of our natural gas and crude oil properties driven by low natural gas prices. The write-down reflected a 12-month average NYMEX price of $3.15 per Mcf, adjusted to $2.66 per Mcf at the wellhead, for natural gas, and $95.67 per barrel, adjusted to $85.36 per barrel at the wellhead, for crude oil.

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

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

Income tax (expense) benefit: The effective tax rate for the nine months ended Sept. 30, 2011 was positively impacted by a research and development credit and the benefit generated by percentage depletion had a significantly lesser impact on the effective tax rate in 2012 compared to the same period in 2011.

Corporate

Results of Operations for Corporate for the Three Months Ended Sept. 30, 2012 Compared to Three Months Ended Sept. 30, 2011: Loss from continuing operations for Corporate was $4.2 million for the three months ended Sept. 30, 2012 compared to Loss from continuing operations of $28.3 million for the three months ended Sept. 30, 2011. The loss for the quarter ended Sept. 30, 2012 was primarily due to an incentive compensation accrual recorded as a result of the Williston Basin asset sale offset by an unrealized, non-cash mark-to-market gain on certain interest rate swaps of approximately $0.6 million. The loss for the quarter ended Sept. 30, 2011 was primarily due to a $38.2 million unrealized, non-cash mark-to-market loss on these interest rate swaps.

Costs of $0.5 million after-tax previously allocated to our Energy Marketing segment were reclassified to the Corporate segment consistent with accounting for discontinued operations for the three months ended Sept. 30, 2011. There were no allocated costs related to our Energy Marketing segment for the three months ended Sept. 30, 2012.

Results of Operations for Corporate for the Nine Months Ended Sept. 30, 2012 Compared to Nine Months Ended Sept. 30, 2011: Loss from continuing operations for Corporate was $13.9 million for the nine months ended Sept. 30, 2012 compared to Loss from continuing operations of $37.3 million for the nine months ended Sept. 30, 2011. The loss for the nine months ended Sept. 30, 2012 was primarily due to an incentive compensation accrual recorded as a result of the Williston Basin asset sale and an unrealized, non-cash mark-to-market loss on certain interest rate swaps of approximately $2.9 million. The loss for the nine months ended Sept. 30, 2011 was primarily due to a $40.6 million unrealized, non-cash mark-to-market loss on these interest rate swaps.

Costs of $1.6 million after-tax previously allocated to our Energy Marketing segment were reclassified to the Corporate segment consistent with accounting for discontinued operations for the nine months ended Sept. 30, 2012 compared to after-tax costs of $1.5 million for the nine months ended Sept. 30, 2011.

Discontinued Operations

Results of Operations for Discontinued Operations for the Three and Nine Months Ended Sept. 30, 2012, Compared to Three and Nine Months Ended Sept. 30, 2011:

On Feb. 29, 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. Net cash proceeds on the date of the sale were approximately $166.3 million, subject to final post-closing adjustments. The proceeds represent $108.8 million received from the buyer and $57.5 million cash retained from Enserco prior to closing.

Loss from discontinued operations for the three months ended Sept. 30, 2012 was $0.2 million relating to additional operating costs to discontinue the operations and $6.8 million for the nine months ended Sept. 30, 2012, including an after-tax loss on sale of $2.4 million and transaction related costs, net of tax benefit of $2.5 million.

Pursuant to the provisions of the Stock Purchase Agreement, the buyer requested purchase price adjustments totaling $7.2 million. We contested this proposed adjustment and estimated the amount owed at $1.4 million, which is accrued in the loss from discontinued operations for the nine months ended Sept. 30, 2012. If we do not reach a negotiated agreement with the buyer regarding the purchase price adjustment, resolution will occur through the dispute resolution provision of the Stock Purchase Agreement.

Critical Accounting Policies

Except as noted below, there have been no material changes in our critical accounting policies from those reported in our 2011 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 2011 Annual Report on Form 10-K.

Full-Cost Method of Accounting for Oil and Gas Activities

As previously disclosed in our 2011 Annual Report filed in Form 10-K, we utilize the full-cost method of accounting for our oil and gas activities in accordance with SEC Rule 4-10 of Regulation S-X (Rule 4-10). Under the full-cost method, sales of oil and gas properties generally are recorded as an adjustment to capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between the capitalized costs and proved oil and gas reserves. The Company's Sept. 27, 2012 sale of oil and gas properties in the Williston Basin of North Dakota was significant as defined by Rule 4-10, and accordingly a $27.3 million pre-tax gain on sale was recorded. Total net cash proceeds from the sale were approximately $227 million.

Under the guidance of Rule 4-10, if a gain or loss is recognized on such a sale, total capitalized costs shall be allocated between the reserves sold and the reserves retained on the same basis used to compute amortization, unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs shall be allocated on the basis of the relative fair value of the properties in the cost center. Because of the substantial differences between the crude oil properties we sold and those properties retained, which were predominantly natural gas, we allocated based on relative fair values.

If a different method of allocating the capitalized costs was chosen, the gain recorded on our transaction could vary substantially. For example, if the allocation was made on the same basis used to compute amortization as noted within Rule 4-10 and we utilized the ratio of proven reserve quantities from the properties sold compared to total proven reserve quantities in our cost center, we would have recorded a gain on sale of approximately $160 million. Because of the value associated with the undeveloped acreage sold, we did not believe this was an appropriate methodology for allocation.

Any change in the gain recorded would impact the amount of adjustment to our capitalized costs therefore impacting our future depletion expense recorded within our financial statements.

Liquidity and Capital Resources

All amounts are presented on a pre-tax basis unless otherwise indicated.

Cash Flow Activities

The following table summarizes our cash flows for the nine months ended Sept. 30, 2012 and 2011 (in thousands):

Cash provided by (used in):	2012	2011	Increase (Decrease)
Operating activities	$269,667	$206,526	$63,141
Investing activities	$98,306	$(326,862)	$425,168
Financing activities	$(179,549)	$162,676	$(342,225)

Year-to-Date 2012 Compared to Year-to-Date 2011

Operating Activities

Net cash provided by operating activities was $63.1 million higher for the nine months ended Sept. 30, 2012 than for the same period in 2011 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $35.0 million higher for the nine months ended Sept. 30, 2012 than for the same period the prior year.

- Net inflows from operating assets and liabilities were $38.1 million for the nine months ended Sept. 30, 2012, an increase of $33.5 million from the same period in the prior year. In addition to other normal working capital changes, the increase primarily related to decreased gas volumes in inventory and lower natural gas prices.

- Cash contributions to the defined benefit pension plan were $25.0 million in 2012 compared to $11.0 million in 2011.

Investing Activities

Net cash provided by investing activities was $98.3 million in 2012 compared to net cash used by investing activities of $326.9 million in 2011 for a variance of $425.2 million. The variance was driven by cash proceeds from assets sold during 2012, including $243.3 million from the sale of 85 percent of our Williston Basin assets by our Oil and Gas segment, $25 million from the sale of a 50 percent ownership interest in the Busch Ranch Wind project, and $108.8 million for the sale of Enserco. Additionally, in 2012 we had reduced capital expenditures of $65.1 million due to the completion of construction of our Pueblo generation facility and $21.8 million note receivable for oil and gas properties.

Financing Activities

Net cash used in financing activities in 2012 was $179.5 million compared to net cash provided by financing activities in 2011 of $162.7 million for a variance of $342.2 million. The variance was driven by applying the proceeds from the sale of Enserco to pay down short-term borrowings on the Revolving Credit Facility of approximately $110 million while in the same period in the prior year we increased borrowings $210 million primarily to finance our construction program in Pueblo, Colo. Cash dividends on common stock of $48.9 million were paid in 2012 compared to cash dividends paid of $43.2 million in 2011. In addition, in May 2012 Black Hills Power repaid its Pollution Control Revenue Bonds for $6.5 million.

Dividends

Dividends paid on our common stock totaled $48.9 million for the nine months ended Sept. 30, 2012, or $1.11 per share. On Oct. 30, 2012, our board of directors declared a quarterly dividend of $0.37 per share payable Dec. 1, 2012, which is equivalent to an annual dividend rate of $1.48 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.

Financing Transactions and Short-Term Liquidity

Our principal sources of short-term liquidity are our Revolving Credit Facility and cash provided by operations. In addition to availability under our Revolving Credit Facility described below, as of Sept. 30, 2012 we had approximately $247 million of unrestricted cash included in Cash and cash equivalents on our Condensed Consolidated Balance Sheet resulting, in part, from the September 2012 sale of our Williston Basin assets. A portion of this cash was used on Oct. 31, 2012 to redeem our $225 million senior unsecured notes originally due in May 2013. In the first quarter of 2012, the net cash proceeds from the Enserco sale were utilized to reduce short-term debt on the Revolving Credit Facility by approximately $110 million.

Revolving Credit Facility

Our $500 million Revolving Credit Facility expiring Feb. 1, 2017 can be used for the issuance of letters of credit, to fund working capital needs and for general corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.50 percent, 1.50 percent and 1.50 percent, respectively. The facility contains a commitment fee that is charged on the unused amount of the facility. Based upon current credit ratings, the fee is 0.25 percent. The facility contains an accordion feature that allows us, with the consent of the administrative agent, to increase the capacity of the facility to $750 million.

At Sept. 30, 2012, we had borrowings of $75 million and letters of credit outstanding of $36 million on our Revolving Credit Facility. Available capacity remaining was approximately $389 million at Sept. 30, 2012.

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 a recourse leverage ratio not to exceed 0.65 to 1.00. At Sept. 30, 2012, our recourse leverage ratio as calculated under our Revolving Credit Facility was approximately 0.56 to 1.0. At Sept. 30, 2012, our long-term debt ratio was 46.2 percent and our total debt leverage ratio (long-term debt and short-term debt) was 55.2 percent.

In addition to covenant violations, an event of default under the Revolving Credit Facility may be triggered by other events, such as a failure to make payments when due or a failure to make payments when due in respect of, or a failure to perform obligations relating to, other debt obligations of $35 million or more. Subject to applicable cure periods (none of which apply to a failure to timely pay indebtedness), an event of default would permit the lenders to restrict our ability to further access the credit facility for loans and new letters of credit, and could require both the immediate repayment of any outstanding principal and interest and the cash collateralization of outstanding letter of credit obligations.

We were in compliance with the covenants and were not in default of the terms of the Revolving Credit Facility as of Sept. 30, 2012.

Short-Term Corporate Term Loan

In June 2012, we extended our one-year $150 million unsecured, single draw term loan for one year. The cost of borrowing under the extended loan now due on June 24, 2013 is based on a spread of 1.10 percent over LIBOR (1.35 percent at Sept. 30, 2012). The covenants are substantially the same as those included in the Revolving Credit Facility with an additional requirement to maintain a minimum consolidated net worth. We were in compliance with these covenants as of Sept. 30, 2012.

Long-term Corporate Term Loan

In December 2010, we entered into a one-year $100 million term loan with J.P. Morgan and Union Bank due in December 2011. On Sept. 30, 2011, we extended that term loan under the existing terms to Sept. 30, 2013. The cost of borrowing under this term loan is based on a spread of 1.375 percent over LIBOR (1.63 percent at Sept. 30, 2012). The covenants are substantially the same as those included in the Revolving Credit Facility with an additional requirement to maintain a minimum consolidated net worth. We were in compliance with these covenants as of Sept. 30, 2012.

Repayment of Long-term Debt

On Oct. 31, 2012, we redeemed our 6.5 percent senior unsecured notes originally due to mature on May 15, 2013 for $225.0 million plus interest and a one-time after-tax make whole-provision payment of $4.6 million.

On May 15, 2012, Black Hills Power repaid its 4.8 percent Pollution Control Revenue Bonds in full for $6.5 million including principal and interest. These bonds were originally due to mature on Oct. 1, 2014.

Dividend Restrictions

Certain of our debt agreements impose restrictions on our ability to pay dividends. Any determination to pay dividends in the future will be at the discretion of our Board of Directors and will depend upon our results of operations, financial condition, restrictions imposed by applicable law and our financing agreements and other factors that our Board of Directors deems relevant.

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 of certain statutory limitations or regulatory or financing agreements, we could have restrictions on the amount of distributions allowed to be made by our subsidiaries.

- Our utility subsidiaries are generally limited by state regulatory authorities in the amount of dividends allowed that they can pay the utility holding company and also may have further restrictions under the Federal Power Act. As of Sept. 30, 2012, the restricted net assets at our Electric and Gas Utilities were approximately $227.2 million.

- As required by the covenants in the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted equity of at least $100.0 million. In addition, Black Hills Wyoming holds $7.3 million of restricted cash associated with the project financing requirements.

Future Financing Plans

We have substantial future capital expenditures planned, which primarily include construction of additional utility generation to serve Black Hills Power and Cheyenne Light customers and meet governmental pollution control mandates and potential capital deployment in oil and gas drilling to prove-up reserves. Our capital requirements are expected to be financed through a combination of available cash, operating cash flows, borrowings on our Revolving Credit Facility, term loans and long-term financings and other debt or equity issuances.

After the repayment of our $225 million senior unsecured 6.5 percent notes originally due to mature in 2013 discussed above, we have term loans of $250 million expiring in 2013 and debt due of $250 million in 2014. With these upcoming financing requirements, we continue to evaluate various financing options that include senior unsecured notes, first mortgage bonds, term loans and project financing opportunities.

We intend to maintain a consolidated debt-to-capitalization level in the range of 50 percent to 55 percent; however, due to capital projects, we may exceed this level on a temporary basis. We anticipate that our existing credit capacity and available cash will be sufficient to fund our working capital needs and our maintenance capital requirements.

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 interest rate swaps with a notional amount of $250 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on these swaps are recorded within the Condensed Consolidated Statements of Income. For the three and nine months ended Sept. 30, 2012, respectively, we recorded $0.6 million pre-tax unrealized non-cash mark-to-market gain and $2.9 million pre-tax unrealized non-cash mark-to-market loss on the swaps. The mark-to-market value on these swaps was a liability of $95.6 million at Sept. 30, 2012. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A one basis point move in the interest rate curves over the term of the swaps would have a pre-tax impact of approximately $0.3 million. These swaps are for terms of 6.25 and 16.25 years and have early termination dates ranging from Dec. 15, 2012 to Dec. 16, 2013. We anticipate extending these agreements upon their early termination dates and have continued to maintain these swaps in anticipation of our upcoming financing needs. Alternatively, we may choose to cash settle these swaps at fair value prior to the early termination dates, or unless these dates are extended we will cash settle these swaps for an amount equal to their fair values on the termination dates.

In addition, we have $150 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of 4.3 years. These swaps have been designated as cash flow hedges, 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 $25.7 million at Sept. 30, 2012.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2011 Annual Report on Form 10-K filed with the SEC.

Credit Ratings

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing, and vendor payment terms including collateral requirements. As of Sept. 30, 2012, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

Rating Agency	Rating	Outlook
Fitch	BBB-	Stable
Moody's (a)	Baa3	Stable
S&P (a) (b)	BBB-	Stable

(a) In October 2012, both Moody's and S&P upgraded our outlook from Stable to Positive.
(b) In July 2012, S&P published its updated credit review, leaving our senior unsecured credit rating of BBB- and upgraded our risk profile from strong to excellent.

In addition, as of Sept. 30, 2012, Black Hills Power's first mortgage bonds were rated as follows:

Rating Agency	Rating	Outlook
Fitch	A-	Stable
Moody's (a)	A3	Stable
S&P (a)	BBB+	Stable

(a) In October 2012, both Moody's and S&P upgraded our outlook from Stable to Positive.

Capital Requirements

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

	Expenditures for the Nine Months Ended Sept. 30, 2012	Total 2012 Planned Expenditures	Total 2013 Planned Expenditures	Total 2014 Planned Expenditures
Utilities:				
Electric Utilities (1) (2)	$119,668	$163,500	$285,500	$216,000
Gas Utilities	31,982	52,000	56,000	57,600
Non-regulated Energy:				
Power Generation	5,122	7,400	4,200	6,800
Coal Mining	10,806	18,850	5,100	6,000
Oil and Gas (3)	88,223	97,200	98,300	84,300
Corporate	7,456	10,300	11,800	4,700
	$263,257	$349,250	$460,900	$375,400

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(1) Planned expenditures in 2012 and 2013 of $22 million and $27 million, respectively, for the proposed 88 MW of gas-fired generation at Colorado Electric have been removed from the forecasted expenditures reported in our 2011 Annual Report on Form 10-K as a result of the denial of our request for a CPCN. Additionally, capital expenditures required to comply with environmental regulations at Neil Simpson II have been removed.

(2) 2012 forecasted capital expenditures include a reduction of $25 million for the sale of 50 percent of the Busch Ranch Wind project.

(3) Capital expenditures at our Oil and Gas Segment are driven by economics and may vary depending on the pricing environment for crude oil and natural gas. Forecasted expenditures for 2012, 2013 and 2014 shown above for the Oil and Gas segment have been decreased from the amounts reported in our 2011 Annual Report on Form 10-K due to delaying our gas drilling program as a result of lower natural gas prices and the sale of the majority of our Williston Basin assets.

We continually evaluate all of our forecasted capital expenditures, and if determined prudent, we may defer some of these expenditures for a period of time. Future projects are dependent upon the availability of attractive economic opportunities, and as a result, actual expenditures may vary significantly from forecasted estimates.

Contractual Obligations

There have been no significant changes to contractual obligations or any off-balance sheet arrangements from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

Guarantees

There have been no significant changes to guarantees from those previously disclosed in Note 20 of our Notes to the Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the pronouncements reported in our 2011 Annual Report on Form 10-K filed with the SEC and those discussed in Note 2 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 statements.

FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking information. All statements, other than statements of historical fact, included in this report that address activities, events, or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. Forward-looking information involves risks and uncertainties, and certain important factors can cause actual results to differ materially from those anticipated. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. The factors which may cause our results to vary significantly from our forward-looking statements include the risk factors described in Item 1A of our 2011 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, and the following:

- Our ability to successfully resolve the purchase price adjustments in question from the sale of Enserco.

- We anticipate that our existing credit capacity, available cash and operating cash flows will be sufficient to fund our working capital needs and our maintenance capital requirements. Some important factors that could cause actual results to differ materially from those anticipated include:

- Our access to revolving credit capacity depends on maintaining compliance with loan covenants. If we violate these covenants, we may lose revolving credit capacity and therefore may not have sufficient cash available for our peak winter needs and other working capital requirements, and our forecasted capital expenditure requirements.

- Counterparties may default on their obligations to supply commodities, return collateral to us, or otherwise meet their obligations under commercial contracts, including those designed to hedge against movements in commodity prices.

- Capital market conditions and other economic or market uncertainties beyond our control may affect our ability to raise capital on favorable terms.

- We have term loans of $250 million expiring in 2013. In addition, we have senior unsecured bonds of $250 million due in 2014. We are evaluating financing options including senior notes, first mortgage bonds, term loans, project financing and equity issuance in the capital markets. Some important factors that could impact our ability to complete one or more of these financings include:

- Our ability to access the bank loan and debt and equity capital markets depends on market conditions beyond our control. If the capital markets deteriorate, we may not be able to refinance our short-term debt and fund our capital projects on reasonable terms, if at all.

- Our ability to raise capital in the debt capital markets depends upon our financial condition and credit ratings, among other things. If our financial condition deteriorates unexpectedly, or our credit ratings are lowered, we may not be able to refinance some short-term debt and fund our power generation projects on reasonable terms, if at all.

- We expect to make approximately $349.3 million, $460.9 million and $375.4 million of capital expenditures in 2012, 2013 and 2014, respectively. Some important factors that could cause actual expenditures to differ materially from those anticipated include:

- The timing of planned generation, transmission or distribution projects for our Utilities Group is influenced by state and federal regulatory authorities and third parties. The occurrence of events that impact (favorably or unfavorably) our ability to make planned or unplanned capital expenditures have caused and could cause our forecasted capital expenditures to change.

- Forecasted capital expenditures associated with our Oil and Gas segment are driven, in part, by current commodity prices, our ability to obtain permits, availability and costs of drilling and service equipment, and crews and other services, and our ability to negotiate agreements with property owners for land use. An inability to obtain permits, equipment or land use rights could delay drilling efforts. Our plans may also be negatively impacted by weather conditions and existing or proposed regulations, including possible hydraulic fracturing regulations.

- Our ability to complete the planning, permitting, construction, start-up and operation of power generation facilities in a cost-efficient and timely manner.

- We expect contributions to our defined benefit pension plans to be approximately $0.0 million and $4.5 million for the remainder of 2012 and for 2013, respectively. Some important factors that could cause actual contributions to differ materially from anticipated amounts include:

- The actual value of the plans' invested assets.

- The discount rate used in determining the funding requirement.

- We expect the goodwill related to our utility assets to fairly reflect the long-term value of stable, long-lived utility assets. Some important factors that could cause us to revisit the fair value of this goodwill include:

- A significant and sustained deterioration of the market value of our common stock.

- Negative regulatory orders, condemnation proceedings or other events that materially impact our Utilities Groups' ability to generate sufficient stable cash flow over an extended period of time.

- The effects of changes in the market including significant changes in the risk-adjusted discount rate or growth rates.

- The timing, volatility, and extent of changes in energy and commodity prices, supply or volume, the cost and availability of transportation of commodities, changes in interest rates, and the demand for our services, any of which can affect our earnings, our financial liquidity and the underlying value of our assets, including the possibility that we may be required to take future impairment charges under the SEC's full cost ceiling test for natural gas and crude oil reserves.

- Federal and state laws concerning climate change and air emissions, including emission reduction mandates, carbon emissions and renewable energy portfolio standards, may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain or which could mandate or require closure of one or more of our generating units.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

Our utility customers are exposed to the effect of volatile natural gas prices. We produce, purchase and distribute power in four states and purchase and distribute natural gas in five states, and we utilize natural gas as fuel at our Electric Utilities. All of our gas utilities have PGA provisions that allow them to pass the prudently-incurred cost of gas and services through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to true-up billed amounts to match the actual natural gas cost we incurred. These adjustments are subject to periodic prudence reviews by the state utility commissions. We have ECA mechanisms in South Dakota, Colorado, Wyoming and Montana for our electric utilities that serve a purpose similar to the PGAs for our gas utilities. To the extent that our fuel and purchased power energy costs and transmission costs are higher or lower than the energy cost built into our tariffs, the difference (or a portion thereof) is passed through to the customer.

As allowed or required by state utility commissions, we have entered into certain exchange-traded natural gas futures, options and basis swaps to reduce our customers' underlying exposure to the volatility of natural gas prices. These transactions are considered derivatives and are marked-to-market. Gains or losses, as well as option premiums on these transactions, are recorded in Regulatory assets or Regulatory liabilities. Once settled, the gains and losses are passed on to our customers through the PGA.

The fair value of our Utilities Group's derivative contracts is summarized below (in thousands) as of:

	Sept. 30, 2012	Dec. 31, 2011	Sept. 30, 2011
Net derivative (liabilities) assets	$(7,253)	$(16,676)	$(10,064)
Cash collateral	15,740	19,416	12,058
	$8,487	$2,740	$1,994

Oil and Gas Activities

We have entered into agreements to hedge a portion of our estimated 2012, 2013 and 2014 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at Sept. 30, 2012 were as follows:

Natural Gas

	For the Three Months Ended				
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total Year
2012					
Swaps - MMBtu				1,196,000	1,196,000
Weighted Average Price per MMBtu				$3.74	$3.74
2013					
Swaps - MMBtu	1,220,000	1,233,000	1,246,000	1,155,250	4,854,250
Weighted Average Price per MMBtu	$4.01	$3.55	$3.33	$3.51	$3.60
2014					
Swaps - MMBtu	950,000	455,000			1,405,000
Weighted Average Price per MMBtu	$3.71	$3.45			$3.63

Crude Oil

	For the Three Months Ended				
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total Year
2012					
Swaps - Bbls				42,000	42,000
Weighted Average Price per Bbl				$97.99	$97.99
Puts - Bbls				21,000	21,000
Weighted Average Price per Bbl				$76.43	$76.43
Calls - Bbls				21,000	21,000
Weighted Average Price per Bbl				$95.00	$95.00
2013					
Swaps - Bbls	30,000	21,000	15,000	15,000	81,000
Weighted Average Price per Bbl	$101.62	$108.96	$110.20	$101.75	$105.13
Puts - Bbls	30,000	36,000	39,000	36,000	141,000
Weighted Average Price per Bbl	$76.75	$78.96	$79.81	$80.63	$79.15
Calls - Bbls	30,000	36,000	39,000	36,000	141,000
Weighted Average Price per Bbl	$96.50	$97.17	$97.08	$97.25	$97.02
2014					
Swaps - Bbls	45,000	45,000			90,000
Weighted Average Price per Bbl	$94.38	$90.82			$92.60

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. As of Sept. 30, 2012, we had $150 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 4.25 years. These swaps have been designated as hedges in accordance with accounting standards for derivatives and hedges and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive income (loss) on the Condensed Consolidated Balance Sheets.

We also have interest rate swaps with a notional amount of $250 million, which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were originally designated as cash flow hedges and the mark-to-market value was recorded in Accumulated other comprehensive income (loss) on the Condensed Consolidated Balance Sheets. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and, as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the Condensed Consolidated Statements of Income. For the three months and nine months ended Sept. 30, 2012, we recorded pre-tax unrealized non-cash mark-to-market gain of $0.6 million and a pre-tax unrealized non-cash mark-to-market loss of $2.9 million, respectively. For the three months and nine months ended Sept. 30, 2011, we recorded pre-tax unrealized non-cash mark-to-market losses of $38.2 million and $40.6 million, respectively. The mark-to-market value on these swaps was a liability of $95.6 million at Sept. 30, 2012. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A one basis point move in the interest rate curves over the term would have a pre-tax impact of approximately $0.3 million. These swaps are 6.25 and 16.25 year swaps which have early termination dates ranging from Dec. 15, 2012 to Dec. 16, 2013.

We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly our upcoming holding company debt maturities. Alternatively, we may choose to cash settle these swaps at fair value prior to the early termination dates, or unless these dates are extended we will cash settle these swaps for an amount equal to their fair values on the stated termination dates.

Further details of the swap agreements are set forth in Note 11 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Our interest rate swaps and related balances were as follows (dollars in thousands) as of:

	Sept. 30, 2012		Dec. 31, 2011		Sept. 30, 2011	
	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*
Notional	$150,000	$ 250,000	$150,000	$ 250,000	$150,000	$ 250,000
Weighted average fixed interest rate	5.04 %	5.67 %	5.04 %	5.67 %	5.04 %	5.67 %
Maximum terms in years	4.25	1.25	5.00	2.00	5.25	0.25
Derivative liabilities, current	$7,028	$ 77,914	$6,513	$ 75,295	$6,724	$ 94,588
Derivative liabilities, non-current	$18,660	$ 17,668	$20,363	$ 20,696	$21,108	$ —
Pre-tax accumulated other comprehensive loss included in Condensed Consolidated Balance Sheets	$(25,688)	$ —	$(26,876)	$ —	$(27,832)	$ —
Pre-tax (loss) gain included in Condensed Consolidated Statements of Income	$—	$ (2,902)	$—	$ (42,010)	$—	$ (40,608)
Cash collateral receivable (payable) included in accounts receivable	$—	$ 3,310	$—	$ —	$—	$ —

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* Maximum terms in years for our de-designated interest rate swaps reflect the amended early termination dates. If the early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date. When extended annually, de-designated swaps totaling $100 million terminate in 6.25 years and de-designated swaps totaling $150 million terminate in 16.25 years.

Based on Sept. 30, 2012 market interest rates and balances for our designated interest rate swaps, a loss of approximately $7.0 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will change during the next 12 months as market interest rates change.

Collateral requirements based on our corporate credit rating apply to $50 million of our de-designated swaps. At our current credit ratings, we are required to post collateral for any amount by which the swaps' negative mark-to-market fair value exceeds $20 million. If our senior unsecured credit rating drops to BB+ or below by S&P, or to Ba1 or below by Moody's, we would be required to post collateral for the entire amount of the swaps' negative mark-to-market fair value.

ITEM 4. CONTROLS AND PROCEDURES

This section should be read in conjunction with Item 9A, "Controls and Procedures" included in our Annual Report on Form 10-K for the year ended Dec. 31, 2011.

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 (Exchange Act)) as of Sept. 30, 2012 and concluded that, because of the material weakness in our internal control over financial reporting related to accounting for income taxes as previously disclosed in Item 9A, “Controls and Procedures” in our Annual Report on Form 10-K for the year ended Dec. 31, 2011, our disclosure controls and procedures were not effective as of Sept. 30, 2012. Additional review, evaluation and oversight have been undertaken to ensure our unaudited Condensed Consolidated Financial Statements were prepared in accordance with generally accepted accounting principles and as a result, our management, including our Chief Executive Officer and Chief Financial Officer, have concluded that the Condensed Consolidated Financial Statements in this Form 10-Q fairly present in all material respects our financial position, results of operations and cash flows for the periods presented in conformity with accounting principles generally accepted in the United States.

As discussed in our 2011 Annual Report on Form 10-K, management concluded that while we had appropriately designed control procedures for income tax accounting and disclosures, the existence of non-routine transactions, insufficient tax resources, and ineffective communications between the tax department and Controller organization caused us to poorly execute the controls for evaluating and recording income taxes. Management has developed and implemented a remediation plan to address this material weakness in internal controls surrounding accounting for income taxes. Key aspects of the remediation plan include enhanced resources and skill sets, and implementation of formal periodic meetings among the Chief Financial Officer, Controller and the tax department.

While we concluded our internal controls surrounding income taxes were not effective as of Sept. 30, 2012, we are remediating the material weakness and will continue to execute our remediation plan and track our performance against the plan.

During the quarter ended Sept. 30, 2012, there have been no other 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 19 in Item 8 of our 2011 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

There are no material changes to the Risk Factors previously disclosed in Item 1A of Part I in our Annual Report on Form 10-K for the year ended Dec. 31, 2011.

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

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans for Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2012 - July 31, 2012	—	$—	—	—
Aug. 1, 2012 - Aug. 31, 2012	262	$31.46	—	—
Sept. 1, 2012 - Sept. 30, 2012	—	$—	—	—
Total	262	$31.46	—	—

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(1) Shares were acquired from certain officers and key employees under the share withholding provisions of the Omnibus Incentive Plan for the payment of taxes associated with the vesting of shares of restricted stock.

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 2	Purchase and Sale Agreement, dated as of August 23, 2012, by and among Black Hills Exploration and Production, Inc. and Other Sellers and QEP Energy Company, as Purchaser (excluding exhibits and certain schedules, which the Registrant agrees to furnish supplementally to the Securities and Exchange Commission upon request).
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

BLACK HILLS CORPORATION

Signatures

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

BLACK HILLS CORPORATION

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

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

Dated: November 8, 2012

EXHIBIT INDEX

Exhibit Number	Description
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