BLACK HILLS CORP /SD/
Form 10-Q
August 10, 2009

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2009.

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 o No o

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

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

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

Yes o No x

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

Class	Outstanding at July 31, 2009
Common stock, $1.00 par value	38,842,133 shares

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

Acquisition Facility	Our $1.0 billion single-draw, senior unsecured facility from which a $383 million draw was used to provide part of the funding for our Aquila Transaction
AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
ARB	Accounting Research Bulletin
ARB 51	ARB 51, Consolidated Financial Statements
Aquila	Aquila, Inc.
Aquila Transaction	Our July 14, 2008 acquisition of Aquila s regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa
Bbl	Barrel
BHCRPP	Black Hills Corporation Risk Policies and Procedures
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business activities of Black Hills Utility Holdings, including the gas and electric utility properties acquired from Aquila
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of the Company that was formerly known as Black Hills Energy, Inc.
Black Hills Power	Black Hills Power, Inc., 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 formed to acquire and own the utility properties acquired from Aquila, all which are now doing business as Black Hills Energy
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company
Cheyenne Light Pension Plan	The Cheyenne Light, Fuel and Power Company Pension Plan
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, formed to hold the Colorado electric utility properties acquired from Aquila
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, formed to hold the Colorado gas utility properties acquired from Aquila
Corporate Credit Facility	Our unsecured $525 million revolving line of credit
CPUC	Colorado Public Utilities Commission
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)

EITF	Emerging Issues Task Force
EITF 02-3	EITF Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities
EITF 87-24	EITF Issue No. 87-24, Allocation of Interest to Discontinued Operations
EITF 99-2	EITF Issue No. 99-2, Accounting for Weather Derivatives
Enserco	Enserco Energy Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretations
FIN 39	FIN 39, Offsetting of Amounts Related to Certain Contracts an Interpretation of APB Opinion No. 10 and FASB Statement No. 105
FIN 46(R)	FIN 46-(R), Consolidation of Variable Interest Entities (Revised December 2003) an interpretation of ARB No. 51
FSP	FASB Staff Position
FSP EITF 03-6-1	FSP EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities
FSP FAS 107-1	FSP FAS 107-1, Interim Disclosure About Fair Value of Financial Instruments
FSP FAS 132(R)-1	FSP FAS 132(R)-1, Employer s Disclosures about Pensions and Other Postretirement Benefits (Revised)
FSP FAS 157-4	FSP FAS 157-4, Determining Whether a Market is Not Active and a Transaction is Not Distressed
FSP FIN 39-1	FSP FIN 39-1, Amendment of FASB Interpretation No. 39
GAAP	Generally Accepted Accounting Principles
GE	GE Packaged Power, Inc.
GSRS	Gas Safety and Reliability Surcharge
Hastings	Hastings Funds Management Ltd
IIF	IIF BH Investment LLC, a subsidiary of an investment entity advised by JPMorgan Asset Management
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, formed to hold the Iowa gas utility properties acquired from Aquila
IPP	Independent Power Production
IPP Transaction	Our July 11, 2008 sale of seven of our IPP plants to affiliates of Hastings and IIF
IUB	Iowa Utilities Board
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Kansas gas utility properties acquired from Aquila
KCC	Kansas Corporation Commission
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	One thousand cubic feet

Mcfe	One thousand cubic feet equivalent
MDU	MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MMBtu	One million British thermal units
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, formed to hold the Nebraska gas utility properties acquired from Aquila
NPA	Nebraska Public Advocate
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
OCA	Office of Consumer Advocate
PGA	Purchase Gas Adjustment
PPA	Power Purchase Agreement
PSCo	Public Service Company of Colorado
SEC	United States Securities and Exchange Commission
SEC Release No. 33-8995	SEC Release No. 33-8995, Modernization of Oil and Gas Reporting
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS 71, Accounting for the Effects of Certain Types of Regulation
SFAS 133	SFAS 133, Accounting for Derivative Instruments and Hedging Activities
SFAS 141(R)	SFAS 141(R), Business Combinations
SFAS 142	SFAS 142, Goodwill and Other Intangible Assets
SFAS 144	SFAS 144, Accounting for the Impairment or Disposal of Long-lived Assets
SFAS 157	SFAS 157, Fair Value Measurements
SFAS 160	SFAS 160, Non-controlling Interest in Consolidated Financial Statements an amendment of ARB No. 51
SFAS 161	SFAS 161, Disclosure about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133
SFAS 165	SFAS 165, Subsequent Events
SFAS 167	SFAS 167, Amendment to FASB Interpretation No. 46(R)
SFAS 168	SFAS 168, FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Standard No. 162
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, LLC

BLACK HILLS CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in thousands, except per share amounts)			
Operating revenues	$ 257,349	$ 153,273	$ 695,292	$ 306,123
Operating expenses:				
Fuel and purchased power	112,169	46,948	373,189	99,343
Operations and maintenance	40,461	24,320	79,795	46,285
Gain on sale of assets			(25,971)	
Administrative and general	37,708	25,222	79,474	49,281
Depreciation, depletion and amortization	29,386	20,788	62,712	40,174
Taxes, other than income taxes	11,811	10,472	23,509	19,980
Impairment of long-lived assets			43,301	
	231,535	127,750	636,009	255,063
Operating income	25,814	25,523	59,283	51,060
Other income (expense):				
Interest expense	(23,338)	(9,564)	(42,239)	(18,758)
Interest rate swap unrealized gain	31,706		46,469	
Interest income	329	373	856	799
Allowance for funds used during construction equity	1,314	617	2,686	898
Other income, net	893	65	1,637	400
	10,904	(8,509)	9,409	(16,661)
Income from continuing operations before equity in earnings of unconsolidated subsidiaries and income taxes	36,718	17,014	68,692	34,399
Equity in earnings of unconsolidated subsidiaries	1,576	2,064	1,249	2,297
Income tax expense	(13,713)	(5,875)	(19,735)	(11,676)
Income from continuing operations	24,581	13,203	50,206	25,020
Income from discontinued operations, net of taxes		9,046	766	14,098
Net income	24,581	22,249	50,972	39,118
Net loss attributable to non - controlling interest		(53)		(130)
Net income available for common stock	$ 24,581	$ 22,196	$ 50,972	$ 38,988
Weighted average common shares outstanding:				
Basic	38,598	38,299	38,554	38,062
Diluted	38,658	38,425	38,611	38,412
Earnings per share:				
Basic				
Continuing operations	$ 0.64	$ 0.34	$ 1.30	$ 0.65
Discontinued operations		0.24	0.02	0.37
Total	$ 0.64	$ 0.58	$ 1.32	$ 1.02
Diluted				
Continuing operations	$ 0.64	$ 0.34	$ 1.30	$ 0.65
Discontinued operations		0.24	0.02	0.36

Total	$ 0.64	$ 0.58	$ 1.32	$ 1.01
Dividends paid per share of common stock	$ 0.355	$ 0.350	$ 0.710	$ 0.700

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)

	June 30, 2009	December 31, 2008	June 30, 2008
	(in thousands, except share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 122,351	$ 168,491	$ 36,912
Restricted cash			5,498
Short-term investments			7,309
Receivables (net of allowance for doubtful accounts of $7,010; $6,751 and $3,417, respectively)	181,250	357,404	252,508
Materials, supplies and fuel	88,672	118,021	147,169
Derivative assets	75,600	73,068	70,769
Income tax receivable, net		20,269	
Deferred income taxes	17,640	10,244	20,674
Regulatory assets	14,086	35,390	3,402
Other current assets	31,917	16,380	12,283
Assets of discontinued operations		246	598,294
	531,516	799,513	1,154,818
Investments	20,316	22,764	18,782
Property, plant and equipment	2,819,510	2,705,492	1,972,489
Less accumulated depreciation and depletion	(773,278)	(683,332)	(544,018)
	2,046,232	2,022,160	1,428,471
Other assets:			
Goodwill	359,288	359,290	14,000
Intangible assets, net	4,784	4,884	
Derivative assets	5,029	9,799	14,042
Regulatory assets	133,386	143,705	18,413
Other	11,189	17,774	13,708
	513,676	535,452	60,163
	$ 3,111,740	$ 3,379,889	$ 2,662,234
LIABILITIES AND STOCKHOLDERS EQUITY			
Current liabilities:			
Accounts payable	$ 175,190	$ 288,907	$ 269,095
Accrued liabilities	133,291	134,940	87,099
Derivative liabilities	69,347	118,657	89,790
Accrued income taxes, net	27,152		4,601
Regulatory liabilities	36,943	5,203	3,865
Notes payable	270,500	703,800	283,000
Current maturities of long-term debt	32,086	2,078	2,070
Liabilities of discontinued operations		88	77,202
	744,509	1,253,673	816,722
Long-term debt, net of current maturities	719,243	501,252	501,301
Deferred credits and other liabilities:			
Deferred income taxes	233,592	223,607	218,104
Derivative liabilities	12,098	22,025	23,158
Regulatory liabilities	39,967	38,456	30,448
Benefit plan liabilities	160,712	159,034	43,337
Other	121,519	131,306	60,447
	567,888	574,428	375,494
Stockholders equity:			
Common stock equity			
Common stock $1 par value; 100,000,000 shares authorized; Issued 38,836,918; 38,676,054 and 38,439,339 shares, respectively	38,837	38,676	38,439
Additional paid-in capital	586,879	584,582	579,725
Retained earnings	470,883	447,453	409,651
Treasury stock at cost 3,549; 40,183 and 31,604			

shares, respectively	(84)	(1,392)	(1,132)
Accumulated other comprehensive loss	(16,415)	(18,783)	(58,098)
Total common stockholders equity	1,080,100	1,050,536	968,585
Non-controlling interest in subsidiaries			132
Total equity	1,080,100	1,050,536	968,717
	$ 3,111,740	$ 3,379,889	$ 2,662,234

The accompanying notes to condensed consolidated financial statements are an integral part of these condensed consolidated financial statements.

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BLACK HILLS CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

	Six Months Ended June 30, 2009	2008
	(in thousands)	
Operating activities:		
Net income	$ 50,972	$ 39,118
Income from discontinued operations, net of taxes	(766)	(14,098)
Income from continuing operations	50,206	25,020
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	62,712	40,174
Impairment of long-lived assets	43,301	
Derivative fair value adjustments	12,780	(515)
Gain on sale of operating assets	(25,971)	
Unrealized mark-to-market gain on interest rate swaps	(46,469)	
Deferred income taxes	(21)	14,827
Distributed (undistributed) earnings of associated companies	3,234	(655)
Allowance for funds used during construction equity	(2,686)	(898)
Change in operating assets and liabilities:		
Materials, supplies and fuel	31,938	(42,490)
Accounts receivable and other current assets	164,718	(32,520)
Accounts payable and other current liabilities	(112,073)	22,963
Regulatory assets and liabilities	62,562	(1,900)
Other operating activities	1,126	(5,859)
Net cash provided by operating activities of continuing operations	245,357	18,147
Net cash provided by operating activities of discontinued operations	883	23,113
Net cash provided by operating activities	246,240	41,260
Investing activities:		
Property, plant and equipment additions	(163,608)	(127,036)
Proceeds from sale of ownership interest in plants	84,199	
Working capital adjustment of purchase price allocation on Aquila acquisition	7,658	
Purchase of short-term investments		(7,475)
Other investing activities	(4,963)	994
Net cash used in investing activities of continuing operations	(76,714)	(133,517)
Net cash used in investing activities of discontinued operations		(33,375)
Net cash used in investing activities	(76,714)	(166,892)
Financing activities:		
Dividends paid	(27,542)	(26,730)
Common stock issued	1,553	2,384
(Decrease) increase in short-term borrowings, net	(433,300)	246,000
Long-term debt issuances	248,500	
Long-term debt repayments	(2,001)	(130,256)
Other financing activities	(2,917)	215
Net cash (used in) provided by financing activities of continuing operations	(215,707)	91,613
Net cash used in financing activities of discontinued operations		(6,428)
Net cash (used in) provided by financing activities	(215,707)	85,185
Decrease in cash and cash equivalents	(46,181)	(40,447)
Cash and cash equivalents:		
Beginning of period	168,532 [a]	81,255 [c]
End of period	$ 122,351	$ 40,808 [b]
Supplemental disclosure of cash flow information:		
Non-cash investing and financing activities-		
Property, plant and equipment acquired with accrued liabilities	$ 40,053	$ 20,053
Cash paid during the period for-		
Interest (net of amounts capitalized)	$ 41,969	$ 18,665

Income taxes paid (net of amounts refunded)	$	(23,861)	$	2,293

(a) Includes less than $0.1 million of cash included in the assets of discontinued operations.
(b) Includes approximately $3.9 million of cash included in the assets of discontinued operations.
(c) Includes approximately $4.4 million of cash included in the assets of discontinued operations.

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 2008 Annual Report on Form 10-K)

(1) MANAGEMENT S STATEMENT

The condensed consolidated financial statements included herein have been prepared by Black Hills Corporation (the Company, us, we, our) without audit, 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 quarterly financial statements should be read in conjunction with the financial statements and the notes thereto, included in our 2008 Annual Report on Form 10-K filed with the SEC. These financial statements include consideration of events through August 10, 2009.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying condensed quarterly financial statements reflects all adjustments which are, in the opinion of management, necessary for a fair presentation of the June 30, 2009, December 31, 2008 and June 30, 2008 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal and revenues 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 six months ended June 30, 2009, and our financial condition as of June 30, 2009 and December 31, 2008, 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 July 11, 2008, we completed the sale of seven of our IPP plants. Amounts associated with the IPP plants divested in the IPP Transaction have been reclassified as discontinued operations for the quarter ended June 30, 2008. See Note 18 for additional information.

On July 14, 2008, we completed the acquisition of a regulated electric utility in Colorado and regulated gas utilities in Colorado, Kansas, Nebraska and Iowa from Aquila. Effective as of that date, the assets and liabilities, results of operations, and cash flows of the acquired utilities are included in our Condensed Consolidated Financial Statements. See Note 16 for additional information.

(2) RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

SFAS 141(R)

In December 2007, the FASB issued SFAS 141(R). SFAS 141(R) requires an acquiring entity to recognize the assets acquired, the liabilities assumed and any non-controlling interests in the acquiree at the acquisition date to be measured at their fair values as of the acquisition date, with limited exceptions specified in the statement. Acquisition-related costs will be expensed in the periods in which the costs are incurred or services are rendered. If income tax liabilities were settled for an amount other than as previously recorded prior to the adoption of SFAS 141(R), the reversal of any remaining liability would have affected goodwill. If such liabilities reverse subsequent to the adoption of SFAS 141(R), such reversals will affect expense including income tax expense in the period of reversal. Costs to issue debt or equity securities shall be accounted for under other applicable GAAP. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after December 15, 2008. We adopted SFAS 141(R) on January 1, 2009. Any impact that SFAS 141(R) will have on our consolidated financial statements will depend on the nature and magnitude of any future acquisitions we consummate and the resolution of certain tax contingencies.

SFAS 157

During September 2006, the FASB issued SFAS 157. This Statement defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 does not expand the application of fair value accounting to any new circumstances, but applies the framework to other accounting pronouncements that require or permit fair value measurement. We apply fair value measurements to certain assets and liabilities, primarily commodity derivatives within our Energy Marketing and Oil and Gas segments, interest rate swap instruments, and other miscellaneous derivatives.

As a result of the adoption of SFAS 157 on January 1, 2008, we discontinued our use of a liquidity reserve in valuing the total forward positions within our energy marketing portfolio. This impact was accounted for prospectively as a change in accounting estimate and resulted in a $1.2 million after-tax benefit that was recorded within our unrealized marketing margins. Unrealized margins are presented as a component of Operating revenues on the accompanying Condensed Consolidated Statements of Income. SFAS 157 also required new disclosures regarding the level of pricing observability associated with instruments carried at fair value. These disclosures are provided in Note 14.

SFAS 160

In December 2007, the FASB issued SFAS No. 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the non-controlling interest, changes in a parent s ownership interest, and the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. This statement was effective for us beginning January 1, 2009.

We applied the provisions of SFAS 160 on January 1, 2009. Non-controlling interest in the accompanying Condensed Consolidated Statements of Income and Balance Sheets represents the non-affiliated equity investors interest in Wygen Funding LP, a Variable Interest Entity as defined by FIN 46(R). In June 2008, we purchased the non-controlling share. Presentation of a non-controlling interest that we held until June 2008 was retrospectively applied as required, and had an immaterial overall effect.

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SFAS 161

In March 2008, the FASB issued SFAS 161, which requires enhanced disclosures about derivative and hedging activities and their affect on an entity s financial position, financial performance and cash flows. SFAS 161 encourages, but does not require, disclosures for earlier periods presented for comparative purposes at initial adoption. SFAS 161 requires comparative disclosures only for periods subsequent to its initial adoption. We adopted the provisions of SFAS 161 on January 1, 2009. The additional disclosures are provided in Note 12 and Note 13.

SFAS 165

In May 2009, the FASB issued SFAS 165, which establishes general standards of accounting for and disclosures of events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. We adopted and applied the provisions of SFAS 165 for our financial statements issued after June 15, 2009.

FSP FAS 107-1

In April 2009, the FASB approved FSP FAS 107-1 effective for interim and annual periods ending after June 15, 2009. This FSP requires public companies to provide more frequent disclosures about the fair value of their financial instruments. These disclosures are included in Note 14.

FSP FAS 157-4

In April 2009, the FASB approved FSP FAS 157-4 effective for interim and annual periods ending after June 15, 2009. This FSP amends FAS 157 which addresses inactive markets. This FSP includes a two step model with the first step determining whether factors exist that indicate a market for an asset is not active. If step one results in the conclusion that there is not an active market, step two evaluates whether the quoted price is not associated with a distressed transaction. Additional disclosures required include interim disclosure of valuation techniques. The adopted FSP FAS 157-4 had no overall effect on our financial statements and any additional disclosures are included in Note 14.

FSP EITF 03-6-1

In June 2008, the FASB issued FSP EITF 03-6-1 which states that unvested share-based payment awards that contain non-forfeitable rights to dividends are participating securities as defined under EITF 03-6 and therefore should be included in computing EPS using the two-class method. The two-class method is an earnings allocation method for computing EPS and determines EPS based on dividends declared on common stock and participating securities in any undistributed earnings. We adopted FSP EITF 03-6-1 on January 1, 2009. We prepared our current and prior period EPS computation in accordance with FSP EITF 03-6-1, and there was no impact on our EPS as a result of the adoption.

(3) RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

SEC Release No. 33-8995

On December 29, 2008, the SEC issued Release No. 33-8995, amending the existing Regulation S-K and Regulation S-X requirements for reporting the quantity and value of oil and gas reserves to align with current industry practices and technology advances. Key revisions include the ability to include non-traditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves. Companies must use a 12-month average price. The average is calculated using unweighted average of the first-day-of-the-month price for each of the 12 months that make up the reporting period. The amendment is effective for annual reporting periods ending on December 31, 2009, and early adoption is prohibited. We are currently assessing the impact that the adoption will have on our disclosures, operating results, financial position and cash flows.

SFAS 167

In June 2009, the FASB issued SFAS 167, a revision to FASB Interpretation No. 46(R). This Statement amends the analysis performed by a Company in determining whether an entity that is insufficiently capitalized or is not controlled through voting should be consolidated. It will require additional disclosures about the involvement with variable interest entities and any significant changes in risk exposure due to that involvement. This Statement is effective for annual periods that begin after November 15, 2009. We are currently assessing the impact that the adoption of this Statement will have on our financial condition, results of operations, and cash flows.

SFAS 168

On July 1, 2009, the FASB Accounting Standards Codification™ will become the source of authoritative GAAP recognized by the FASB to be applied by non-governmental entities. On the effective date of this Statement, the Codification will supersede all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in the Codification will become non-authoritative. This Statement is effective for financial statements issued for interim and annual periods ending after September 15, 2009. We will update GAAP references for financial statements issued after September 15, 2009.

Following this Statement, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Task Force Abstracts. Instead, it will issue Accounting Standards Updates. The FASB will not consider Accounting Standards Updates as authoritative in their own right. Accounting Standards Updates will serve only to update the Codification, provide background information about the guidance, and provide the basis for conclusions on the change(s) in the Codification.

FSP FAS 132(R)-1

During December 2008, the FASB issued FSP FAS 132(R)-1, which provides guidance on an employer s disclosures about plan assets in a defined benefit pension or other postretirement plan to provide users of financial statements with an understanding of:

How investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies;

The major categories of plan assets;

The input and valuation techniques used to measure the fair value of plan assets;

The effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and

Significant concentrations of risk within plan assets.

FSP FAS 132(R)-1 is effective for fiscal years ending after December 15, 2009. We do not expect the adoption of FSP FAS 132(R)-1 to have a significant effect on our consolidated financial statements.

(4) MATERIALS, SUPPLIES AND FUEL

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

Major Classification	June 30, 2009	December 31, 2008	June 30, 2008
Materials and supplies	$ 32,145	$ 32,580	$ 28,350
Fuel Electric Utilities	7,264	10,058	6,098
Natural gas in storage Gas Utilities	13,109	59,529	
Gas and oil held by Energy Marketing*	36,154	15,854	112,721
Total materials, supplies and fuel	$ 88,672	$ 118,021	$ 147,169

* As of June 30, 2009, December 31, 2008 and June 30, 2008, market adjustments related to natural gas held by Energy Marketing and recorded in inventory were $(3.8) million, $(9.4) million and $6.3 million, respectively (see Note 12 for further discussion of Energy Marketing trading activities).

Gas and oil inventory held by Energy Marketing primarily consists of gas held in storage. Such gas is being held in inventory to capture the price differential between the time at which it was purchased and a subsequent sales date in the future.

(5) NOTES PAYABLE AND LONG-TERM DEBT

Public Debt Offering

On May 14, 2009, we issued a $250 million aggregate principal amount of senior unsecured notes due in 2014 pursuant to a public offering. The notes were priced at par and carry a fixed interest rate of 9%. We received proceeds of $248.5 million, net of underwriting fees. Proceeds were used to pay down the Acquisition Facility. Estimated deferred financing costs related to the offering of $2.2 million were capitalized and will be amortized over the life of the debt. Amortization expense for the three months ended June 30, 2009 was approximately $0.1 million.

Acquisition Facility

In May 2007, we entered into a senior unsecured $1 billion Acquisition Facility with ABN AMRO Bank N.V., as administrative agent, and other banks to fund the Aquila Transaction. On July 14, 2008, in conjunction with the completion of the purchase of the Aquila properties, we executed a single draw of $382.8 million under the Acquisition Facility. The loan was originally scheduled to mature on February 5, 2009. However, on December 18, 2008, we amended the facility to extend the maturity date to December 29, 2009. The Acquisition Facility was repaid in the second quarter of 2009 using: (1) net proceeds from the sale of a 25% ownership interest in the Wygen III plant of $30.2 million; (2) proceeds from the $250 million public debt offering; and (3) $104.6 million from borrowings under the Corporate Credit Facility. Amortization expense for the three and six months ended June 30, 2009 was $0.7 million and $1.9 million, respectively. The remaining balance of $2.9 million of deferred financing costs was written off as Interest expense on the accompanying Condensed Consolidated Statements of Income as the loan was repaid.

Enserco Credit Facility

On May 8, 2009, Enserco entered into an agreement for a $240 million committed credit facility. Societe Generale, Fortis Capital Corp., and BNP Paribas were co-lead arranger banks. On May 27, 2009, Enserco entered into an agreement for an additional $60 million of Commitments under the credit facility with three new participating banks: Calyon, Rabobank and RZB Finance. This credit facility expires on May 7, 2010. The facility is a borrowing rate line of credit, which allows for the issuance of letters of credit and for borrowings. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. The base rate option borrowing rate is 2.75% plus the higher of: (i) 0.5% above the Federal Funds Rate, or (ii) the prime rate established by Fortis Bank S.A./N.V. The Eurodollar option borrowing rate is 2.75% plus the higher of the Eurodollar Rate or the reference bank cost of funds. Our Enserco credit facility is a borrowing base credit facility, the structure of which requires certain levels of tangible net worth and net working capital to be maintained for a given borrowing base election level. In order to maintain a borrowing base election level, we may be restricted from making dividends from Enserco to the parent company of Enserco. At June 30, 2009, $73.6 million of letters of credit were issued and outstanding under this facility and there were no cash borrowings outstanding. Deferred financing costs of $1.9 million were capitalized and will be amortized over the life of the facility.

(6) GUARANTEES

Guarantees with GE

We issued two guarantees for up to $37.9 million each to GE for payment obligations arising from a contract to purchase two LMS100 natural gas turbine generators by Colorado Electric, which are expected to be used in meeting a portion of the capacity and energy needs of our Colorado Electric customers. They are continuing guarantees which terminate upon payment in full of the purchase price to GE. Payments are scheduled based upon estimated construction milestone dates with the final payment due October 27, 2010.

Guarantees to MEAN

On January 20, 2009, we guaranteed a surety bond for $9.2 million to MEAN to secure operating performance obligations related to the Wygen I ownership agreement. Black Hills Wyoming and MEAN entered into the ownership agreement when MEAN acquired a 23.5% ownership interest in the Wygen I plant. The surety bond expires on December 31, 2009.

(7) EARNINGS PER SHARE

Basic earnings per share from continuing operations is computed by dividing income from continuing operations by the weighted-average number of common shares outstanding during the period. Diluted earnings per share from continuing operations gives effect to all dilutive common shares potentially outstanding during a period. A reconciliation of Income from continuing operations and basic and diluted share amounts is as follows (in thousands):

Period ended June 30, 2009	Three Months		Six Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 24,581		$ 50,206	
Basic earnings	24,581	38,598	50,206	38,554
Dilutive effect of:				
Restricted stock		60		57
Diluted earnings	$ 24,581	38,658	$ 50,206	38,611

Period ended June 30, 2008	Three Months		Six Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 13,203		$ 25,020	
Basic earnings	13,203	38,299	25,020	38,062
Dilutive effect of:				
Stock options		62		71
Estimated contingent shares issuable for prior acquisition				198

Restricted stock		61		69
Others		3		12
Diluted earnings	$ 13,203	38,425	$ 25,020	38,412

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

	Three Months Ended June30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Options to purchase common stock	435	78	435	78

(8) OTHER COMPREHENSIVE INCOME

The following table presents the components of our other comprehensive income

(in thousands):

	Three Months Ended June 30,	
	2009	2008
Net income	$ 24,581	$ 22,249
Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $4,072 and $5,510, respectively)	(7,793)	(10,359)
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $(2,143) and $(2,261), respectively)	3,793	4,037
Unrealized gain on available for sale securities (net of tax of $0 and $(7), respectively)		12
Total comprehensive income	20,581	15,939
Comprehensive loss attributable to non-controlling interest		(53)
Comprehensive income attributable to Black Hills Corporation	$ 20,581	$ 15,886

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	Six Months Ended June 30,	
	2009	2008
Net income	$ 50,972	$ 39,118

Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $2,928 and $20,462, respectively)	(4,795)	(37,792)
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $(4,060) and $(2,413), respectively)	7,163	4,310
Unrealized loss on available for sale securities (net of tax of $58)		(108)
Total comprehensive income	53,340	5,528
Comprehensive loss attributable to non-controlling interest		(130)
Comprehensive income attributable to Black Hills Corporation	$ 53,340	$ 5,398

Other comprehensive income from fair value adjustments on derivatives designated as cash flow hedges in the six months ended June 30, 2008 is primarily attributable to fluctuating oil and gas prices affecting the fair value of natural gas and crude oil swaps held in the Oil and Gas segment in 2008, and a decrease in interest rates affecting the fair value of interest rate swaps on variable rate debt.

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

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Amount from Equity-method Investees	Unrealized Loss on Available-for-Sale Securities	Total
As of June 30, 2009	$ (2,191)	$ (14,127)	$ (97)	$	$ (16,415)
As of December 31, 2008	$ (4,522)	$ (14,127)	$ (134)	$	$ (18,783)
As of June 30, 2008	$ (51,709)	$ (6,115)	$ (166)	$ (108)	$ (58,098)

(9) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock, as reported in Note 10 of the Notes to Consolidated Financial Statements in our 2008 Annual Report on Form 10-K.

Equity Compensation Plans

We granted 78,136 target performance shares to certain officers and business unit leaders for the January 1, 2009 through December 31, 2011 performance period. Actual shares are not issued until the end of the Performance Plan period (December 31, 2011). Performance shares are awarded based on our total stockholder return over the designated performance period as measured against a selected peer group and can range from 0 to 175% of target. In addition, our stock price must also increase during the performance period. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria. The performance awards are paid 50% in the form of cash and 50% in shares of common stock. The grant date fair value was $29.20 per share.

We issued 47,331 shares of common stock under the 2008 short-term incentive compensation plan during the six months ended June 30, 2009. Pre-tax compensation cost related to the award was approximately $1.6 million, which was accrued for in 2008.

We granted 81,877 restricted common shares during the six months ended June 30, 2009. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $2.2 million will be recognized over the three-year vesting period.

Total compensation expense recognized for all equity compensation plans for the three months ended June 30, 2009 and 2008 was $1.4 million and $0.5 million, respectively, and for the six months ended June 30, 2009 and 2008 was $1.8 million and $0.7 million, respectively.

As of June 30, 2009, total unrecognized compensation expense related to non-vested stock awards was $6.8 million and is expected to be recognized over a weighted-average period of 2.2 years.

Dividend Reinvestment and Stock Purchase Plan

We have a Dividend Reinvestment and Stock Purchase Plan under which stockholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We issued 80,746 new shares at a weighted-average price of $19.23 during the six months ended June 30, 2009. At June 30, 2009, 358,569 shares of unissued common stock were available for future offering under the Plan.

(10) EMPLOYEE BENEFIT PLANS

We have three non-contributory defined benefit pension plans (Plans) and three Postretirement Healthcare Plans (Healthcare Plans). One Plan covers employees of the following subsidiaries who meet certain eligibility requirements: Black Hills Service Company, Black Hills Power, WRDC and BHEP. The second Plan covers employees of our subsidiary, Cheyenne Light, who meet certain eligibility requirements. The third Plan covers employees of the Black Hills Energy utilities who meet certain eligibility requirements.

Defined Benefit Pension Plans

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Service cost	$ 1,929	$ 754	$ 3,858	$ 1,508
Interest cost	3,679	1,230	7,358	2,460
Expected return on plan assets	(3,458)	(1,573)	(6,916)	(3,146)
Prior service cost	41	41	82	82
Net loss	752		1,504	
Net periodic benefit cost	$ 2,943	$ 452	$ 5,886	$ 904

We made a $1.4 million contribution to the Cheyenne Light Pension Plan and a $2.5 million contribution to the Black Hills Energy Pension Plan in the second quarter of 2009; no contributions were made to the Black Hills Corporation Pension Plan during the second quarter of 2009. Additional contributions anticipated to be made to the Plans for 2009 and 2010 are expected to total approximately $9.5 million and $16.7 million, respectively.

Non-pension Defined Benefit Postretirement Healthcare Plans

Employees who are participants in our Healthcare Plans and who meet certain eligibility requirements are entitled to postretirement healthcare benefits.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Service cost	$ 260	$ 125	$ 520	$ 250

Interest cost		542		217		1,084		434
Expected return on asset		(56)				(112)		
Prior service (benefit)		(22)				(44)		
Net transition obligation		15		15		30		30
Net gain		(8)		(20)		(16)		(40)
Net periodic benefit cost	$	731	$	337	$	1,462	$	674

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We anticipate that we will make contributions to the Healthcare Plans for the 2009 fiscal year of approximately $3.3 million. The contributions are expected to be made in the form of benefits payments.

It has been determined that our post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy. The decrease in net periodic postretirement benefit cost due to the subsidy was approximately $0.1 million and $0.2 million for the three and six month periods ended June 30, 2009 and 2008, respectively.

Supplemental Non-qualified Defined Benefit Plans

Additionally, 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 are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Service cost	$ 117	$ 112	$ 234	$ 224
Interest cost	344	311	688	622
Prior service cost	1	3	2	6
Net loss	147	142	294	284
Net periodic benefit cost	$ 609	$ 568	$ 1,218	$ 1,136

We anticipate that we will make contributions to the Supplemental Plans for the 2009 fiscal year of approximately $1.0 million. The contributions are expected to be made in the form of benefit payments.

(11) SUMMARY OF INFORMATION RELATING TO SEGMENTS OF OUR BUSINESS

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. As of June 30, 2009, substantially all of our operations and assets are located within the United States.

The Utilities Group includes two reportable segments: Electric Utilities and Gas Utilities. We manage our electric and gas utility businesses predominantly by state; however, because our electric utilities and our gas utilities have similar economic characteristics, we aggregate our electric (and combination) utility businesses in the Electric Utilities reporting segment and our gas utility businesses in the Gas Utilities reporting segment. Electric Utilities include the operating results of the regulated electric utility operations of Black Hills Power and Colorado Electric, and the regulated electric and natural gas utility operations of Cheyenne Light. The natural gas operations within our combination utility, Cheyenne Light, provide relatively stable gross margins and overall financial results. Periodic variances are therefore rarely expected to significantly impact the operating results discussions for the Electric Utilities segment. Presentation of prior periods has been adjusted to reflect the combination of Black Hills Power and Cheyenne Light within the Electric Utilities segment. Gas Utilities, acquired on July 14, 2008, consists of the operating results of the regulated natural gas utility operations of Colorado Gas, Iowa Gas, Kansas Gas, and Nebraska Gas.

We conduct our operations through the following six reportable segments:

Utilities Group

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

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

Non-regulated Energy Group

Oil and Gas, which produces, explores and operates 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 Idaho;

Coal Mining, which engages in the mining and sale of coal from our mine near Gillette, Wyoming; and

Energy Marketing, which markets natural gas, crude oil and related services primarily in the western and central regions of the United States and Canada.

Segment information follows the same accounting policies as described in Note 1 of the Notes to Consolidated Financial Statements in our 2008 Annual Report on Form 10-K. In accordance with the provisions of SFAS 71, intercompany fuel sales to the regulated utilities are not eliminated.

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

Three Month Period Ended June 30, 2009	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$ 118,606	$ 215	$ 4,541
Gas Utilities	93,338		442
Non-regulated Energy:			
Oil and Gas	17,829		129
Power Generation	7,215		758
Coal Mining	7,746	5,747	(499)
Energy Marketing	7,738		2,210
Corporate			16,780
Inter-segment eliminations		(1,085)	220
Total	$ 252,472	$ 4,877	$ 24,581

Three Month Period Ended June 30, 2008	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$ 93,567	$ 363	$ 9,553
Gas Utilities			
Non-regulated Energy:			
Oil and Gas	34,209		7,197
Power Generation	2,135	6,376	(472)
Coal Mining	7,987	4,660	496
Energy Marketing	5,150		365
Corporate			(3,897)
Inter-segment eliminations		(1,174)	(39)
Total	$ 143,048	$ 10,225	$ 13,203

Six Month Period Ended June 30, 2009	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$ 255,665	$ 430	$ 13,858
Gas Utilities	349,676		17,708
Non-regulated Energy:			
Oil and Gas	34,340		(25,591)[(a)]
Power Generation	14,834		17,911
Coal Mining	15,683	12,212	319
Energy Marketing	14,557		3,247
Corporate			22,316
Inter-segment eliminations		(2,105)	438
Total	$ 684,755	$ 10,537	$ 50,206

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(a) As a result of lower natural gas prices at March 31, 2009, we recorded a non-cash ceiling test impairment of oil and gas assets included in the Oil and Gas segment in the first quarter of 2009. The lower prices at March 31, 2009 resulted in a $43.3 million pre-tax decrease in the full cost accounting method s ceiling limit for capitalized oil and gas property costs. The write-down in the net carrying value of our natural gas and crude oil properties was recorded as Impairment of long-lived assets and was based on the March 31, 2009 NYMEX price of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas; and NYMEX price of $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil.

Six Month Period Ended June 30, 2008	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$ 192,868	$ 670	$ 19,720
Gas Utilities			
Non-regulated Energy:			
Oil and Gas	60,331		9,749
Power Generation	4,449	12,926	(1,368)
Coal Mining	15,876	10,018	2,124
Energy Marketing	11,269		664
Corporate			(5,830)
Inter-segment eliminations		(2,284)	(39)
Total	$ 284,793	$ 21,330	$ 25,020

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Depreciation, depletion and amortization				

Utilities:				
Electric Utilities	$ 10,967	$ 7,892	$ 21,925	$ 15,639
Gas Utilities	7,499		15,680	
Non-regulated Energy:				
Oil and Gas	6,197	8,446	15,138	16,360
Power Generation	945	1,216	1,851	2,394
Coal Mining	3,588	2,186	7,574	3,852
Energy Marketing	129	185	262	368
Corporate	61	863	282	1,561
Total	$ 29,386	$ 20,788	$ 62,712	$ 40,174

	June 30, 2009	December 31, 2008	June 30, 2008
Total assets			
Utilities:			
Electric Utilities	$ 1,558,525	$ 1,485,040	$ 908,112
Gas Utilities	628,152	733,377	
Non-regulated Energy:			
Oil and Gas	347,198	403,583	454,433
Power Generation	119,876	155,819	148,262
Coal Mining	75,647	75,872	66,012
Energy Marketing	299,374	339,543	435,612
Corporate	82,968	186,409	51,509
Discontinued operations		246	598,294
Total	$ 3,111,740	$ 3,379,889	$ 2,662,234

(12) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and unregulated energy sector 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 counterparty risk. We have developed policies, processes, systems, and controls to manage and mitigate these risks.

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:

Commodity price risk associated with our marketing businesses, our natural long position with crude oil and natural gas reserves and production, and fuel procurement for certain of our gas-fired generation assets;

Interest rate risk associated with variable rate credit facilities;

Interest rate risk associated with changes in forward interest rates used to determine the mark-to-market adjustment on our interest rate swaps; and

Foreign currency exchange risk associated with natural gas marketing transacted in Canadian dollars.

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, currency exchange rates and commodity prices, the volatility of these prices and rates, and the liquidity of the related interest rate and commodity markets.

We actively manage our exposure to certain market risks as described in Note 2 of the Notes to Consolidated Financial Statements in our 2008 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 in this Note and Note 13 and Note 14.

Trading Activities

Natural Gas and Crude Oil Marketing

We have a natural gas and crude oil marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in the western and mid-continent regions of the United States and Canada.

Contracts and other activities at our natural gas and crude oil marketing operations are accounted for under the provisions of EITF 02-3 and SFAS 133. As such, all of the contracts and other activities at our natural gas and crude oil marketing operations that meet the definition of a derivative under SFAS 133 are accounted for at fair value. The fair values are recorded as either Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. The net gains or losses are recorded as Operating revenues in the accompanying Condensed Consolidated Statements of Income. EITF 02-3 precludes mark-to-market accounting for energy trading contracts that are not derivatives pursuant to SFAS 133. As part of our natural gas and crude oil marketing operations, we often employ strategies that include derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in limited circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, SFAS 133 generally does not allow us to mark inventory, transportation or storage positions to market. The result is that while a significant majority of our natural gas and crude oil marketing positions are economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions result from these accounting requirements.

To effectively manage our portfolios, we enter into forward physical commodity contracts, financial derivative instruments including over-the-counter swaps and options and storage and transportation agreements. The business activities of our Energy Marketing segment are conducted within the parameters as defined and allowed in the BHCRPP and further delineated in the gas marketing Risk Management Policies and Procedures as approved by our Executive Risk Committee. Our contracts do not include credit risk-related contingent features.

We use a number of quantitative tools to measure, monitor and limit our exposure to market risk in our natural gas and oil marketing portfolio. We limit and monitor our market risk through established limits on the nominal size of positions based on type of trade, location and duration. Such limits include those on fixed price, basis, index, storage, transportation and foreign exchange positions.

Daily risk management activities include reviewing positions in relation to established position limits, assessing changes in daily mark-to-market and other non-statistical risk management techniques.

The contract or notional amounts and terms of our natural gas and crude oil marketing activities and derivative commodity instruments are as follows:

	Outstanding at June 30, 2009		Outstanding at December 31, 2008		Outstanding at June 30, 2008	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of MMBtus)						
Natural gas basis swaps purchased	289,140	28	187,368	34	209,344	40
Natural gas basis swaps sold	302,324	28	186,710	34	212,498	40
Natural gas fixed - for - float swaps purchased	90,974	21	85,412	24	50,707	24
Natural gas fixed - for - float swaps sold	100,088	18	90,171	24	65,093	24
Natural gas physical purchases	168,381	18	131,937	16	130,253	22
Natural gas physical sales	184,873	21	145,706	21	168,938	22
Natural gas options purchased			1,440	3	7,650	9
Natural gas options sold			1,440	3	7,650	9

	Outstanding at June 30, 2009		Outstanding at December 31, 2008		Outstanding at June 30, 2008	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of Bbls)						
Crude oil physical purchases	5,595	6	7,446	12	6,713	18
Crude oil physical sales	4,925	6	6,251	12	5,084	18
Crude oil swaps/options purchased	42	3	435	24	515	6
Crude oil swaps/options sold	111	3	502	24	565	6

Derivatives and certain natural gas and crude oil marketing activities were marked to fair value on June 30, 2009, December 31, 2008 and June 30, 2008, and the related gains and/or losses recognized in earnings. The amounts included in the accompanying Condensed Consolidated Balance Sheets and Statements of Income are as follows (in thousands):

	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Cash Collateral Included in Derivative Assets/ Liabilities[(a)]	Unrealized (Loss)/Gain
June 30, 2009	$ 52,870	$ 1,802	$ 14,970	$ (1,917)	$ (9,267)	$ 32,352
December 31, 2008	$ 52,723	$ (145)	$ 15,553	$ (777)	$ 16,315	$ 54,117
June 30, 2008	$ 69,723	$ 14,010	$ 33,809	$ 2,480	$ (49,050)	$ (1,606)

(a) FIN 39 permits netting of receivables and payables when a legally enforceable master netting agreement exists between us and a counterparty. FIN 39-1 permits offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract. At June 30, 2009 and June 30, 2008, we had the right to reclaim cash collateral of $9.3 million and $49.1 million, respectively. At December 31, 2008, we had an obligation to return cash collateral of $16.3 million.

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in a fair value hedge transaction. These volumes include market adjustments based on published industry quotations. Market adjustments are recorded in Materials, supplies and fuel on the accompanying Condensed Consolidated Balance Sheets and the related unrealized gain/loss on the Condensed Consolidated Statements of Income, effectively offsetting the earnings impact of the unrealized gain/loss recognized on the associated derivative asset or liability described above. As of June 30, 2009, December 31, 2008 and June 30, 2008, the market adjustments recorded in inventory were $(3.8) million, $(9.4) million and $6.3 million, respectively.

Activities Other Than Trading

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, introduce commodity price risk and variability in our cash flows. We employ risk management methods to mitigate this commodity price risk and preserve our cash flows and we have adopted guidelines covering hedging for our natural gas and crude oil production. These guidelines have been approved by our Executive Risk Committee, and are routinely reviewed by our Board of Directors.

Over-the-counter swaps and options are used to mitigate commodity price risk and preserve cash flows. These derivative instruments fall under the purview of SFAS 133 and we elect to utilize hedge accounting as allowed under this Statement.

At June 30, 2009, December 31, 2008 and June 30, 2008, we had a portfolio of swaps and options to hedge portions of our crude oil and natural gas production. These transactions were designated at inception as cash flow hedges, properly documented and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

The derivatives were 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 was reported in other comprehensive income and the ineffective portion was reported in earnings.

On June 30, 2009, December 31, 2008 and June 30, 2008, we had the following derivatives and related balances (in thousands):

	Notional*	Maximum Terms in Years**	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax AOCI included in Balance Sheet	Earnings
June 30, 2009								
Crude oil swaps/options	480,000	0.25	$ 3,600	$ 1,453	$	$ 1,995	$ 2,543	$ 515
Natural gas swaps	9,862,050	0.75	14,012	1,612	361	1,392	13,871	
			$ 17,612	$ 3,065	$ 361	$ 3,387	$ 16,414	$ 515
December 31, 2008								
Crude oil swaps/options	435,000	0.25	$ 7,674	$ 3,464	$	$ 10	$ 9,642	$ 1,486
Natural gas swaps	8,523,500	1.00	11,828	3,749		297	15,280	
			$ 19,502	$ 7,213	$	$ 307	$ 24,922	$ 1,486
June 30, 2008								
Crude oil swaps/options	465,000	0.50	$ 389	$	$ 8,931	$ 5,996	$ (14,927)	$ 389

Natural gas swaps	10,474,000	1.34	702	26	25,363	11,040	(35,675)	
			$ 1,091	$ 26	$ 34,294	$ 17,036	$ (50,602)	$ 389

* Crude in Bbls, gas in MMBtu.

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

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Based on June 30, 2009 market prices, a $14.7 million gain would be realized and reported in pre-tax earnings during the next twelve months related to hedges of production. Estimated and actual realized gains will likely change during the next twelve months as market prices change.

Regulated Gas Utilities

Gas Hedges

Our Gas Utilities segment purchases and distributes natural gas in four states. During the winter heating season, our gas 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 exchange traded natural gas futures, options and basis swaps to reduce our customers underlying exposure to these fluctuations. These transactions are considered derivative transactions under SFAS 133, are marked-to-market, are not designated as hedges under SFAS 133 and, are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. Gains and losses, as well as option premiums, on these transactions are recorded as Regulatory assets or Regulatory liabilities in accordance with SFAS 71. Accordingly, the earnings impact is recognized in the Consolidated Income Statements as a component of PGA costs when the related costs are recovered through our rates as part of PGA costs in operating revenue.

The contract or notional amounts and terms of our natural gas derivative commodity instruments are as follows:

	Outstanding at June 30, 2009		Outstanding at December 31, 2008	
	Notional Amounts*	Latest Expiration (months)	Notional Amounts*	Latest Expiration (months)
Natural gas futures purchased	8,920,000	21	1,290,000	3
Natural gas options purchased	2,650,000	9	3,990,000	3
Natural gas options sold			820,000	3
Natural gas basis swaps purchased	377,500	9		

*gas in MMBtus

On June 30, 2009 and December 31, 2008, we had the following derivatives and related balances (in thousands):

	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Net Unrealized Loss Included in Regulatory Assets	Cash Collateral[(a)] Included in Derivative Assets/ Liabilities
June 30, 2009	$ 5,118 [(b)]	$ 162	$	$ 159	$ 2,163	$ 5,792
December 31, 2008	$ 4,224	$	$ 2,924	$	$ 11,668	$ 8,744

(a) FIN 39 permits the netting of receivables and payables when a legally enforceable master netting agreement exists between us and a counterparty. FSP FIN 39-1 permits offsetting of fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. At June 30, 2009 and December 31, 2008, we had the right to reclaim cash collateral of $5.8 million and $8.7 million, respectively.

(b) Includes option premium of $1.5 million which will be recorded as a regulatory asset upon settlement of the options.

Weather Derivatives

As approved in the State of Iowa, Iowa Gas uses a weather derivative to mitigate the effect of fluctuations from normal weather, but not for trading or speculative purposes. EITF 99-2 requires that these weather derivatives are accounted for by recording an asset or liability for the difference between the actual and contracted threshold cooling or heating degree days in the period, multiplied by the contract price. Any gains and losses recorded on the contracts are recorded as regulatory assets or regulatory liabilities and do not have any impact on our financial position. These contracts terminated in the first quarter of 2009.

Financing Activities

We are exposed to interest rate risk associated with fluctuations in the interest rate on our variable interest rate debt. In order to manage this risk, we have entered into floating-to-fixed interest rate swap agreements that effectively convert the debt s variable interest rate to a fixed rate.

On June 30, 2009, December 31, 2008 and June 30, 2008, our interest rate swaps and related balances were as follows (in thousands):

	Current Notional Amount	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax AOCI included in Balance Sheet	Pre-tax Gain/(Loss) included in Income Statement
June 30, 2009									
Interest rate swaps	$ 150,000	5.04%	7.50	$	$	$ 6,045	$ 10,469	$ (16,514)	$
Interest rate swaps*	250,000	5.67%	0.50			47,971			46,469
	$ 400,000			$	$	$ 54,016	$ 10,469	$ (16,514)	$ 46,469
December 31, 2008									
Interest rate swaps	$ 150,000	5.04%	8.00	$	$	$ 5,740	$ 22,495	$ (28,235)	$
Interest rate swaps*	250,000	5.67%	1.00			94,440			(94,440)
	$ 400,000			$	$	$ 100,180	$ 22,495	$ (28,235)	$ (94,440)
June 30, 2008									
Interest rate swaps	$ 150,000	5.04%	8.25	$	$	$ 2,760	$ 3,641	$ (6,401)	$
Interest rate swaps	250,000	5.67%	0.50			18,926		(18,926)	
	$ 400,000			$	$	$ 21,686	$ 3,641	$ (25,327)	$

* The $250 million notional amount interest rate swaps represent the interest rate swaps that we de-designated in the fourth quarter of 2008 as disclosed in Note 2 of the Notes to Consolidated Financial Statements in our 2008 Annual Report on Form 10-K.

Based on June 30, 2009 market interest rates and balances, a loss of approximately $6.0 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change. Furthermore, refer to Note 13 for further information related to the $250 million notional swaps that are not designated as hedges for accounting purposes.

Foreign Exchange Contracts

Our Energy Marketing Segment conducts its gas marketing in the United States and Canada. Transactions in Canada are generally transacted in Canadian dollars and create exchange risk for us. To mitigate this risk, we enter into forward currency exchange contracts to offset earnings volatility from changes in exchange rates between the Canadian and United States dollar.

The outstanding forward exchange contracts, which had a fair value of $(0.3) million, $(0.2) million and $0.3 million at June 30, 2009, December 31, 2008 and June 30, 2008, respectively, have been recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. For the three and six months ended June 30, 2009, the unrealized foreign exchange gain (loss) was $(0.3) million and less than $0.1 million, respectively, while for the three and six months ended June 30, 2008, the amount of unrealized foreign exchange gain was $0.6 million and $0.9 million, respectively. For the three and six months ended June 30, 2009, the realized foreign currency gain was $1.4 million and $0.7 million, respectively, while for the three and six months ended June 30, 2008, the amount of foreign currency (loss) gain was $(0.2) million and $0.1 million, respectively. Currency transaction gains or losses on transactions executed in Canadian dollars are recorded in Operating revenues on the accompanying Condensed Consolidated Statements of Income as incurred.

All forward exchange contracts outstanding at June 30, 2009 will settle by July 24, 2009 and were as follows:

	Outstanding at June 30, 2009		Outstanding at December 31, 2008		Outstanding at June 30, 2008	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(Dollars, in thousands)						
Canadian dollars purchased	$ 19,000	1	$ 52,000	1	$ 47,000	1
Canadian dollars sold	$		$		$ 6,000	1

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(13) QUANTITATIVE DISCLOSURES RELATED TO DERIVATIVES

As required by SFAS 161, 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 FIN 39 and under terms of our master netting agreements. Further, the amounts do not include net cash collateral of $15.1 million on deposit in margin accounts at June 30, 2009 to collateralize certain financial instruments, which is included in Derivative assets current. 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 agree to the fair value measurements presented in Note 12 and Note 14. The following table presents the fair value and balance sheet classification of our derivative instruments as of June 30, 2009 (in thousands):

Fair Value as of June 30, 2009

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges under SFAS 133:			
Commodity derivatives	Derivative assets current	$ 7,500	$ 3,444
Commodity derivatives	Derivative assets non-current	3	
Commodity derivatives	Derivative liabilities current	55	363
Commodity derivatives	Derivative liabilities non-current		5
Interest rate swaps	Derivative liabilities current		6,045
Interest rate swaps	Derivative liabilities non-current		10,469
Total derivatives designated as hedges under SFAS 133		$ 7,558	$ 20,326
Derivatives not designated as hedges under SFAS 133:			
Commodity derivatives	Derivative assets current	$ 243,199	$ 186,714
Commodity derivatives	Derivative assets non-current	15,875	10,849
Commodity derivatives	Derivative liabilities current	12,776	27,465
Commodity derivatives	Derivative liabilities non-current	79	1,703
Interest rate swap	Derivative liabilities current		47,971
Foreign currency derivatives	Derivative liabilities current		334
Total derivatives not designated as hedges under SFAS 133		$ 271,929	$ 275,036

A description of our derivative activities is discussed in Note 12. The following tables present the impact that derivatives had on our Condensed Consolidated Statements of Income for the three and six months ended June 30, 2009.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged items on our accompanying Condensed Consolidated Statements of Income for the three and six months ended June 30, 2009 is presented as follows:

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income for the Three and Six Months Ended June 30, 2009

Fair Value Hedges
(in thousands)

Derivatives in SFAS 133 Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended June 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income	Six Months Ended June 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$ (639)	$ 6,881
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	1,415	(5,540)
		$ 776	$ 1,341

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Cash Flow Hedges

The impact of cash flow hedges on our Condensed Consolidated Statements of Income for the three and six months ended June 30, 2009 is presented as follows:

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income and the Balance Sheet for the Three Months Ended June 30, 2009

Cash Flow Hedges
(in thousands)

Derivatives in SFAS 133 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 Gain/(Loss) Reclassified 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	$ 9,606	Interest expense	$ (610)		$
Commodity derivatives	(15,663)	Operating revenue	6,546	Operating revenue	(167)
Total	$ (6,057)		$ 5,936		$ (167)

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income and the Balance Sheet for the Six Months Ended June 30, 2009

Cash Flow Hedges
(in thousands)

Derivatives in SFAS 133 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 Gain/(Loss) Reclassified 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	$ 11,721	Interest expense	$ (1,958)		$
Commodity derivatives	(8,508)	Operating revenue	13,181	Operating revenue	(1,094)
Total	$ 3,213		$ 11,223		$ (1,094)

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments that have not been designated as hedges on our Condensed Consolidated Statements of Income for the three and six months ended June 30, 2009 is presented below.

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income for the Three and Six Months Ended June 30, 2009

Derivatives Not Designated as Hedging Instruments
(in thousands)

Derivatives Not Designated as Hedging Instruments under SFAS 133	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended June 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income	Six Months Ended June 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$ (9,239)	$ (17,364)
Interest rate swap	Interest rate swap	31,706	46,469
Foreign currency contracts	Operating revenue	(350)	(107)
		$ 22,117	$ 28,998

(14) DERIVATIVE FINANCIAL INSTRUMENTS AND FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

We adopted SFAS 157 effective January 1, 2008 for all financial assets and liabilities and any other assets and liabilities that are recognized at fair value on a recurring basis. SFAS 157 establishes a new framework for measuring fair value and expands related disclosures. Broadly, SFAS 157 provides a single definition of fair value 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. SFAS 157 establishes a three-tier valuation hierarchy based upon observable and non-observable inputs.

Financial assets and liabilities carried at fair value are classified and disclosed in one of the following three categories:

Level 1 Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities and listed derivatives.

Level 2 Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 - Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management s best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

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 as of June 30, 2009, December 31, 2008 and June 30, 2008. As required by SFAS 157, 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 their placement within the fair value hierarchy levels.

Recurring Fair Value Measures (in thousands)	At Fair Value as of June 30, 2009				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[(a)]	Total
Assets:					
Commodity derivatives	$	$ 252,368	$ 13,189	$ (184,929)	$ 80,628
Liabilities:					
Commodity derivatives	$	$ 208,577	$ 8,036	$ (199,987)	$ 16,626
Foreign currency derivatives		334			334
Interest rate swaps		64,486			64,486
Total	$	$ 273,397	$ 8,036	$ (199,987)	$ 81,446

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Recurring Fair Value Measures (in thousands)	At Fair Value as of December 31, 2008				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[(a)]	Total
Assets:					
Commodity derivatives	$	$ 267,932	$ 28,407	$ (208,952)	$ 87,387
Liabilities:					
Commodity derivatives	$	$ 211,672	$ 12,009	$ (201,381)	$ 22,300
Foreign currency derivatives		227			227
Interest rate swaps		122,675			122,675
Total	$	$ 334,574	$ 12,009	$ (201,381)	$ 145,202

Recurring Fair Value Measures (in thousands)	At Fair Value as of June 30, 2008				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[(a)]	Total
Assets:					
Short - term investments	$	$	$ 7,309	$	$ 7,309
Commodity derivatives		291,848	24,424	(231,461)	84,811
Total	$	$ 291,848	$ 31,733	$ (231,461)	$ 92,120
Liabilities:					
Commodity derivatives	$	$ 355,358	$ 13,092	$ (280,511)	$ 87,939
Interest rate swaps		25,327			25,327
Foreign currency derivatives		318			318
Total	$	$ 381,003	$ 13,092	$ (280,511)	$ 113,584

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(a) FIN 39 permits the netting of receivables and payables when a legally enforceable master netting agreement exists between us and a counterparty. FIN 39-1 permits offsetting of fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. Cash collateral included on deposit in margin accounts at June 30, 2009, December 31, 2008 and June 30, 2008 totaled a net $15.1 million, $(7.6) million and $49.1 million, respectively. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

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The following tables present the changes in level 3 recurring fair value for the three and six months ended June 30, 2009 and 2008, respectively (in thousands):

	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
	Commodity Derivatives	Commodity Derivatives
Balance as of beginning of period	$ 13,407	$ 16,398
Realized and unrealized losses	(1,310)	(1,555)
Purchases, issuance and settlements	(747)	(6,054)
Transfers in and/or out of level 3[(a)]	(6,197)	(3,636)
Balances as of June 30, 2009	$ 5,153	$ 5,153
Changes in unrealized losses relating to instruments still held as of June 30, 2009	$ (7,013)	$ (10,455)

(a) Transfers into level 3 represent existing assets and liabilities that were either previously categorized as a higher level for which the inputs became unobservable. Transfers out of level 3 represent existing assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

	Three Months Ended June 30, 2008		
	Commodity Derivatives	Short-term Investments	Total
Balance as of April 1, 2008	$ 6,973	$ 7,290	$ 14,263
Realized and unrealized gains	5,793	19	5,812
Purchases, issuance and settlements	(1,434)		(1,434)
Balances as of June 30, 2008	$ 11,332	$ 7,309	$ 18,641
Changes in unrealized gains relating to instruments still held as of June 30, 2008	$ 727	$ 19	$ 39

	Six Months Ended June 30, 2008		
	Commodity Derivatives	Short-term Investments	Total
Balance as of January 1, 2008	$ 6,422	$	$ 6,422
Realized and unrealized gains (losses)	6,830	(166)	6,664
Purchases, issuance and settlements	(1,920)	7,475	5,555
Balances as of June 30, 2008	$ 11,332	$ 7,309	$ 18,641
Changes in unrealized losses relating to instruments still held as of June 30, 2008	$ (62)	$ (166)	$ (228)

Gains and losses (realized and unrealized) for level 3 commodity derivatives are included in Operating revenues on the accompanying Condensed Consolidated Statements of Income. We believe an analysis of commodity derivatives classified as level 3 needs to be undertaken with the understanding that these items may be economically hedged as part of a total portfolio of instruments that may be classified in level 1 or 2, or with instruments that may not be accounted for at fair value. Accordingly, gains and losses associated with level 3 balances may not necessarily reflect trends occurring in the underlying business. Further, unrealized gains and losses for the period from level 3 items may be offset by unrealized gains and losses in positions classified in level 1 or 2, as well as positions that have been realized during the quarter. Short-term investments included in level 3 represent auction rate securities held at June 30, 2008. The unrealized losses for these investments are recognized in Accumulated other comprehensive income on the accompanying Condensed Consolidated Balance Sheets.

Fair Value of Financial Instruments

The estimated fair value of our financial instruments at June 30, 2009 is as follows (in thousands):

	Carrying Amount	Fair Value
Cash and cash equivalents	$ 122,351	$ 122,351
Derivative financial instruments assets	$ 80,629	$ 80,629
Derivative financial instruments liabilities	$ 81,445	$ 81,445
Notes payable	$ 270,500	$ 270,500
Long-term debt, including current maturities	$ 751,329	$ 776,616

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

Cash and Cash Equivalents and Restricted Cash

The carrying amount approximates fair value due to the short maturity of these instruments.

Derivative Financial Instruments

These instruments are carried at fair value. Descriptions of the various instruments we use and the valuation method employed are included in Notes 12 and 14.

Notes Payable

The carrying amount approximates fair value due to their variable interest rates with short reset periods.

Long-Term Debt

The fair value of our long-term debt is estimated based on quoted market rates for debt instruments having similar maturities and similar debt ratings.

(15) COMMITMENTS AND CONTINGENCIES

Legal Proceedings

We are subject to various legal proceedings, claims and litigation as described in Note 18 of the Notes to Consolidated Financial Statements in our 2008 Annual Report on Form 10-K. There have been no material developments in any previously reported proceedings or any new material proceedings that have developed or material proceedings that have terminated during the first six months of 2009.

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our consolidated financial statements are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our consolidated financial statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of June 30, 2009, cannot be reasonably determined and could have a material adverse effect on our results of operations or financial position.

FERC Compliance Investigation

During 2007, following an internal review of natural gas marketing activities conducted within the Energy Marketing segment, we identified possible instances of noncompliance with regulatory requirements applicable to those activities. We notified the enforcement staff of FERC of our findings and shared information with a purpose to resolve any potential enforcement concerns. We also evaluated public announcements of civil penalties that have been levied against other companies for violations of FERC regulatory requirements. We believe we have adequately reserved for the estimated potential penalty that could be levied on us. Although the outcome of any legal or regulatory proceedings resulting from these matters cannot be predicted with any certainty, and while the final resolution of these matters could have a material impact on the consolidated net income of any particular period, the outcome of this proceeding is not expected to have a material impact upon our overall consolidated financial position.

Partial Sale of Wygen I to MEAN

During August 2008, we entered into a definitive agreement to sell a 23.5% ownership interest in the Wygen I plant to MEAN. The sale was completed in January 2009 for a price of $51.0 million, which was based on the then-current replacement cost for the coal-fired plant. We realized an after-tax gain of $16.9 million on the sale, and our property, plant and equipment was reduced by $26.2 million. We retain responsibility for operations of the plant, and at closing entered into a site lease, and agreements with MEAN for coal supply and operations. In addition, we terminated a 10-year power purchase contract requiring MEAN to purchase 20 MW of power annually from Wygen I.

Sale to MDU

On April 9, 2009, Black Hills Power sold to MDU a 25% ownership interest in its Wygen III generation facility currently under construction. At closing, MDU made a payment to us for its 25% share of the costs to date on the ongoing construction of the facility. Proceeds of $32.8 million were received of which $30.2 million was used to pay down a portion of the Acquisition Facility. MDU will continue to reimburse Black Hills Power for its 25% of the total costs paid to complete the project. In conjunction with the sales transaction, we also modified a 2004 power purchase agreement between Black Hills Power and MDU under which Black Hills Power supplied MDU with 74 MW of capacity and energy through 2016.

Long-Term Power Sales Agreement

In March 2009, our 10-year power sales contract between MEAN and Black Hills Power that originally would have expired in 2013 was re-negotiated and extended until 2023. Under the new contract, MEAN will purchase 20 MW of unit-contingent capacity from the Neil Simpson II and Wygen III plants, with capacity purchase decreasing to 15 MW in 2018, 12 MW in 2020 and 10 MW in 2022. The unit-contingent capacity amounts from Wygen III and Neil Simpson II plants are as follows:

2009-2017	20 MW	10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
2018-2019	15 MW	10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
2020-2021	12 MW	6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
2022-2023	10 MW	5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II

Purchase Power Agreement

In April 2009, Cheyenne Light entered into an agreement to purchase 30 MW of renewable energy from Duke Energy s Silver Sage wind site through a 20-year purchase power agreement. Construction is expected to be completed by the end of 2009.

(16) ACQUISITION

Aquila Transaction

On July 14, 2008, we completed the acquisition of a regulated electric utility in Colorado and four regulated gas utilities in Colorado, Kansas, Nebraska and Iowa. See Note 21 of the Notes to our 2008 Annual Report on Form 10-K for additional information.

This acquisition has been accounted for under the purchase method of accounting, and accordingly, the purchase price has been allocated to the acquired assets and liabilities based on preliminary estimates of the fair values of the assets purchased and liabilities assumed as of the date of acquisition. Adjustments to the purchase price allocation during the six months ended June 30, 2009 included working capital adjustments of $0.2 million. Outstanding adjustments relate to property taxes and inventory, which we finalized subsequent to June 30, 2009. The estimated purchase price allocations are subject to adjustment, generally within one year of the date of acquisition. Adjustments to goodwill subsequent to June 30, 2009 totaled approximately $0.1 million. Allocation of the purchase price as of June 30, 2009 is as follows (in thousands):

Current assets	$	113,261
Property, plant and equipment		542,094
Derivative assets		4,695
Goodwill		344,457
Intangible assets		4,884
Deferred assets		70,939
	$	1,080,330
Current liabilities	$	95,257
Deferred credits and other liabilities		54,550
	$	149,807
Net assets	$	930,523

After finalization of the working capital adjustment, the allocation of the purchase price resulted in $344.5 million of goodwill and $4.9 million of intangible assets. Goodwill of $246.5 million was allocated to the Electric Utility and $98.0 million was allocated to the Gas Utilities.

The results of operations of the acquired regulated utilities have been included in the accompanying Condensed Consolidated Financial Statements since the acquisition date.

The following pro-forma consolidated results of operations have been prepared as if the acquisition of the regulated utilities had occurred on January 1, 2008 (in thousands, except per share amounts):

	Three Month Period Ended June 30, 2008	Six Month Period Ended June 30, 2008
Operating revenues	$ 338,173	$ 826,823
Income from continuing operations	17,603	49,049
Net income available for common stock	26,596	63,017
Earnings per share		
Basic:		
Continuing operations	$ 0.46	$ 1.29
Total	$ 0.69	$ 1.66
Diluted:		
Continuing operations	$ 0.46	$ 1.28
Total	$ 0.69	$ 1.64

The above pro-forma information is presented for informational purposes only and is not necessarily indicative of the results of operations that would have been achieved had the acquisition been consummated at that time; nor is it intended to be a projection of future results.

(17) INCOME TAXES

Our effective tax rate for the six months ended June 30, 2009 was lower than previous periods as a result of a positive adjustment in the first quarter of 2009 for a previously recorded tax position. We recorded a $3.8 million reduction in tax expense in our Oil and Gas segment due to a re-measurement of this position which was recorded in accordance with FIN 48.

(18) DISCONTINUED OPERATIONS

We account for our discontinued operations under the provisions of SFAS 144. Accordingly, results of operations and the related charges for discontinued operations have been classified as Income from discontinued operations, net of taxes in the accompanying Condensed Consolidated Statements of Income. Assets and liabilities of the discontinued operations have been reclassified and reflected on the accompanying Condensed Consolidated Balance Sheets as Assets of discontinued operations and Liabilities of discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the reclassifications on a consistent basis.

Sale of IPP Assets

On April 29, 2008, we entered into a definitive agreement to sell seven of our IPP plants to affiliates of Hastings and IIF for $840 million, subject to certain working capital adjustments. The transaction was completed July 11, 2008. Under the agreement, we received net pre-tax cash proceeds of $756 million, including the effects of estimated working capital adjustments and other costs and the required payoff of approximately $67.5 million of associated project level debt. The after-tax gain recorded on the asset sale, after finalization of the working capital adjustments, was $140.5 million, of which $139.7 million was recorded in 2008 in discontinued operations.

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Revenues and net income from the discontinued operations associated with the divested IPP plants were as follows (in thousands):

	Three Months Ended June 30, 2009	2008*	Six Months Ended June 30, 2009	2008*
Operating revenues	$	$ 27,705	$	$ 54,065
Pre-tax income from discontinued operations		13,949	1,190	21,853
Income tax expense		4,884	424	7,954
Net income from discontinued operations	$	$ 9,065	$ 766	$ 13,899

* In accordance with GAAP, during the second quarter of 2008, the Company ceased recording depreciation and amortization expense on the IPP facilities.

Allocation of corporate expenses to discontinued operations was made in accordance with SFAS 144 and EITF 87-24. The indirect corporate costs and inter-segment interest expense related to the IPP assets sold and not reclassified to discontinued operations were $4.2 million and $7.7 million after-tax for the three and six months ended June 30, 2008, respectively. These allocated costs remain in the Power Generation segment.

Interest expenses included within the operations of the discontinued entities were recorded pursuant to EITF 87-24 and include interest expense on debt which was required to be repaid as a result of the sale transaction. In accordance with EITF 87-24, interest expense was allocated to discontinued operations based on the ratio of the assets sold to total Company net assets, excluding the known debt repayment. For the three and six months ended June 30, 2008, respectively, interest expense allocated to discontinued operations was $2.0 million and $4.7 million.

Net assets associated with the divested IPP plants were as follows (in thousands):

	June 30, 2008
Current assets	$ 29,437
Property, plant and equipment, net of accumulated depreciation	506,609
Goodwill	26,500
Intangible assets (net of accumulated amortization of $28,958)	20,204
Other non-current assets	15,146
Current liabilities	(9,148)
Long-tem debt	(67,500)
Other non-current liabilities	(86)
Net assets	$ 521,162

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

We are a diversified 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 reportable operating segments:

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

Our Utilities Group consists of our electric and gas utility segments. Our Electric Utilities generate, transmit and distribute electricity to approximately 202,100 customers in South Dakota, Wyoming, Colorado and Montana. In addition, Cheyenne Light, which is also reported within the Electric Utilities segment, provides natural gas to approximately 33,300 customers in Wyoming. Our Gas Utilities segment serves approximately 524,000 natural gas customers in Colorado, Nebraska, Iowa and Kansas. Our Non-regulated Energy Group engages in the production of coal, natural gas and crude oil primarily in the Rocky Mountain region; the production of electric power through ownership of a portfolio of generating plants and the sale of electric power and capacity primarily under long-term contracts; and the marketing of natural gas, crude oil and related services.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 82.

Significant Events

Wygen III Power Plant Project and Sale to MDU

In March 2008, we received final regulatory approval for construction of Wygen III. Construction began immediately and the 110 MW coal-fired base load electric generating facility is expected to be completed by June, 2010. The expected cost of construction is approximately $255 million, which includes estimates for AFUDC. A 2004 Purchase Power Agreement between Black Hills Power and MDU included an option to purchase an ownership interest in Wygen III. MDU exercised this option, and under an agreement entered into in April 2009, we will retain an undivided ownership of 75% of the facility with MDU owning the remaining 25%. At closing, MDU reimbursed us for its 25% of the total costs incurred to date on the ongoing construction of the facility. We received proceeds of $32.8 million, of which $30.2 million was used to pay down a portion of the Acquisition Facility. We will retain responsibility for operations of the facility with a life-of-plant site lease and agreements with MDU for operations and coal supply. In conjunction with the sales transaction, we also modified a 2004 power purchase agreement between Black Hills Power and MDU under which Black Hills Power supplied MDU with 74 MW of capacity and energy through 2016.

Partial Sale of Wygen I to MEAN

During August 2008, we entered into a definitive agreement to sell a 23.5% ownership interest in the Wygen I plant to MEAN. The sale was completed in January, 2009 for a price of $51.0 million, which was based on the then current replacement cost for the coal-fired plant. We realized an after-tax gain of $16.9 million on the sale, and our property, plant and equipment was reduced by $26.2 million. We retain responsibility for operations of the plant, and at closing entered into a site lease, and agreements with MEAN for coal supply and operations. In addition, we terminated a 10-year power purchase contract requiring MEAN to purchase 20 MW of power annually from Wygen I.

Extension of Long-Term Power Sales Agreement with MEAN

In March 2009, our 10-year power sales contract between MEAN and Black Hills Power that originally expired in 2013 was re-negotiated and extended until 2023. Under the new contract, MEAN will purchase 20 MW of unit-contingent capacity from the Neil Simpson II and the Wygen III plants with capacity purchase decreasing to 15 MW in 2018, 12 MW in 2020 and 10 MW in 2022. The unit-contingent capacity amounts from Wygen III and Neil Simpson II plants are as follows:

2009-2017	20 MW	10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
2018-2019	15 MW	10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
2020-2021	12 MW	6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
2022-2023	10 MW	5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II

Colorado Electric Resource Plan

In August 2008, Black Hills Energy filed a long-term Electric Resource Plan with the CPUC proposing to build five natural gas-fired power generation facilities totaling 350 MW to support the customers of Colorado Electric. In the first quarter of 2009, Colorado Electric received approval from the CPUC to build two of the five power generation facilities representing approximately 150 MW. The power generation facilities are part of a plan to replace the purchased power agreement currently with PSCo which expires on December 31, 2011. The initial decision of the CPUC waives the competitive bidding process for the two turbines; the remaining capacity and energy needs of the utility will be acquired from other power producers through a competitive bid process, which is on-going. Our Power Generation segment was allowed to bid in the competitive bidding process. The Company is currently evaluating bids for the remaining capacity and energy requirements and anticipates executing power purchase agreements with the successful bidder(s) prior to year-end.

Silver Sage Wind Site

In April 2009, Cheyenne Light entered into an agreement to purchase 30 MW of renewable energy from Duke Energy s Silver Sage wind site through a 20-year purchase power agreement. Construction is expected to be completed by the end of 2009.

Purchase Power Agreement with MEAN

In July 2009, we entered into a five-year PPA with MEAN. The contract commences the month following the commercial operations of Wygen III. Under this contract, MEAN will purchase 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III.

Results of Operations

Executive Summary

Three Months Ended June 30, 2009 Compared to Three Months Ended June 30, 2008.

Income from continuing operations for the three month period ended June 30, 2009 was $24.6 million, or $0.64 per share, compared to $13.2 million, or $0.34 per share, reported for the same period in 2008. For the three month period ended June 30, 2009, net income available for common stock was $24.6 million or $0.64 per share, compared to $22.2 million, or $0.58 per share, for the same period in 2008.

Included in 2009 are the results from the utilities acquired from Aquila on July 14, 2008 and impact of a $20.6 million after-tax non-cash gain, resulting from an unrealized net mark-to-market gain for certain interest rate swaps entered into in 2007.

The Utilities Group includes the 2009 results of the electric and gas utilities acquired from Aquila on July 14, 2008. Earnings reflect the impact of lower margins from off-system sales due to lower energy prices, higher interest expense, and higher employee benefit costs.

Earnings from the Oil and Gas segment decreased for the quarter due to a decrease in operating revenues resulting from lower oil and gas prices and lower production, partially offset by lower production taxes due to lower oil and gas prices. Average oil prices received, net of hedges, decreased 42% and average gas prices received, net of hedges, decreased 45%.

Lower earnings from the Coal Mining segment resulted from lower coal sales volume, increased depreciation and coal taxes, partially offset by revenue increases from higher average sale prices and lower diesel fuel costs.

Increased earnings from the Energy Marketing segment reflect higher realized natural gas and crude oil margins received, partially offset by unrealized mark-to-market losses. Realized natural gas margins were primarily impacted by differing market conditions between years.

Earnings from the Power Generation segment were impacted by increased interest expense and lower margins due to the net earnings impact of replacing the 20 MW PPA with operating and site lease agreements related to MEAN s purchase of a 23.5% ownership interest in Wygen I, partially offset by operating fees charged to MEAN. For the three months ended June 30, 2008, results included $6.4 million pre-tax indirect corporate costs and intersegment net interest expense not reclassified to discontinued operations for the IPP Transaction.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008.

Income from continuing operations for the six month period ended June 30, 2009 was $50.2 million, or $1.30 per share, compared to $25.0 million, or $0.65 per share, reported for the same period in 2008. For the six month period ended June 30, 2009, net income available for common stock was $51.0 million or $1.32 per share, compared to $39.0 million, or $1.01 per share, for the same period in 2008.

Included in the 2009 results are the earnings from the utilities acquired from Aquila on July 14, 2008 and impacts from the following notable items:

$16.9 million after-tax gain from sale of a 23.5% interest in the Wygen I generation facility on January 22, 2009;

$30.2 million after-tax non-cash gain, resulting from an unrealized net mark-to-market gain for certain interest rate swaps entered into in 2007; and

Non-cash impairment charge of oil and gas assets totaling $27.8 million after-tax, driven by lower natural gas and crude oil prices at the end of the first quarter of 2009.

The Utilities Group includes the 2009 results of the electric and gas utilities acquired from Aquila on July 14, 2008. Earnings reflect the impact of increased retail margins from an approved rate case for transmission rates and the impact of AFUDC related to the Wygen III construction partially offset by lower margins from off-system sales due to lower energy prices and higher interest expense.

Earnings from the Oil and Gas segment decreased from 2008 due to a decrease in operating revenues reflecting lower oil and gas prices and lower production and a first quarter of 2009 impairment charge, partially offset by lower production taxes and LOE costs compared to 2008. Average oil prices received, net of hedges, decreased 40% and average gas prices received, net of hedges, decreased 40%.

Lower earnings from the Coal Mining segment in 2009 resulted from lower coal sales volumes, increased depreciation and coal taxes, partially offset by revenue increases from higher average sale prices and lower diesel fuel costs.

Increased earnings from the Energy Marketing segment in 2009 reflect higher realized natural gas and crude oil margins received, partially offset by unrealized mark-to-market losses. Realized natural gas margins were primarily impacted by differing market conditions between years.

Increased earnings from the Power Generation segment in 2009 were impacted by a $16.9 million after-tax gain on the sale of a 23.5% ownership interest in the Wygen I power generation facility to MEAN and increased interest expense, partially offset by lower margins due to the net earnings impact of replacing the 20 MW PPA with operating and site lease agreements related to MEAN s purchase of the 23.5% ownership interest in Wygen I. In addition, for the six months ended June 30, 2008, results included $11.8 million of pre-tax allocated indirect corporate costs and intersegment net interest expense not classified to discontinued operations for the IPP Transaction.

Income from discontinued operations was $0.8 million, or $0.02 per share, for the six month period ended June 30, 2009, compared to $14.1 million, or $0.36 per share, for the same period in 2008. The Income from discontinued operations in 2009 relates to working capital adjustments and the related impact on the gain on sale from the IPP Transaction.

Consolidated Results

The following business group and segment information does not include intercompany eliminations or results of discontinued operations. Amounts are presented on a pre-tax basis unless otherwise indicated.

Revenues and Income (loss) from continuing operations provided by each business group were as follows (in thousands):

	Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
Revenues				
Utilities	$ 211,944	$ 93,567	$ 605,341	$ 192,868
Non - regulated Energy	45,405	59,706	89,951	113,255
	$ 257,349	$ 153,273	$ 695,292	$ 306,123
Income (loss) from continuing operations				
Utilities	$ 4,983	$ 9,553	$ 31,566	$ 19,720
Non - regulated Energy	2,818	7,547	(3,676)	11,130
Corporate	16,780	(3,897)	22,316	(5,830)
	$ 24,581	$ 13,203	$ 50,206	$ 25,020

Income from continuing operations increased $11.4 million for the three months ended June 30, 2009 due primarily to the following:

- $0.4 million income from the Gas Utilities segment;
- A $1.2 million increase in Power Generation earnings;
- A $1.8 million increase in Energy Marketing earnings; and
- A $20.7 million increase in corporate income.

The increases in earnings were partially offset by:

- A $5.0 million decrease in Electric Utilities earnings;
- A $7.1 million decrease in Oil and Gas earnings; and
- A $1.0 million decrease in Coal Mining earnings.

Income from continuing operations increased $25.2 million for the six months ended June 30, 2009 due primarily to the following:

- $17.7 million income from the Gas Utilities segment;
- A $19.3 million increase in Power Generation earnings;
- A $2.6 million increase in Energy Marketing earnings; and
- A $28.1 million increase in corporate income.

The increases in earnings were partially offset by:

- A $5.9 million decrease in Electric Utilities earnings;
- A $35.3 million decrease in Oil and Gas earnings; and
- A $1.8 million decrease in Coal Mining earnings.

See the following discussion under the captions Utilities Group and Non-regulated Energy Group for more detail on our results of operations by business segment.

Utilities Group

We acquired from Aquila regulated electric utility assets in Colorado and four regulated gas utilities assets operating in Colorado, Nebraska, Iowa and Kansas. Operations from the acquired utilities have been included in the Utilities Group results from the July 14, 2008 acquisition date.

With the completion of the acquisition, we are reporting 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, Nebraska, Iowa and Kansas.

Electric Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Revenue electric	$ 112,998	$ 82,178	$ 235,174	$ 164,751
Revenue gas	5,823	11,752	20,922	28,787
Total revenue	118,821	93,930	256,096	193,538
Fuel and purchased power electric	58,938	37,945	123,836	78,199
Purchased gas	2,705	8,597	12,962	20,457
Total fuel and purchased power	61,643	46,542	136,798	98,656
Gross margin electric	54,060	44,233	111,338	86,552
Gross margin gas	3,118	3,155	7,960	8,330
Total gross margin	57,178	47,388	119,298	94,882
Operating expenses	43,338	29,466	86,212	57,093
Operating income	$ 13,840	$ 17,922	$ 33,086	$ 37,789
Income from continuing operations and net income available for common stock	$ 4,541	$ 9,553	$ 13,858	$ 19,720

The following tables summarize regulated sales revenues, quantities generated and purchased, sales quantities and degree days for our Electric Utilities segment. Included in 2009 reported amounts for the periods are the operations of Colorado Electric, acquired July 14, 2008 as part of the Aquila Transaction:

Sales Revenues	Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
	(in thousands)			
Residential:				
Black Hills Power	$ 10,391	$ 10,002	$ 24,672	$ 22,980
Cheyenne Light	7,094	8,093	14,581	18,046
Colorado Electric	15,185		31,688	
Total Residential	32,670	18,095	70,941	41,026
Commercial:				
Black Hills Power	14,551	13,063	29,194	26,535
Cheyenne Light	12,565	11,969	24,626	23,390
Colorado Electric	13,943		27,171	
Total Commercial	41,059	25,032	80,991	49,925
Industrial:				
Black Hills Power	5,030	5,542	9,780	10,838
Cheyenne Light	2,758	2,179	5,291	4,167
Colorado Electric	6,961		15,053	
Total Industrial	14,749	7,721	30,124	15,005
Municipal:				
Black Hills Power	660	639	1,296	1,264
Cheyenne Light	230	240	471	471
Colorado Electric	1,143		2,172	
Total Municipal	2,033	879	3,939	1,735
Contract Wholesale:				
Black Hills Power	5,631	6,270	12,184	13,202
Off-system Wholesale:				
Black Hills Power	5,765	19,238	14,985	34,335
Cheyenne Light	1,952	1,611	3,932	2,871
Colorado Electric	2,974		7,027	
Total Off - system Wholesale	10,691	20,849	25,944	37,206
Other:				
Black Hills Power	4,808	3,224	9,183	6,456
Cheyenne Light	112	108	213	196
Colorado Electric	1,245		1,655	
Total Other	6,165	3,332	11,051	6,652
Total Sales Revenues	$ 112,998	$ 82,178	$ 235,174	$ 164,751

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Quantities Generated and Purchased	Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
	(in MWh)			

Generated				
Coal-fired:				
Black Hills Power	348,657	384,748	786,208	817,630
Cheyenne Light	185,172	201,685	376,728	389,698
Colorado Electric	56,856		123,331	
Total Coal	590,685	586,433	1,286,267	1,207,328
Gas and Oil-fired:				
Black Hills Power	5,750	4,831	6,825	41,831
Cheyenne Light				
Colorado Electric	199		199	
Total Gas and Oil	5,949	4,831	7,024	41,831
Total Generated:				
Black Hills Power	354,407	389,579	793,033	859,461
Cheyenne Light	185,172	201,685	376,728	389,698
Colorado Electric	57,055		123,530	
Total Generated	596,634	591,264	1,293,291	1,249,159
Purchased:				
Black Hills Power	451,191	467,284	884,030	851,865
Cheyenne Light	154,286	124,884	312,273	263,547
Colorado Electric	493,319		980,845	
Total Purchased	1,098,796	592,168	2,177,148	1,115,412
Total Generated and Purchased	1,695,430	1,183,432	3,470,439	2,364,571

Quantity Sold	Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
	(in MWh)			
Residential:				
Black Hills Power	119,123	114,106	282,599	277,140
Cheyenne Light	59,100	57,325	130,226	132,667
Colorado Electric	134,557		277,230	
Total Residential	312,780	171,431	690,055	409,807
Commercial:				
Black Hills Power	169,955	162,313	345,211	335,772
Cheyenne Light	141,555	141,450	287,100	286,767
Colorado Electric	169,698		319,164	
Total Commercial	481,208	303,763	951,475	622,539
Industrial:				
Black Hills Power	93,984	109,028	179,968	211,697
Cheyenne Light	43,425	36,023	86,247	69,771
Colorado Electric	98,603		220,417	
Total Industrial	236,012	145,051	486,632	281,468
Municipal:				
Black Hills Power	7,567	7,637	15,662	15,845
Cheyenne Light	682	742	1,707	1,762
Colorado Electric	10,571		17,991	
Total Municipal	18,820	8,379	35,360	17,607
Contract Wholesale:				
Black Hills Power	143,248	156,965	311,927	328,585
Off-system Wholesale:				
Black Hills Power	230,617	283,770	474,403	511,511
Cheyenne Light	73,947	67,441	144,051	132,413
Colorado Electric	94,865		200,808	
Total Off-system Wholesale	399,429	351,211	819,262	643,924
Total Quantity Sold	1,591,497	1,136,800	3,294,711	2,303,930
Losses and Company Use:				
Black Hills Power	41,104	23,044	67,293	30,776
Cheyenne Light	20,749	23,588	39,670	29,865
Colorado Electric	42,080		68,765	
Total Losses and Company Use	103,933	46,632	175,728	60,641
Total Energy	1,695,430	1,183,432	3,470,439	2,364,571

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Degree Days	Three Months Ended June 30, 2009		2008	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal

Actual				
Black Hills Power	1,273	28%	1,230	23%
Cheyenne Light	1,261	2%	1,306	6%
Colorado Electric	579	(10)%		
Cooling Degree Days:				
Actual				
Black Hills Power	51	(50)%	29	(71)%
Cheyenne Light	24	(43)%	27	(36)%
Colorado Electric	184	(15)%		

Degree Days	Six Months Ended June 30, 2009		2008	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Actual				
Black Hills Power	4,527	5%	4,591	7%
Cheyenne Light	4,085	(7)%	4,542	4%
Colorado Electric	2,949	(10)%		
Cooling Degree Days:				
Actual				
Black Hills Power	51	(50)%	29	(71)%
Cheyenne Light	24	(43)%	27	(42)%
Colorado Electric	184	(15)%		

Electric Utilities Power Plant Availability

	Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
Coal-fired plants	81.8%**	89.0%*	89.5%**	91.5%*
Other plants	92.6%	78.8%	96.0%	86.9%
Total availability	86.0%	85.4%	92.0%	89.9%

* Reflects major maintenance outages at our Ben French, Neil Simpson I and Osage coal-fired plants. The Ben French outage was scheduled for 25 days and was subsequently extended to accelerate major maintenance originally scheduled for 2009. The actual outage was 88 days and resulted in the plant s output being restored to its full rated capacity. The Osage outage was originally scheduled for approximately 10 days and lasted 52 days as a result of additional unplanned required maintenance. All the plants were online by the end of the second quarter of 2008.

** Reflects major maintenance outages at Neil Simpson I and Neil Simpson II coal-fired plants. The Neil Simpson I outage was scheduled for 31 days and was subsequently extended to 39 days. The Neil Simpson II outage was scheduled for 18 days and was subsequently extended to 27 days. The outages were extended on both units for major rotor damage discovered during the overhauls.

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 of these natural gas distribution operations:

	Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
Sales Revenues (in thousands):				
Residential	$ 3,634	$ 6,835	$ 12,646	$ 16,843
Commercial	1,631	3,365	6,060	8,393
Industrial	373	1,355	1,807	3,143
Other	185	197	409	408
Total Sales Revenues	$ 5,823	$ 11,752	$ 20,922	$ 28,787
Sales Margins (in thousands):				
Residential	$ 2,089	$ 2,270	$ 5,366	$ 5,763
Commercial	746	560	1,917	1,838
Industrial	98	127	268	307
Other	185	198	409	422
Total Sales Margins	$ 3,118	$ 3,155	$ 7,960	$ 8,330
Volumes Sold (Dth):				
Residential	553,518	553,018	1,568,764	1,761,111
Commercial	333,213	309,552	917,636	995,824
Industrial	135,790	138,787	383,115	400,742
Total Volumes Sold	1,022,521	1,001,357	2,869,515	3,157,677

Three Months Ended June 30, 2009 Compared to Three Months Ended June 30, 2008. Income from continuing operations for the Electric Utilities decreased $5.0 million from the prior period primarily due to the following:

A $2.8 million decrease in margins from off-system sales reflecting the lower margins available in the industry s current low energy price environment;

A $1.8 million decrease in retail margins primarily due to outages at Neil Simpson I, Neil Simpson II and Wyodak, partially offset by a full quarter of operations at Ben French which had outages in the second quarter of 2008;

A $5.5 million increase in net interest expense due to additional debt associated with the acquisition of Colorado Electric; and

A $1.5 million increase in employee benefit costs.

Partially offsetting these were the following:

Increased margin of $1.9 million related to an increase in transmission rate effective January 1, 2009 at Black Hills Power; and

Increased AFUDC of $1.3 million primarily due to construction of Wygen III and Colorado Electric in 2009.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008. Income from continuing operations for the Electric Utilities decreased $5.9 million from the prior period primarily due to the following:

A $3.8 million decrease in margins from off-system sales reflecting the lower margins available in the industry s current low energy price environment;

An $8.7 million increase in net interest expense due to additional debt associated with the acquisition of Colorado Electric; and

A $2.3 million increase in employee benefit costs.

Partially offsetting these were the following:

Increased gross margins of $3.0 million due to increase in transmission rate effective January 1, 2009 at Black Hills Power; and

Increased AFUDC of $2.9 million due to construction of Wygen III and Colorado Electric in 2009.

Gas Utilities

Operating results for the Gas Utilities are as follows:

	Three Months Ended June 30, 2009 (in thousands)		Six Months Ended June 30, 2009	
Revenue:				
Natural gas regulated	$	86,760	$	335,741
Other non-regulated services		6,578		13,934
Total sales		93,338		349,675
Cost of sales:				
Natural gas regulated		46,601		227,816
Other non-regulated services		3,891		8,461
Total cost of sales		50,492		236,277
Gross margin		42,846		113,398
Operating expenses		37,735		78,912
Operating income	$	5,111	$	34,486
Income from continuing operations and net income available for common stock	$	442	$	17,708

The following table summarizes regulated Gas Utilities sales revenues:

Sales Revenues	Three Months Ended June 30, 2009 (in thousands)	Six Months Ended June 30, 2009
Residential:		
Colorado	$ 10,740	$ 38,150
Nebraska	18,864	78,146
Iowa	16,867	71,411
Kansas	11,182	41,888
Total Residential	57,653	229,595
Commercial:		
Colorado	2,481	8,313
Nebraska	6,364	28,323
Iowa	6,888	32,375
Kansas	3,150	13,566
Total Commercial	18,883	82,577
Industrial:		
Colorado	579	709
Nebraska	577	2,090
Iowa	34	651
Kansas	3,325	4,585
Total Industrial	4,515	8,035
Transportation:		
Colorado	186	362
Nebraska	1,969	5,922
Iowa	944	2,044
Kansas	1,190	2,796
Total Transportation	4,289	11,124
Other:		
Colorado	29	58
Nebraska	539	1,186
Iowa	267	693
Kansas	585	2,473
Total Other	1,420	4,410
Total Regulated	86,760	335,741
Non-regulated Services	6,578	13,934
Total	$ 93,338	$ 349,675

The following table summarizes regulated Gas Utilities sales margins:

Sales Margins	Three Months Ended June 30, 2009 (in thousands)	Six Months Ended June 30, 2009
Residential:		
Colorado	$ 3,567	$ 8,682
Nebraska	8,995	24,130
Iowa	8,597	24,162
Kansas	6,292	15,348
Total Residential	27,451	72,322
Commercial:		
Colorado	649	1,616
Nebraska	2,197	6,941
Iowa	2,194	7,316
Kansas	1,276	3,495
Total Commercial	6,316	19,368
Industrial:		
Colorado	149	184
Nebraska	70	212
Iowa	24	90
Kansas	536	750
Total Industrial	779	1,236
Transportation:		
Colorado	186	362
Nebraska	1,969	5,921
Iowa	945	2,045
Kansas	1,191	2,797
Total Transportation	4,291	11,125
Other:		
Colorado	28	57
Nebraska	539	1,187
Iowa	267	693
Kansas	488	1,937
Total Other	1,322	3,874
Total Regulated	40,159	107,925
Non-regulated Services	2,687	5,473
Total	$ 42,846	$ 113,398

The following table summarizes regulated Gas Utilities volumes sold:

Volumes Sold	Three Months Ended June 30, 2009 (in Dth)	Six Months Ended June 30, 2009
Residential:		
Colorado	1,141,526	3,493,140
Nebraska	1,740,296	7,440,074
Iowa	1,487,113	6,952,670
Kansas	1,062,405	4,009,303
Total Residential	5,431,340	21,895,187
Commercial:		
Colorado	293,801	803,279
Nebraska	865,365	3,201,025
Iowa	911,543	3,734,480
Kansas	408,154	1,529,081
Total Commercial	2,478,863	9,267,865
Industrial:		
Colorado	118,536	130,793
Nebraska	112,284	314,765
Iowa	8,551	90,683
Kansas	811,964	1,001,218
Total Industrial	1,051,335	1,537,459
Transportation:		
Colorado	196,826	431,800
Nebraska	5,830,746	13,414,429
Iowa	3,238,495	7,305,769
Kansas	3,524,951	7,017,578
Total Transportation	12,791,018	28,169,576
Other:		
Colorado		
Nebraska	245	1,135
Iowa	12,335	48,508
Kansas	17,936	77,518
Total Other	30,516	127,161
Total Regulated	21,783,072	60,997,248

Degree Days	Three Months Ended June 30, 2009		Six Months Ended June 30, 2009	
Heating Degree Days:	Actual	Variance From Normal	Actual	Variance From Normal
Colorado	987	13%	3,511	(6)%
Nebraska	566	10%	3,545	(3)%
Iowa	772	9%	4,211	1%
Kansas*	496	2%	2,698	(11)%
Combined Gas Utilities Heating Degree Days	677	(2)%	3,690	(5)%

* Kansas Gas has a 30-year weather normalization adjustment mechanism in place that neutralized the impact of weather on revenues at Kansas Gas.

Results from the Gas Utilities for the three and six month periods ended June 30, 2009 reflect the operations from the gas utilities acquired from Aquila on July 14, 2008.

The Gas Utilities were acquired on July 14, 2008 and, consequently, information for the three and six month periods ended June 30, 2008 is not available. Our Gas Utilities are highly seasonal and sales volumes depend largely on weather and seasonal heating and industrial loads. Approximately 74% of our Gas Utilities revenues are expected in the fourth and first quarters. Therefore, revenues for and certain expenses of, these operations fluctuate significantly among quarters.

Depending upon the state jurisdiction, the winter heating season begins around November 1 and ends around March 31. Margins for the Gas Utilities for the quarter ended June 30, 2009 decreased 39% from the quarter ended March 31, 2009. This decrease was driven by a 62% decrease in residential, commercial and industrial volumes.

Regulatory Matters Utilities Group

The following summarizes our recent rate case activity:

In millions	**Type of Service**	**Date Requested**	**Date Effective**	**Amount Requested**	**Amount Approved**
Nebraska Gas (1)	Gas	11/2006	9/2007	$ 16.3	$ 9.2
Iowa Gas (2)	Gas	6/2008	7/27/09	$ 13.6	$ 10.8
Colorado Gas (3)	Gas	6/2008	4/2009	$ 2.8	$ 1.4
Black Hills Power (4)	Electric	9/2008	1/2009	$ 4.5	$ 3.8
Kansas Gas (5)	Gas	5/2009	Pending	$ 0.5	$ Pending

(1) In November 2006, Nebraska Gas filed for a $16.3 million rate increase. Interim rates were implemented in February 2007 and, in July 2007, the NPSC granted a $9.2 million increase in annual revenues based on an equity return of 10.4% on a capital structure of 51% equity and 49% debt. Nebraska Gas appealed the decision, and the district court affirmed the NPSC order in February 2008. Because Nebraska Gas collected interim rates subject to refund, it was required to refund to customers the difference between the higher interim rates and the final rates plus interest (approximately $5.6 million). The NPA appealed one aspect of our refund plan worth approximately $0.8 million. On April 15, 2009, the District Court affirmed the NPSC refund plan order, and thereby rejected NPA s appeal.

(2) On June 3, 2009, Iowa Gas received approval from the IUB to implement new natural gas service rates for its Iowa residential, commercial and industrial customers. The rates went into effect on July 27, 2009. The approved rates allow Iowa Gas to recover capital investments made in its natural gas distribution system and offset increasing operating costs due to inflation since the last rate increase in March 2006. The new rates represent approximately $10.8 million in additional revenue. The increase is based on a return on equity of 10.1%, with a capital structure of 51.4% equity and 48.6% debt.

(3) In June 2008, Colorado Gas filed for a $2.8 million rate increase. The increase was based on a proposed equity return of 11.5% on a capital structure of 50% equity and 50% debt. Interim rates were not available for collection in Colorado. On September 19, 2008, Colorado Gas filed the second phase of its rate request. On January 29, 2009, a settlement agreement was filed with the CPUC and a settlement was approved with new rates effective on April 1, 2009. The new rates included an increase in annual revenues of $1.4 million, which was based on a 10.25% return on equity with a capital structure of 50.48% equity and 49.52% debt.

(4) On February 10, 2009, the FERC approved a formulaic approach to the method used to determine the revenue component of Black Hills Power s open access transmission tariff, and increased the utility s annual transmission revenue requirement by approximately $3.8 million. The revenue requirement is based on an equity return of 10.8%, and a capital structure consisting of 57% equity and 43% debt. The new rates had an effective date of January 1, 2009.

(5) Kansas Gas has requested a GSRS in the amount of $0.5 million annually. The KCC staff is recommending approval of all projects submitted, the filed GSRS revenue requirement of $0.5 million, and that Kansas Gas be allowed to continue collecting its current GSRS amount of $0.3 million. The KCC has until September 16, 2009 to issue an order.

Non-regulated Energy Group

An analysis of results from our Non-regulated Energy Group s operating segments follows:

Oil and Gas

	Three Months Ended June 30, 2009 (in thousands)	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Revenue	$ 17,829	$ 34,209	$ 34,340	$ 60,331
Operating expenses*	16,246	21,917	78,508	42,407
Operating income (loss)	$ 1,583	$ 12,292	$ (44,168)	$ 17,924
Income (loss) from continuing operations and net income (loss) available for common stock	$ 129	$ 7,197	$ (25,591)	$ 9,749

* Six months ended June 30, 2009 operating expenses include a $43.3 million pre-tax ceiling test impairment charge.

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

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Fuel production:				
Bbls of oil sold	95,900	102,800	195,300	202,800
Mcf of natural gas sold	2,653,600	2,856,800	5,342,500	5,420,000
Mcf equivalent sales	3,229,000	3,473,600	6,514,300	6,636,800

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Average price received: [(a)]				
Gas/Mcf [(b)]	$ 4.39	$ 7.92	$ 4.65[(c)]	$ 7.71[(c)]
Oil/Bbl	$ 58.32	$ 100.31	$ 54.30	$ 90.05
Depletion expense/Mcfe	$ 1.67	$ 2.28	$ 2.09	$ 2.30

(a) Net of hedge settlement gains/losses
(b) Exclusive of gas liquids
(c) Does not include the negative revenue impacts of a $1.2 million and $2.1 million royalty settlement accrual through June 30, 2009 and 2008, respectively, resulting in a $0.24/Mcf and $0.42/Mcf price impact

The following are summaries of LOE/Mcfe:

	Three Months Ended June 30, 2009			Three Months Ended June 30, 2008		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$ 1.18	$ 0.28	$ 1.46	$ 1.37	$ 0.18	$ 1.55
Colorado	1.25	0.37	1.62	1.05	0.88	1.93
Wyoming	1.52		1.52	1.57		1.57
All other properties	0.67	0.26	0.93	0.68	0.20	0.88
All locations	$ 1.17	$ 0.21	$ 1.38	$ 1.24	$ 0.18	$ 1.42

	Six Months Ended June 30, 2009			Six Months Ended June 30, 2008		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$ 1.20	$ 0.27	$ 1.47	$ 1.45	$ 0.31	$ 1.76
Colorado	1.00	0.41	1.41	1.14	0.86	2.00
Wyoming	1.47		1.47	1.68		1.68
All other properties	0.82	0.34	1.16	0.99	0.10	1.09
All locations	$ 1.17	$ 0.23	$ 1.40	$ 1.37	$ 0.21	$ 1.58

Three Months Ended June 30, 2009 Compared to Three Months Ended June 30, 2008. Income from continuing operations decreased $7.1 million for the three months ended June 30, 2009 compared to the same period in 2008 primarily due to:

Revenue decreased $16.4 million due to a 42% decrease in the average hedged price of oil received, a 45% decrease in average hedged price of gas received, and a 7% decrease in production in both oil and gas. The gas production decrease reflects production shut-ins, impact of normal decline curves, and lower levels of capital deployment.

Partially offsetting these were the following:

Decreased depletion and depreciation expense of $2.2 million primarily due to a lower depletion rate reflecting previous ceiling test adjustments and an increase in estimated oil and gas proven reserves as a result of higher commodity prices than those at the end of the first quarter of 2009;

A $3.4 million decrease in production taxes due to lower oil and natural gas prices and lower production.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008. Income from continuing operations decreased $35.3 million for the six months ended June 30, 2009 compared to the same period in 2008 primarily due to:

A $27.8 million after-tax non-cash ceiling test impairment charge for the quarter ended March 31, 2009 due to a ceiling test valuation of our natural gas and crude oil properties resulting from low quarter-end natural gas prices. The write-down of gas and oil properties was based on March 31, 2009 period-end NYMEX prices of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas; and $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil; and

Revenue decreased $26.0 million due to a 40% decrease in the average hedged price of oil received, a 40% decrease in average hedged price of gas received, a 4% decrease in oil production and a 1% decrease in gas production.

Partially offsetting these were the following:

A $1.5 million decrease in LOE as compared to 2008, which was impacted by severe 2008 weather;

A $5.0 million decrease in production taxes due to lower oil and natural gas prices and lower production; and

A $3.8 million income tax benefit related to an adjustment of a previously recorded tax position.

Coal Mining

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Revenue	$ 13,493	$ 12,647	$ 27,895	$ 25,894
Operating expenses	14,488	12,729	28,669	24,346
Operating (loss) income	$ (995)	$ (82)	$ (774)	$ 1,548
(Loss) income from continuing operations and net (loss) income available for common stock	$ (499)	$ 496	$ 319	$ 2,124

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The following table provides certain operating statistics for our Coal Mining segment:

	Three Months Ended June 30, 2009 (in thousands)	2008	Six Months Ended June 30, 2009	2008
Tons of coal sold	1,363	1,453	2,870	2,998
Cubic yards of overburden moved	3,473	2,623	6,635	5,653

Three Months Ended June 30, 2009 Compared to Three Months Ended June 30, 2008.

Income from continuing operations from our Coal Mining segment for the three months ended June 30, 2009 decreased $1.0 million compared to the same period in the prior year. Results were impacted by the following:

Operating expenses increased $1.8 million, or 14%, during the three months ended June 30, 2009 primarily due to increased depreciation expense of $1.4 million due to an increased asset base, and increased coal taxes of $0.9 million due to higher coal prices. Cubic yards of overburden moved increased 32%.

Partially offsetting the increased expenses were the following:

Revenue increased $0.8 million, or 7%, for the three month period ended June 30, 2009 primarily due to an increase in average price received, partially offset by lower volumes sold. The higher average price received includes the impact of regulated sales prices determined in part by a return on investment base; and

Increased operating expenses were offset by lower diesel fuel costs of $0.6 million.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008.

Income from continuing operations from our Coal Mining segment for the six months ended June 30, 2009 decreased $1.8 million compared to the same period in the prior year. Results were impacted by the following:

Operating expenses increased $4.3 million, or 18%, during the six months ended June 30, 2009 primarily due to increased depreciation expense of $3.7 million due to increased equipment usage and an increased asset base, and increased coal taxes of $1.0 million due to higher coal prices. Cubic yards of overburden moved increased 17%.

Partially offsetting the increased expenses were the following:

Revenue increased $2.0 million, or 8%, for the six month period ended June 30, 2009 compared to the same period in 2008 primarily due to an increase in average price received, partially offset by lower volumes sold. The higher average price received includes the impact of regulated sales prices determined in part by a return on investment base; and

Increased operating expenses were offset by lower diesel fuel costs of $1.0 million.

Energy Marketing

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Revenue				
Realized gas marketing gross margin	$ 11,384	$ (5,563)	$ 22,354	$ 7,862
Unrealized gas marketing gross margin	(5,642)	4,151	(6,978)	(2,472)
Realized oil marketing gross margin	5,131	2,755	8,108	4,328
Unrealized oil marketing gross margin	(3,135)	3,807	(8,927)	1,551
	7,738	5,150	14,557	11,269
Operating expenses	4,169	4,544	9,431	10,481
Operating income	$ 3,569	$ 606	$ 5,126	$ 788
Income from continuing operations and net income available for common stock	$ 2,210	$ 365	$ 3,247	$ 664

The following is a summary of average daily volumes marketed:

		Three Months Ended June 30,		Six Months Ended June 30,	
		2009	2008	2009	2008
Natural gas physical sales	MMBtus	1,582,900	1,599,300	1,916,000	1,696,700
Crude oil physical sales	Bbls	11,846	6,896	11,456	6,990

Three Months Ended June 30, 2009 Compared to Three Months Ended June 30, 2008. Income from continuing operations increased $1.8 million for the three months ended June 30, 2009 compared to the same period in 2008, primarily due to:

A $19.3 million increase in realized marketing margins primarily due to differing market conditions. In addition, gross margins from crude oil were higher due to the impact of increasing commodity prices and increased volumes marketed.

Partially offsetting these increases was the following:

A $16.7 million decrease in unrealized marketing margins.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008. Income from continuing operations increased $2.6 million for the six months ended June 30, 2009 compared to the same period in 2008, primarily due to:

An $18.3 million increase in realized marketing margins primarily due to differing market conditions. In addition, gross margins from crude oil were higher due to the impact of increasing commodity prices and increased volumes marketed.

Partially offsetting these increases were the following:

A $15.0 million decrease in unrealized marketing margins; and

Lower operating expenses of $1.0 million primarily due to lower bank fees resulting from lower credit facility utilization.

Power Generation

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Revenue	$ 7,215	$ 8,511	$ 14,834	$ 17,375
Operating expense (gains)	4,347	7,290	(17,779)	14,539
Operating income	$ 2,868	$ 1,221	$ 32,613	$ 2,836
Income (loss) from continuing operations	$ 758	$ (472)	$ 17,911	$ (1,368)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Contracted power plant fleet availability:				
Coal-fired plant	92.4%	93.3%	94.0%	94.2%
Other plants	98.5%	89.5%	98.3%	94.7%
Total availability	94.9%	91.8%	95.7%	94.4%

Three Months Ended June 30, 2009 Compared to Three Months Ended June 30, 2008. Income from continuing operations increased $1.2 million for the three months ended June 30, 2009 compared to the same period in 2008, and was primarily impacted by:

2008 results reflect $6.4 million of allocated indirect corporate costs and inter-segment interest expense related to the IPP assets sold and not reclassified to discontinued operations.

Partially offsetting were the following:

A decrease of $1.0 million reflecting the net earnings impact of replacing the 20 MW power purchase agreement with operating and site lease agreements related to MEAN s purchase of 23.5% ownership interest of Wygen I; and

A $4.1 million increase in net interest expense primarily due to a change in inter-segment debt to equity capital structure.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008. Income from continuing operations increased $19.3 million for the six months ended June 30, 2009 compared to the same period in 2008, and was primarily impacted by:

A $16.9 million after-tax gain on the sale to MEAN of a 23.5% ownership interest in the Wygen I power generation facility. In conjunction with the sale, MEAN will make payments for costs associated with coal supply, plant operations and administrative services. In addition, a 10-year power purchase contract under which MEAN was obligated to buy from us 20 MW of power annually was terminated; and

2008 results reflect $11.8 million of allocated indirect corporate costs and inter-segment interest expense related to the IPP assets sold and not reclassified to discontinued operations.

Partially offsetting were the following:

A decrease of $2.0 million reflecting the net earnings impact of replacing the 20 MW power purchase agreement with operating and site lease agreements related to MEAN s purchase of 23.5% ownership interest of Wygen I; and

A $7.8 million increase in net interest expense primarily due to a change in inter-segment debt to equity capital structure.

Corporate

Three Months Ended June 30, 2009 Compared to Three Months Ended June 30, 2008. Income increased $20.7 million primarily due to unrealized net, mark-to-market gains for the quarter ended June 30, 2009 of approximately $20.6 million after-tax on certain interest rate swaps, partially offset by a $3.0 million after-tax increase in net interest expense. In addition, 2008 results included approximately $1.7 million after-tax for transition and integration costs related to the Aquila Transaction.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008. Income increased $28.1 million primarily due to unrealized net, mark-to-market gains for the six months ended June 30, 2009 of approximately $30.2 million after-tax on certain interest rate swaps, partially offset by a $6.1 million after-tax increase in net interest expense. In addition, 2008 results include $4.2 million after-tax for transition and acquisition costs related to the Aquila Transaction.

Discontinued Operations

Earnings from discontinued operations were $0.8 million for the six month period ended June 30, 2009, compared to $14.1 million for the same period in 2008. The income from discontinued operations in 2009 relates to the final working capital adjustments for the IPP Transaction.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2008 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 2008 Annual Report on Form 10-K.

Liquidity and Capital Resources

Cash Flow Activities

During the six month period ended June 30, 2009, we generated sufficient cash flow from operations to meet our operating needs, fund our property, plant and equipment additions and to pay dividends on our common stock. We received proceeds of $51.9 million for the sale of a 23.5% interest in the Wygen I power plant to MEAN and $32.8 million for the sale to MDU of a 25% interest in the 110 MW Wygen III power plant under construction near Gillette, Wyoming. We plan to fund future property and investment additions including our share of the construction costs of the Wygen III power plant and generation for Colorado Electric from internally generated cash resources and external financings.

Cash flows from operations of $246.2 million for the six month period ended June 30, 2009 represent a $205.0 million increase compared to the same period in the prior year. The increase in cash provided by operating activities for the current period was due to an increase of $25.2 million in our income from continuing operations and changes in working capital as follows:

A $136.6 million increase in cash flows from working capital changes. This increase primarily resulted from a $74.4 million increase in cash flows from decreased net purchases of materials, supplies and fuel and a $197.2 million increase from accounts receivable and other current assets partially offset by a $135.0 million decrease from accounts payable and other current liabilities. Changes in materials, supplies and fuel primarily relate to natural gas held in storage by Energy Marketing and the Gas Utilities which fluctuates based on seasonal trends and economic decisions reflecting current market conditions;

and adjusted for non-cash charges and other items as follows:

A $14.8 million decrease in cash flows related to changes in deferred income taxes which is primarily a result of the deferred tax benefit associated with a non-cash ceiling test impairment charge applicable to our crude oil and natural gas properties;

A $13.3 million increase in cash flows from the net change in derivative assets and liabilities primarily from derivatives associated with normal operations of our oil and gas marketing business and our Oil and Gas segment related to commodity price fluctuations;

A $22.5 million increase in depreciation, depletion and amortization expense;

A $43.3 million non-cash effect from the ceiling test impairment;

A $26.0 million non-cash effect of the gain on sale of operating assets. This gain relates to the sale of the 23.5% interest in the Wygen I power plant to MEAN for which we received $51.9 million included in investing activities;

A $46.5 million non-cash effect of unrealized mark-to-market gains on interest rate swaps; and

A $64.5 million increase in regulatory assets and liabilities primarily resulting from deferred gas adjustments for our Gas Utilities segment.

During the six months ended June 30, 2009, we had cash outflows from investing activities of

$76.7 million, which were primarily due to the following:

Cash outflows of $163.6 million for property, plant and equipment additions. These outflows include approximately $47.4 million related to the construction of our Wygen III power plant, approximately $13.0 million in oil and gas property maintenance capital and development drilling, and approximately $50.3 million of distribution, transmission and generation at our Electric Utilities, which includes new transmission at Colorado Electric and a plant air condenser upgrade at Black Hills Power;

Cash inflows of $51.9 million of proceeds from the sale of the 23.5% interest in the Wygen I power plant to MEAN;

Cash inflows of $32.3 million of proceeds from the sale of the 25% interest in the Wygen III power plant to MDU; and

Cash inflows of $7.7 million for working capital adjustments on the purchase price allocation of the Aquila Transaction.

During the six months ended June 30, 2009, we had net cash outflows from financing activities of $215.7 million resulting from:

$433.3 million net payments on the Corporate Credit Facility and the Acquisition Facility;

$27.5 million of payments of cash dividends on common stock; and

$248.5 million proceeds from issuance of senior unsecured five year notes.

Dividends

Dividends paid on our common stock totaled $27.5 million during the six months ended June 30, 2009, or $0.71 per share. On July 29, 2009, our Board of Directors declared a quarterly dividend of $0.355 per share payable September 1, 2009, which is equivalent to an annual dividend rate of $1.42 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 credit facilities 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. As of June 30, 2009, we had approximately $122.4 million of cash unrestricted for operations.

Corporate Credit Facility

Our $525.0 million revolving credit facility expires on May 4, 2010. The cost of borrowings or letters of credit issued under the facility is determined based on our credit ratings. At our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70 basis points over LIBOR (which equates to a 1.01% one-month borrowing rate as of June 30, 2009).

Our revolving credit facility can be used to fund our working capital needs and for general corporate purposes. At June 30, 2009, we had borrowings of $270.5 million and $43.1 million of letters of credit issued on our revolving credit facility. Available capacity remaining on our revolving credit facility was approximately $211.4 million at June 30, 2009.

The credit facility includes customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions and maintenance of the following financial covenants:

A consolidated net worth in an amount of not less than the sum of $625 million and 50% of our aggregate consolidated net income beginning January 1, 2005;

A recourse leverage ratio not to exceed 0.70 to 1.00 for the first year after the Aquila Transaction and thereafter, a ratio not to exceed 0.65 to 1.00; and

An interest expense coverage ratio of not less than 2.5 to 1.0.

If these covenants are violated, it would be considered an event of default entitling the lenders to terminate the remaining commitment and accelerate all principal and interest outstanding.

In addition to covenant violations, an event of default under the 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 $20 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 or new letters of credit, and could require both the immediate repayment of any principal and interest outstanding and the cash collateralization of outstanding letter of credit obligations.

The credit facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result, after giving effect to such action.

Our consolidated net worth was $1,080.1 million at June 30, 2009, which was approximately $270.5 million in excess of the net worth we were required to maintain under the credit facility. At June 30, 2009, our long-term debt ratio was 40.0%, our total debt leverage ratio (long-term debt and short-term debt) was 48.6%, and our recourse leverage ratio was approximately 53.3%. Our interest expense coverage ratio for the twelve month period ended June 30, 2009 was 4.2 to 1.0.

Public Debt Offering

On May 14, 2009, we issued a $250 million aggregate principal amount of senior unsecured notes due in 2014 pursuant to a public offering. The notes were priced at par and carry a fixed interest rate of 9%. We received proceeds of $248.5 million, net of underwriting fees. Proceeds were used to pay down the Acquisition Facility. Estimated deferred financing costs related to the offering of $2.2 million were capitalized and will be amortized over the life of the debt.

Enserco Credit Facility

On May 8, 2009, Enserco entered into an agreement for a $240 million committed credit facility. Societe Generale, Fortis Capital Corp., and BNP Paribas were co-lead arranger banks. On May 27, 2009, Enserco entered into an agreement for an additional $60 million of commitments under the credit facility with three participating banks: Calyon, Rabobank and RZB Finance. This credit facility expires on May 7, 2010. The facility is a borrowing base line of credit, which allows for the issuance of letters of credit and for borrowings. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. The base rate option borrowing rate is 2.75% plus the higher of: (i) 0.5% above the Federal Funds Rate, or (ii) the prime rate established by Fortis Bank S.A./N.V. The Eurodollar option borrowing rate is 2.75% plus the higher of the Eurodollar Rate or the reference bank cost of funds. Our Enserco credit facility is a borrowing base credit facility, the structure of which requires certain levels of tangible net worth and net working capital to be maintained for a given borrowing base election level. In order to maintain a borrowing base election level, we may be restricted from making dividends from Enserco to the parent company of Enserco. At June 30, 2009, $73.6 million of letters of credit were issued under this facility and there were no cash borrowings outstanding.

Acquisition Facility

In July 2008, in conjunction with the closing of the Aquila Transaction, we borrowed $382.8 million under our $1 billion bridge acquisition credit facility dated May 7, 2007. The Acquisition Facility was structured as a single-draw term loan facility for the sole purpose of financing the Aquila Transaction.

On April 9, 2009, we received proceeds of $30.2 million for the sale of 25% of the Wygen III plant to MDU. The net proceeds were used to pay down a portion of the Acquisition Facility.

On May 14, 2009, we received proceeds from a $250 million public debt offering. The net proceeds were used to pay down a portion of the Acquisition Facility.

On June 15, 2009, we paid off the remaining $104.6 million balance of the Acquisition Facility by borrowing on our Corporate Credit Facility.

Future Financing Plans

We have an effective shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our finance arrangements and restrictions imposed by federal and state regulatory authorities.

We continue to evaluate the debt capital markets and prepare for additional long-term debt issuances to refinance other short-term debt and fund our power generation construction projects. We anticipate issuing a long-term first mortgage bond of approximately $180 million for our electric utility, Black Hills Power, Inc. The offering is expected to be completed in the Fall of 2009; proceeds of the transaction will be used to fund capital expenditures for the utility, including construction costs related to the Wygen III facility, and to fund the approximate $30 million maturity of our Series AC, 8.06% first mortgage bonds due in February 2010.

In the unlikely event we are unable to complete debt financing on acceptable terms, we will consider implementing alternative measures to conserve or raise capital. These alternatives could include deferring our planned capital expenditure program, implementing asset sales, issuing equity, reducing or eliminating our dividend payments, or curtailing certain business activities, including our marketing operations.

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 $250.0 million that are not designated as hedge instruments in accordance with SFAS 133. Accordingly, mark-to-market changes in value on the swaps are recorded within the income statements. For the three and six months ended June 30, 2009, we recorded a $31.7 million and $46.5 million pre-tax unrealized mark-to-market non-cash gain on the swaps. The mark-to-market value on these swaps was a liability of $48.0 million at June 30, 2009. 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 ten and twenty years and have amended mandatory early termination dates ranging from September 30, 2009 to December 29, 2009. We may choose to cash settle these swaps at their fair value prior to their mandatory early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair value on the termination dates.

In addition, we have $150.0 million notional amount floating-to-fixed interest rate swaps, having a maximum term of 7.5 years. These swaps have been designated as cash flow hedges in accordance with SFAS 133 and accordingly, their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the accompanying Condensed Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $16.5 million at June 30, 2009.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2008 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 June 30, 2009, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

Rating Agency	**Rating**	**Outlook**
Moody s	Baa3	Stable
S&P	BBB-	Stable
Fitch	BBB	Stable

In addition, the first mortgage bonds issued by Black Hills Power were rated at June 30, 2009 as follows:

Rating Agency	**Rating**	**Outlook**
Moody s	Baa1	Stable
S&P	BBB	Stable
Fitch	A-	Stable

In August 2009, Moody s upgraded the senior secured debt rating for Black Hills Power to A3.

Capital Requirements

During the six months ended June 30, 2009, capital expenditures were approximately $203.7 million for property, plant and equipment additions, which were partially financed through approximately $40.1 million of accrued liabilities. We currently expect total capital expenditures in 2009 to approximate $365.8 million. This sum includes, but is not limited to: $62.1 million for our share of the Wygen III power plant located near Gillette, Wyoming in which we retain 75% ownership interest in the plant; $73.8 million related to maintenance capital for our new utility properties, and $38.6 million within our Oil and Gas segment primarily for maintenance capital and development drilling.

Actual and forecasted capital requirements for maintenance capital and development capital are as follows:

	Six Months Ended June 30, 2009 Expenditures (in thousands)	Total 2009 Planned Expenditures
Utilities:		
Electric Utilities Wygen III[1]	$ 14,612	$ 62,100
Electric Utilities [2] [3]	73,256	187,568
Gas Utilities	20,449	42,508
Non-regulated Energy:		
Oil and Gas[4]	12,951	38,621
Power Generation	2,696	4,925
Coal Mining	4,963	12,592
Energy Marketing	113	4,135
Corporate	1,769	13,342
	$ 130,809	$ 365,791

(1) Capital expenditures of the Wygen III coal-fired plant are net of $17.2 million of accrued liabilities and $32.8 million proceeds received from the sale to MDU of a 25% interest in the plant. Forecasted expenditures of the Wygen III coal-fired plant reflect our 75% ownership interest in the plant.

(2) Electric Utilities capital requirements include approximately $17.6 million for transmission projects in 2009.

(3) The 2009 total planned expenditures include capital requirements associated with our plans to build gas-fired power generation facilities to serve our Colorado Electric customers. In February 2009, the CPUC authorized Colorado Electric to build two natural gas-fired combustion turbine facilities. We expect to spend capital of $52.3 million in 2009 particularly related to the commitment to purchase the turbine generators from GE. The total construction cost is expected to be approximately $225 million to $275 million to be completed by the end of 2011.

(4) Development capital for our oil and gas properties is expected to be limited to no more than the cash flows produced by those properties. Continued low commodity prices could further reduce our planned development capital expenditures.

As a result of the current global credit crisis we are re-evaluating all of our forecasted capital expenditures, and if determined prudent, 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

Unconditional purchase obligations for firm transportation and storage fees for our Energy Marketing segment increased $6.9 million from $93.5 million at December 31, 2008 to $100.4 million at June 30, 2009. Approximately $62.8 million of the firm transportation and storage fee obligations relate to the 2009-2011 period with the remaining occurring thereafter.

In June 2009, we entered into a ten and a half year lease obligation to relocate our office located in Golden, Colorado to Denver, Colorado. Total obligations over the ten and a half year lease are $14.7 million. This lease contained certain landlord incentives including rent abatement, relocation and tenant finishes.

Guarantees

See Note 6 to our Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

New Accounting Pronouncements

Other than the new pronouncements reported in our 2008 Annual Report on Form 10-K filed with the SEC and those discussed in Notes 2 and 3 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that affect us.

FORWARD-LOOKING INFORMATION

This report 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 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 forward-looking statements include the factors discussed above, the risk factors described in Item 1A. of our 2008 Annual Report on Form 10-K filed with the SEC, and other reports that we file with the SEC from time to time, and the following:

We are evaluating financing options including first mortgage bonds, term loans, project financing and equity issuance. Some important factors that could cause actual results to differ materially from those anticipated include:

§ Our ability to access the bank loan and debt capital markets depends on market conditions beyond our control. If the credit markets remain tight and do not improve, we may not be able to permanently refinance some short-term debt and fund our power generation 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 anticipate that our existing credit capacity and available cash will be sufficient to fund our working capital needs and 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 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.

We expect to make contributions to our defined benefit pension plans of approximately $9.5 million and $16.7 million in 2009 and 2010, 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, sustainable deterioration of the market value of our common stock.

§ Negative regulatory orders or other events that materially impact our Utilities ability to generate stable cash flow over an extended period of time.

We expect to make approximately $365.8 million of capital expenditures in 2009. Some important factors that could cause actual costs to differ materially from those anticipated include:

§ The timing of planned generation, transmission or distribution projects for our Utilities 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 could cause our 2009 forecasted capital expenditures to change.

§ Forecasted capital expenditures associated with our Oil and Gas segment are driven, in part, by current market prices. A continued decline in crude oil and natural gas prices may cause us to change our planned 2009 capital expenditures related to our oil and gas operations.

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 or foreign exchange rates, and the demand for our services, any of which can affect our earnings, our financial liquidity and the underlying value of our assets.

Federal and state laws concerning climate change and air emissions, including emission reduction mandates 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.

The possibility that we may be required to take impairment charges under the SEC s full cost ceiling test for the accumulated costs of our natural gas and oil reserves.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

We produce, purchase and distribute power in four states and purchase and distribute natural gas in five states. All of our gas distribution utilities have PGA provisions that allow them to pass the prudently-incurred cost of gas 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. In South Dakota, Colorado, Wyoming and Montana, we have a mechanism for our electric utilities that serves a purpose similar to the PGAs for our gas utilities. To the extent that our fuel and purchased power energy 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.

The fair value of our Utilities derivative contracts are summarized below (in thousands):

	June 30, 2009	December 31, 2008
Net derivative liabilities	$ (670)	$ (7,444)
Cash collateral	5,792	8,744
	$ 5,122	$ 1,300

Non Regulated Trading Activities

The following table provides a reconciliation of activity in our natural gas and crude oil marketing portfolio that has been recorded at fair value including market value adjustments on inventory positions that have been designated as part of a fair value hedge during the six months ended June 30, 2009 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2008	$	28,447 [(a)]
Net cash settled during the period on positions that existed at December 31, 2008		(25,840)
Unrealized gain on new positions entered during the period and still existing at June 30, 2009		2,164
Realized loss on positions that existed at December 31, 2008 and were settled during the period		(3,477)
Change in cash collateral		25,581
Unrealized gain on positions that existed at December 31, 2008 and still exist at June 30, 2009		10,929
Total fair value of energy marketing positions at June 30, 2009	$	37,804 [(a)]

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(a) The fair value of energy marketing positions consists of derivative assets/liabilities held at fair value in accordance with SFAS 157 and market value adjustments to natural gas inventory that has been designated as a hedged item as part of a fair value hedge in accordance with SFAS 133, as follows (in thousands):

	June 30, 2009	March 31, 2009	December 31, 2008
Net derivative assets (liabilities)	$ 32,352	$ 39,843	$ 54,117
Cash collateral	9,267	(3,673)	(16,315)
Market adjustment recorded in material, supplies and fuel	(3,815)	(2,399)	(9,355)
	$ 37,804	$ 33,771	$ 28,447

GAAP restricts mark-to-market accounting treatment primarily to only those contracts that meet the definition of a derivative under SFAS 133. Therefore, the above reconciliation does not present a complete picture of our overall portfolio of trading activities or our expected cash flows from energy trading activities. In our natural gas and crude oil marketing operations, we often employ strategies that include utilizing derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, SFAS 133 generally does not allow us to mark our inventory, transportation or storage positions to market. The result is that while a significant majority of our energy marketing positions are fully economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions should be expected given these accounting requirements.

To value the assets and liabilities for our outstanding derivative contracts, we use the fair value methodology outlined in SFAS 157. See Note 3 of the Notes to Consolidated Financial Statements in our 2008 Annual Report on Form 10-K and Note 12, Note 13 and Note 14 of the accompanying Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

The sources of fair value measurements were as follows (in thousands):

Source of Fair Value of Energy Marketing Positions	Maturities Less than 1 year	1 2 years	Total Fair Value
Cash collateral	$ 9,267	$	$ 9,267
Level 2	25,696	3,749	29,445
Level 3	3,122	(215)	2,907
Market value adjustment for inventory (see footnote (a) above)	(3,815)		(3,815)
Total fair value of our energy marketing positions	$ 34,270	$ 3,534	$ 37,804

The following table presents a reconciliation of our June 30, 2009 energy marketing positions recorded at fair value under GAAP to a non-GAAP measure of the fair value of our energy marketing forward book wherein all forward trading positions are marked-to-market (in thousands):

Fair value of our energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$ 37,804
Market value adjustments for inventory, storage and transportation positions that are part of our forward trading book, but that are not marked-to-market under GAAP	(6,734)
Fair value of all forward positions (non-GAAP)	31,070
Cash collateral included in GAAP marked-to-market fair value	(9,267)
Fair value of all forward positions excluding cash collateral (non-GAAP)	$ 21,803

There have been no material changes in market risk compared to those reported in our 2008 Annual Report on Form 10-K filed with the SEC. For more information on market risk, see Part II, Items 7 and 7A. in our 2008 Annual Report on Form 10-K, and Note 12 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Activities Other Than Trading

We have entered into agreements to hedge a portion of our estimated 2009, 2010 and 2011 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place are as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term		Volume (MMBtu/day)	Price
San Juan El Paso	07/27/2007	Swap	07/09	09/09	5,000	$ 7.63
CIG	09/07/2007	Swap	07/09	09/09	1,500	$ 6.48
AECO	09/07/2007	Swap	04/08	10/09	1,000	$ 6.89
San Juan El Paso	10/29/2007	Swap	07/09	09/09	5,000	$ 7.38
San Juan El Paso	10/29/2007	Swap	10/09	12/09	5,000	$ 7.53
CIG	10/29/2007	Swap	10/09	12/09	1,500	$ 7.07
NWR	11/16/2007	Swap	01/09	12/09	1,500	$ 6.87
San Juan El Paso	12/13/2007	Swap	10/09	12/09	1,500	$ 7.39
San Juan El Paso	12/13/2007	Swap	10/09	12/09	1,500	$ 7.41
CIG	01/03/2008	Swap	01/10	03/10	2,000	$ 7.49
NWR	01/03/2008	Swap	01/10	03/10	1,500	$ 7.50
AECO	01/03/2008	Swap	11/09	03/10	1,000	$ 8.07
San Juan El Paso	01/23/2008	Swap	01/10	03/10	5,000	$ 7.50
San Juan El Paso	02/28/2008	Swap	01/10	03/10	3,000	$ 8.55
San Juan El Paso	04/09/2008	Swap	04/10	06/10	5,000	$ 7.26
San Juan El Paso	04/30/2008	Swap	04/10	06/10	2,500	$ 7.65
AECO	08/20/2008	Swap	04/10	06/10	1,000	$ 7.73
San Juan El Paso	08/20/2008	Swap	07/10	09/10	5,000	$ 7.74
AECO	08/20/2008	Swap	07/10	09/10	1,000	$ 7.88
AECO	10/24/2008	Swap	10/10	12/10	1,000	$ 7.05
San Juan El Paso	12/19/2008	Swap	10/09	12/09	1,000	$ 5.12
San Juan El Paso	12/19/2008	Swap	04/10	06/10	1,500	$ 5.39
San Juan El Paso	12/19/2008	Swap	07/10	09/10	3,000	$ 5.95
San Juan El Paso	12/19/2008	Swap	10/10	12/10	5,000	$ 5.89
CIG	01/26/2009	Swap	04/10	06/10	2,000	$ 4.45
CIG	01/26/2009	Swap	07/10	09/10	2,000	$ 4.47
CIG	01/26/2009	Swap	10/10	12/10	2,000	$ 4.68
CIG	01/26/2009	Swap	01/11	03/11	2,000	$ 6.00
NWR	01/26/2009	Swap	01/11	03/11	2,000	$ 6.05
San Juan El Paso	01/26/2009	Swap	01/11	03/11	5,000	$ 6.38
San Juan El Paso	02/13/2009	Swap	01/11	03/11	2,500	$ 6.16
San Juan El Paso	02/13/2009	Swap	10/10	12/10	3,000	$ 5.35
NWR	02/13/2009	Swap	04/10	12/10	1,000	$ 4.20
AECO	03/04/2009	Swap	01/11	03/11	1,000	$ 5.95
NWR	03/04/2009	Swap	07/09	09/09	1,000	$ 3.07
NWR	03/04/2009	Swap	04/10	06/10	1,000	$ 4.06
NWR	03/04/2009	Swap	07/10	09/10	1,000	$ 4.12
NWR	03/04/2009	Swap	10/10	12/10	1,000	$ 4.55
NWR	03/20/2009	Swap	01/10	03/10	500	$ 4.58
San Juan El Paso	03/20/2009	Swap	01/10	03/10	1,000	$ 4.87
San Juan El Paso	06/02/2009	Swap	04/11	06/11	5,000	$ 5.99
San Juan El Paso	06/02/2009	Swap	10/09	12/09	1,500	$ 4.14
AECO	06/02/2009	Swap	04/11	06/11	800	$ 5.89
NWR	06/02/2009	Swap	10/09	12/09	500	$ 3.95
NWR	06/02/2009	Swap	04/11	06/11	1,500	$ 5.54

San Juan El Paso	06/25/2009	Swap	04/11	06/11	2,500	$ 5.55
CIG	06/25/2009	Swap	04/11	06/11	1,750	$ 5.33

Crude Oil

Location	Transaction Date	Hedge Type	Term		Volume (Bbls/month)	Price
NYMEX	06/22/2007	Swap	07/09	09/09	5,000	$ 72.10
NYMEX	07/27/2007	Put	07/09	09/09	5,000	$ 65.00
NYMEX	09/12/2007	Swap	07/09	09/09	5,000	$ 71.20
NYMEX	10/29/2007	Put	10/09	12/09	5,000	$ 75.00
NYMEX	10/29/2007	Swap	10/09	12/09	5,000	$ 80.75
NYMEX	11/16/2007	Put	07/09	09/09	5,000	$ 75.00
NYMEX	11/16/2007	Put	10/09	12/09	5,000	$ 75.00
NYMEX	01/03/2008	Put	01/10	03/10	5,000	$ 80.00
NYMEX	01/03/2008	Swap	01/10	03/10	5,000	$ 88.70
NYMEX	01/23/2008	Swap	10/09	12/09	5,000	$ 83.10
NYMEX	01/23/2008	Swap	01/10	03/10	5,000	$ 82.90
NYMEX	02/28/2008	Put	01/10	03/10	5,000	$ 85.00
NYMEX	04/09/2008	Swap	04/10	06/10	5,000	$ 99.60
NYMEX	04/30/2008	Put	04/10	06/10	5,000	$ 85.00
NYMEX	05/29/2008	Put	04/10	06/10	5,000	$ 105.00
NYMEX	07/16/2008	Swap	04/10	06/10	5,000	$ 135.10
NYMEX	07/16/2008	Swap	07/10	09/10	5,000	$ 134.90
NYMEX	08/20/2008	Put	07/10	09/10	5,000	$ 90.00
NYMEX	09/03/2008	Put	07/10	09/10	5,000	$ 90.00
NYMEX	10/24/2008	Put	07/10	09/10	5,000	$ 60.00
NYMEX	12/05/2008	Swap	10/10	12/10	5,000	$ 65.20
NYMEX	01/26/2009	Swap	10/10	12/10	5,000	$ 60.15
NYMEX	01/26/2009	Swap	01/11	03/11	5,000	$ 60.90
NYMEX	02/13/2009	Swap	01/11	03/11	5,000	$ 60.05
NYMEX	03/04/2009	Swap	10/10	12/10	5,000	$ 55.80
NYMEX	03/04/2009	Swap	01/11	03/11	5,000	$ 57.00
NYMEX	04/08/2009	Swap	04/11	06/11	5,000	$ 68.80
NYMEX	04/23/2009	Swap	04/11	06/11	5,000	$ 65.10
NYMEX	06/02/2009	Swap	10/10	12/10	5,000	$ 74.30
NYMEX	06/02/2009	Swap	01/11	03/11	5,000	$ 75.05
NYMEX	06/02/2009	Swap	04/11	06/11	5,000	$ 75.86
NYMEX	06/04/2009	Put	04/11	06/11	5,000	$ 67.00

ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) as of June 30, 2009. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

There have been no changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2009 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting. On July 14, 2008, we acquired the assets of Aquila s regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa (the Acquired Businesses). The internal controls of the Acquired Businesses are an area of focus for us. We are in the process of reviewing the internal controls of the Acquired Businesses and making any necessary changes. As permitted by the guidance set forth by the Securities and Exchange Commission, the Acquired Businesses were not included in management s assessment of internal control over financial reporting for the year ended December 31, 2008.

Our assessment of the effectiveness of our internal controls over financial reporting as of June 30, 2009 excluded the assets and operations acquired on July 14, 2008 in the Aquila Transaction, which are doing business as Black Hills Energy. Such exclusion was in accordance with SEC guidance that an assessment of a recently acquired business may be omitted in management s report on internal control over financial reporting, provided the acquisition took place within twelve months of management s evaluation. Collectively, Black Hills Energy comprised 36% of our consolidated assets at June 30, 2009, and for the six months ended June 30, 2009 62% of our consolidated revenues and 25% of our net income. Our disclosure controls and procedures were not materially impacted by the acquisition.

Part II Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 18 in Item 8 of our 2008 Annual Report on Form 10-K and Note 15 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 15 is incorporated by reference into this item.

Item 1A. Risk Factors

Except to the extent updated or described below, our Risk Factors are documented in Item IA. of Part I in our Annual Report on Form 10-K for the year ended December 31, 2008.

Federal and state laws concerning climate change and air emissions, including emission reduction mandates 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.

We own and operate regulated and non-regulated fossil-fuel generating plants in South Dakota, Wyoming, Colorado and Idaho. We are constructing another fossil-fuel generating plant in Wyoming. Air emissions of fossil-fuel generating plants are subject to federal, state and tribal regulation. Recent developments under federal and state laws and regulation governing air emissions from fossil-fuel generating plants will likely result in more stringent emission limitations.

On April 2, 2007, the U.S. Supreme Court issued a decision in the case of Massachusetts v. U.S. Environmental Protection Agency, holding that CO2 and other GHG emissions are pollutants subject to regulation under the motor vehicle provisions of the Clean Air Act. The case was remanded to the EPA for further rulemaking to determine whether GHG emissions may reasonably be anticipated to endanger public health or welfare, or alternatively, to explain why GHG emissions should not be regulated. On April 17, 2008, the EPA issued its proposed endangerment finding under Section 202 of the Clean Air Act. Although this proposal does not specifically address stationary sources, such as power generation plants, the general endangerment finding relative to GHG s could support such a proposal by the EPA for stationary sources. On March 10, 2009, the EPA released proposed rules regarding a mandatory GHG reporting regimen, the purpose of which would be to collect data to inform future policy and regulatory decisions. Finally, federal legislation is currently under consideration in the U.S. Congress, including H.R. 2454, the American Clean Energy and Security Act of 2009 , which was approved by the U.S. House of Representatives on June 26, 2009. This legislation would affect electric generation and electric and natural gas distribution companies. H.R. 2454 would establish mandatory GHG reduction targets, utilizing a Federal emissions cap-and-trade program. H.R.2454 also proposes a national renewable electricity standard, which would implement a phased process ultimately mandating that 20% of electricity sold by retail suppliers be met by energy efficiency improvements and renewable energy resources by 2020. The Senate is expected to consider its own version of the legislation later in 2009 or in 2010.

Due to the uncertainty as to the final outcome of federal climate change legislation, or regulatory changes under the Clean Air Act, we cannot definitively estimate the effect of GHG regulation on our results of operations, cash flows or financial position. The impact of GHG legislation or regulation upon our company will depend upon many factors, including but not limited to the timing of implementation, the GHG sources that are regulated, the overall GHG emissions cap level, and the availability of technologies to control or reduce GHG emissions. If a cap and trade structure is implemented, the impact will also be affected by the degree to which offsets are allowed, the allocation of emission allowances to specific sources, and the affect of carbon regulation on natural gas and coal prices.

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

We own electric utilities that serve customers in Colorado, Montana, South Dakota and Wyoming. To varying degrees, Colorado and Montana have each adopted mandatory renewable portfolio standards that require electric utilities to supply a minimum percentage of the power delivered to customers from renewable resources (e.g., wind, solar, biomass) by a certain date in the future. These renewable energy portfolio standards have increased the power supply costs of our electric operations. If these states increase their renewable energy portfolio standards, or if similar standards are imposed by the other states in which we operate electric utilities, our power supply costs will further increase. Although we will seek to recover these higher costs in rates, any unrecovered costs could have a material negative impact on our results of operations and financial condition.

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

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
April 1, 2009 April 30, 2009	415 (1)	$ 19.00		
May 1, 2009 May 31, 2009		$		
June 1, 2009 June 30, 2009		$		
Total	415	$ 19.00		

(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 and the distribution of vested restricted stock units.

Item 4. Submission of Matters to a Vote of Security Holders

(a) The Annual Meeting of Shareholders was held on May 19, 2009.

(b) Matters Voted Upon at the Meeting

1. Elected three Class III Directors to serve until the Annual Meeting of Shareholders in 2012.

David C. Ebertz	
Votes For	29,879,847
Votes Withheld	5,267,115
John R. Howard	
Votes For	29,783,428
Votes Withheld	5,363,534
Stephen D. Newlin	
Votes For	30,106,421
Votes Withheld	5,040,541

2. Ratified the appointment of Deloitte & Touche LLP to serve as Black Hills Corporation s independent auditors in 2009.

Votes For	34,628,264
Votes Against	382,210
Abstain	136,488

Item 6. Exhibits

Exhibit 4	Second Supplemental Indenture dated as of May 14, 2009, between the Registrant and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4 to the Registrant s Form 8-K filed on May 14, 2009).
Exhibit 10	Joinder Agreements dated May 27, 2009 to the Third Amended and Restated Credit Agreement effective May 7, 2009, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, and Calyon New York Branch, Cooperatieve Centrale Raiffeisen-Boerenleenbank B.A. Rabobank Nederland, New York Branch and RZB Finance LLC (filed as Exhibits 10.1, 10.2 and 10.3 to the Registrant s Form 8-K filed on May 28, 2009).
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.

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: August 10, 2009

EXHIBIT INDEX

Exhibit Number	Description
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