BLACK HILLS CORP /SD/
Form 10-Q
May 11, 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 March 31, 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 April 30, 2009
Common stock, $1.00 par value	38,798,483 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
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, Inc., 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
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	FASB Interpretation No. 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
FIN 48	FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109
FSP	FASB Staff Position
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 157-2	FSP FAS 157-2, Effective Date of FASB Statement No. 157
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.
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
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
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 March 31, 2009	2008
	(in thousands, except per share amounts)	
Operating revenues	$ 437,943	$ 152,850
Operating expenses:		
Fuel and purchased power	261,020	52,395
Operations and maintenance	39,335	21,966
Gain on sale of assets	(25,971)	
Administrative and general	41,766	24,059
Depreciation, depletion and amortization	33,325	19,386
Taxes, other than income taxes	11,698	9,508
Impairment of long-lived assets	43,301	
	404,474	127,314
Operating income	33,469	25,536
Other income (expense):		
Interest expense	(18,901)	(9,194)
Interest rate swap unrealized gain	14,763	
Interest income	528	426
Allowance for funds used during construction equity	1,372	281
Other income, net	744	336
	(1,494)	(8,151)
Income from continuing operations before equity in (loss) earnings of unconsolidated subsidiaries and income taxes	31,975	17,385
Equity in (loss) earnings of unconsolidated subsidiaries	(327)	232
Income tax expense	(6,023)	(5,801)
Income from continuing operations	25,625	11,816
Income from discontinued operations, net of taxes	766	5,052
Net income	26,391	16,868
Net loss attributable to non-controlling interest		(77)
Net income available for common stock	$ 26,391	$ 16,791
Weighted average common shares outstanding:		
Basic	38,511	37,826
Diluted	38,563	38,399
Earnings per share:		
Basic		
Continuing operations	$ 0.67	$ 0.31
Discontinued operations	0.02	0.13
Total	$ 0.69	$ 0.44
Diluted		
Continuing operations	$ 0.66	$ 0.31
Discontinued operations	0.02	0.13

Total	$ 0.68	$ 0.44
Dividends paid per share of common stock	$ 0.355	$ 0.35

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)

	March 31, 2009	December 31, 2008	March 31, 2008
	(in thousands, except share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 121,562	$ 168,491	$ 71,027
Restricted cash			5,484
Short-term investments			7,290
Receivables (net of allowance for doubtful accounts of $7,832; $6,751 and $4,213, respectively)	233,921	357,404	254,178
Materials, supplies and fuel	59,139	118,021	80,533
Derivative assets	79,443	73,068	46,337
Income tax receivable		20,269	
Deferred income taxes	11,788	10,244	14,011
Regulatory assets	19,053	35,390	2,659
Other current assets	11,517	16,380	11,779
Assets of discontinued operations		246	590,687
	536,423	799,513	1,083,985
Investments	19,956	22,764	16,745
Property, plant and equipment	2,750,760	2,705,492	1,903,096
Less accumulated depreciation and depletion	(750,748)	(683,332)	(526,729)
	2,000,012	2,022,160	1,376,367
Other assets:			
Goodwill	359,093	359,290	14,000
Intangible assets, net	4,870	4,884	3
Derivative assets	11,606	9,799	1,360
Regulatory assets	137,108	143,705	18,553
Other	12,041	17,774	14,054
	524,718	535,452	47,970
	$ 3,081,109	$ 3,379,889	$ 2,525,067
LIABILITIES AND STOCKHOLDERS EQUITY			
Current liabilities:			
Accounts payable	$ 191,817	$ 288,907	$ 238,955
Accrued liabilities	129,405	134,940	84,597
Derivative liabilities	105,883	118,657	72,526
Accrued income taxes	19,794		303
Regulatory liabilities	14,939	5,203	4,804
Notes payable	479,800	703,800	73,000
Current maturities of long-term debt	32,082	2,078	130,330
Liabilities of discontinued operations		88	90,001
	973,720	1,253,673	694,516
Long-term debt, net of current maturities	471,226	501,252	503,279
Deferred credits and other liabilities:			
Deferred income taxes	222,157	223,607	209,272
Derivative liabilities	20,656	22,025	16,516
Regulatory liabilities	39,514	38,456	29,379
Benefit plan liabilities	160,397	159,034	42,244
Other	121,842	131,306	59,379
	564,566	574,428	356,790
Stockholders equity:			
Common stock equity			
Common stock $1 par value; 100,000,000 shares authorized; Issued 38,796,005; 38,676,054 and 38,425,006 shares, respectively	38,796	38,676	38,425
Additional paid-in capital	585,244	584,582	578,742
Retained earnings	460,091	447,453	400,909
Treasury stock at cost 4,725; 40,183 and 29,400			

shares, respectively	(119)	(1,392)	(1,050)
Accumulated other comprehensive loss	(12,415)	(18,783)	(51,788)
Total common stockholders equity	1,071,597	1,050,536	965,238
Non-controlling interest in subsidiaries			5,244
Total equity	1,071,597	1,050,536	970,482
	$ 3,081,109	$ 3,379,889	$ 2,525,067

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)

	Three Months Ended March 31, 2009	2008
	(in thousands)	
Operating activities:		
Net income	$ 26,391	$ 16,868
Income from discontinued operations, net of taxes	(766)	(5,052)
Income from continuing operations	25,625	11,816
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	33,325	19,386
Impairment of long-lived assets	43,301	
Net change in derivative assets and liabilities	6,154	7,745
Gain on sale of operating assets	(25,971)	
Unrealized mark-to-market gain on interest rate swaps	(14,763)	
Deferred income taxes	(5,427)	8,830
Distributed earnings in associated companies	2,687	1,241
Allowance for funds used during construction equity	(1,372)	(281)
Change in operating assets and liabilities:		
Materials, supplies and fuel	65,838	22,390
Accounts receivable and other current assets	123,993	(22,430)
Accounts payable and other current liabilities	(83,994)	(8,742)
Regulatory assets and liabilities	33,027	(266)
Other operating activities	(2,971)	(1,937)
Net cash provided by operating activities of continuing operations	199,452	37,752
Net cash provided by operating activities of discontinued operations	883	15,929
Net cash provided by operating activities	200,335	53,681
Investing activities:		
Property, plant and equipment additions	(71,272)	(56,547)
Proceeds from sale of business operations	51,878	
Working capital adjustment of purchase price allocation on acquisition	7,900	
Increase in short-term investments		(7,290)
Other investing activities	135	951
Net cash used in investing activities of continuing operations	(11,359)	(62,886)
Net cash used in investing activities of discontinued operations		(17,742)
Net cash used in investing activities	(11,359)	(80,628)
Financing activities:		
Dividends paid	(13,753)	(13,275)
Common stock issued	764	1,998
Increase (decrease) in short-term borrowings, net	(224,000)	36,000
Long-term debt repayments	(22)	(18)
Other financing activities	1,065	297
Net cash (used in) provided by financing activities of continuing operations	(235,946)	25,002
Net cash used in financing activities of discontinued operations		(3,214)
Net cash (used in) provided by financing activities	(235,946)	21,788
Decrease in cash and cash equivalents	(46,970)	(5,159)
Cash and cash equivalents:		
Beginning of period	168,532[a]	81,255[b]
End of period	$ 121,562	$ 76,096[c]
Supplemental disclosure of cash flow information:		
Non-cash investing and financing activities-		
Property, plant and equipment acquired with accrued liabilities	$ 28,947	$ 18,939
Cash paid during the period for-		
Interest (net of amounts capitalized)	$ 10,177	$ 7,333
Income taxes paid (net of amounts refunded)	$ (24,495)	$ 1,500

(a) Includes less than $0.1 million of cash included in the assets of discontinued operations.
(b) Includes approximately $4.4 million of cash included in the assets of discontinued operations.
(c) Includes approximately $5.1 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 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.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying financial statements reflects all adjustments which are, in the opinion of management, necessary for a fair presentation of the March 31, 2009, December 31, 2008 and March 31, 2008 financial information and are of a normal recurring nature. Some of our operations 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. The results of operations for the three months ended March 31, 2009, are not necessarily indicative of the results to be expected for the full year. 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 March 31, 2008. See Note 20 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 17 for additional information.

(2) RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

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 13.

FSP FAS 157-2

In February 2008, the FASB issued FSP FAS 157-2, which permits a one-year deferral of the application of SFAS 157 for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We adopted FSP FAS 157-2 effective January 1, 2008. Accordingly, the provisions of SFAS 157 were not applied to non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis, until January 1, 2009. We adopted the provisions of SFAS 157 for non-financial assets and non-financial liabilities upon the expiration of FSP FAS 157-2 and it did not have an impact on our consolidated financial statements.

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 are settled for an amount other than as previously recorded prior to the adoption of SFAS 141(R), the reversal of any remaining liability will affect 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.

SFAS 160

In December 2007, the FASB issued SFAS 160. SFAS 160 amends ARB 51 and requires:

Ownership interests in subsidiaries held by parties other than the parent be clearly identified on the consolidated statement of financial position within equity, but separate from the parent s equity;

Consolidated net income attributable to the parent and to the non-controlling interest be clearly identified on the face of the consolidated statement of income;

Changes in a parent s ownership interest while the parent retains a controlling financial interest be accounted for consistently as equity transactions;

When a subsidiary is deconsolidated, any retained non-controlling equity investment in the former subsidiary be initially measured at fair value; and

Sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners.

We applied the provisions of SFAS 160 on January 1, 2009. Non-controlling interest in the accompanying Condensed Consolidated Statement of Income and Balance Sheet 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 effect overall.

SFAS 161

In March 2008, the FASB issued SFAS 161, which requires enhanced disclosures about how derivative and hedging activities affect 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 evaluated and applied the provisions of SFAS 161 on January 1, 2009. Our contracts do not include credit risk-related contingent features. The additional disclosures are provided in Note 12 and Note 14.

(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 not permitted. We are currently assessing the impact that the adoption will have on our disclosures, operating results, financial position and cash flows.

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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 and we will adopt as of January 1, 2010. We do not expect the adoption of FSP FAS 132(R)-1 to have a significant effect on our consolidated financial statements.

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 will be required.

We are currently assessing the impact that the adoption will have on our disclosures, operating results, financial position and cash flows.

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 will require public companies to provide more frequent disclosures about the fair value of their financial instruments. We are currently assessing the impact that the adoption will have on our disclosures.

(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	March 31, 2009	December 31, 2008	March 31, 2008
Materials and supplies	$ 34,574	$ 32,580	$ 28,384
Fuel Electric Utilities	7,270	10,058	1,749
Natural gas in storage Gas Utilities	7,590	59,529	
Gas and oil held by Energy Marketing*	9,705	15,854	50,400
Total materials, supplies and fuel	$ 59,139	$ 118,021	$ 80,533

* As of March 31, 2009, December 31, 2008 and March 31, 2008, market adjustments related to natural gas held by Energy Marketing and recorded in inventory were $(2.4) million, $(9.4) million and $4.6 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 sales date in the future.

(5) NOTES PAYABLE AND LONG-TERM DEBT

Acquisition Credit 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 March 31, 2009 outstanding balance of $382.8 million, is included in Notes payable in the accompanying Condensed Consolidated Balance Sheets. In April 2009, we received proceeds of $30.2 million for the partial sale of the Wygen III plant. These proceeds were used to pay down a portion of the Acquisition Facility (see Note 21).

(6) GUARANTEES

On January 19, 2009, we issued a guarantee for up to $37.9 million to GE for payment obligations arising from a contract to purchase one LMS100 natural gas turbine generator by Colorado Electric, which is expected to be used in meeting the needs of our Colorado Electric customers. It is a continuing guarantee which terminates upon payment in full of the purchase price to GE. Payments are scheduled based upon estimated milestone dates with the final payment due September 29, 2010. The purchase contract also gives us a short-term option for the purchase of two additional LMS100 turbine generators at the same pricing as the first generator.

On January 20, 2009, we guaranteed a surety bond for $9.2 million to MEAN to secure the 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 March 31, 2009	Three Months	
	Income	Average Shares
Income from continuing operations	$ 25,625	
Basic earnings	25,625	38,511
Dilutive effect of:		
Restricted stock		52
Diluted earnings	$ 25,625	38,563

Period ended March 31, 2008	Three Months	
	Income	Average Shares
Income from continuing operations	$ 11,816	
Basic earnings	11,816	37,826
Dilutive effect of:		
Stock options		80
Estimated contingent shares issuable for prior acquisition		397
Restricted stock		78
Others		18
Diluted earnings	$ 11,816	38,399

(8) OTHER COMPREHENSIVE INCOME

The following table presents the components of our other comprehensive income

(in thousands):

	Three Months Ended March 31, 2009	2008
Net income	$ 26,391	$ 16,868
Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $(1,144) and $14,951, respectively)	2,998	(27,433)
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $(1,917) and $(152), respectively)	3,370	273
Unrealized loss on available for sale securities (net of tax of $65)		(120)
Total comprehensive income (loss)	32,759	(10,412)
Less comprehensive income attributable to non-controlling interest		(77)
Comprehensive income attributable to Black Hills Corporation	$ 32,759	$ (10,489)

Other comprehensive income from fair value adjustments on derivatives designated as cash flow hedges in the three months ended March 31, 2009 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 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 March 31, 2009	$ 1,818	$ (14,127)	$ (106)	$	$ (12,415)
As of December 31, 2008	$ (4,522)	$ (14,127)	$ (134)	$	$ (18,783)
As of March 31, 2008	$ (45,379)	$ (6,115)	$ (174)	$ (120)	$ (51,788)

(9) COMMON STOCK

Other than the following transactions, we had no other 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 shareholder 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 47,202 shares of common stock under the 2008 short-term incentive compensation plan during the three months ended March 31, 2009. Pre-tax compensation cost related to the award was approximately $1.6 million, which was accrued for in 2008.

We granted 78,877 restricted common shares during the three months ended March 31, 2009. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $2.1 million will be recognized over the three-year vesting period.

No stock options were exercised during the three months ended March 31, 2009.

Total compensation expense recognized for all equity compensation plans for the three months ended March 31, 2009 and 2008 was $0.4 million and $0.2 million, respectively.

As of March 31, 2009, total unrecognized compensation expense related to non-vested stock awards was $7.7 million and is expected to be recognized over a weighted-average period of 2.4 years.

Dividend Reinvestment and Stock Purchase Plan

We have a Dividend Reinvestment and Stock Purchase Plan under which shareholders 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 39,833 open market shares at a weighted-average price of $17.07 during the three months ended March 31, 2009. At March 31, 2009, 399,482 shares of unissued common stock were available for future offering under the Plan.

(10) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

We have three non-contributory defined benefit pension plans (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.

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

	Three Months Ended March 31, 2009	2008
Service cost	$ 1,929	$ 754
Interest cost	3,679	1,230
Expected return on plan assets	(3,458)	(1,573)
Prior service cost	41	41
Net loss	752	
Net periodic benefit cost	$ 2,943	$ 452

We made a $0.1 million contribution to the Cheyenne Light Pension Plan and a $0.4 million contribution to the Black Hills Corporation Pension Plan in the first quarter of 2009; no contributions were made to the Black Hills Energy Plan during the first three months of 2009. Additional contributions anticipated to be made to the Plans for 2009 and 2010 are expected to be approximately $14.4 million and $16.7 million, respectively.

Supplemental Non-qualified Defined Benefit Plans

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

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

	Three Months Ended March 31, 2009	2008
Service cost	$ 117	$ 112

Interest cost	344	311
Prior service cost	1	3
Net loss	147	142
Net periodic benefit cost	$ 609	$ 568

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.

Non-pension Defined Benefit Postretirement Healthcare Plans

Employees who are participants in our Postretirement Healthcare Plans (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 March 31, 2009	2008
Service cost	$ 260	$ 125
Interest cost	542	217
Expected return on asset	(56)	
Prior service cost	(22)	
Net transition obligation	15	15
Net gain	(8)	(20)
Net periodic benefit cost	$ 731	$ 337

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 for each of the three month periods ended March 31, 2009 and 2008.

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

Our reportable segments are those that 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 March 31, 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.

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

Three Month Period Ended March 31, 2009	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$ 137,060	$ 215	$ 9,317
Gas Utilities	256,337		17,265
Non-regulated Energy:			
Oil and Gas	16,511		(25,720)
Power Generation	7,619		17,153
Coal Mining	7,937	6,465	819
Energy Marketing	6,820		1,037
Corporate			5,536
Inter-segment eliminations		(1,021)	218
Total	$ 432,284	$ 5,659	$ 25,625

Three Month Period Ended March 31, 2008	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$ 99,302	$ 306	$ 10,167
Non-regulated Energy:			
Oil and Gas	26,122		2,551
Power Generation	2,313	6,551	(896)
Coal Mining	7,889	5,358	1,629
Energy Marketing	6,119		299
Corporate			(1,934)
Inter-segment eliminations		(1,110)	
Total	$ 141,745	$ 11,105	$ 11,816

	March 31, 2009	December 31, 2008	March 31, 2008
Total assets			
Utilities:			
Electric Utilities	$ 1,522,885	$ 1,485,040	$ 872,074
Gas Utilities	653,860	733,377	
Non-regulated Energy:			
Oil and Gas	357,233	403,583	436,716
Power Generation	121,489	155,819	148,885
Coal Mining	75,092	75,872	61,994
Energy Marketing	262,441	339,543	357,483
Corporate	88,109	186,409	57,228
Discontinued operations		246	590,687
Total	$ 3,081,109	$ 3,379,889	$ 2,525,067

(12) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and unregulated energy sector expose us to a number of risks in the normal operations 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, fuel procurement for certain of our gas-fired generation assets, and gas usage at our Gas Utilities segment;

Interest rate risk associated with variable rate credit facilities; 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. Details of derivative and hedging activities included in the accompanying Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Income are as follows:

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.

FSP FIN 39-1 permits a reporting entity to offset 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 arrangement. Each Condensed Consolidated Balance Sheet herein reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when management believes a legal right of offset exists.

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.

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 March 31, 2009		Outstanding at December 31, 2008		Outstanding at March 31, 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	273,496	31	187,368	34	187,068	33
Natural gas basis swaps sold	280,478	31	186,710	34	191,738	33
Natural gas fixed - for - float swaps purchased	101,094	21	85,412	24	53,738	24
Natural gas fixed - for - float swaps sold	107,705	21	90,171	24	67,910	24
Natural gas physical purchases	143,642	19	131,937	16	132,559	12
Natural gas physical sales	136,504	19	145,706	21	136,687	24
Natural gas options purchased			1,440	3	11,311	12
Natural gas options sold			1,440	3	11,311	12

	Outstanding at March 31, 2009		Outstanding at December 31, 2008		Outstanding at March 31, 2008	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of Bbls)						
Crude oil physical purchases	5,070	9	7,446	12	3,737	9
Crude oil physical sales	4,301	9	6,251	12	2,903	9
Crude oil swaps/options purchased	67	1	435	24	495	9
Crude oil swaps/options sold	119	4	502	24	545	9

Derivatives and certain natural gas and crude oil marketing activities were marked to fair value on March 31, 2009, December 31, 2008 and March 31, 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
March 31, 2009	$ 53,741	$ 2,317	$ 20,422	$ (534)	$ 3,673	$ 39,843
December 31, 2008	$ 52,723	$ (145)	$ 15,553	$ (777)	$ 16,315	$ 54,117
March 31, 2008	$ 45,542	$ 1,246	$ 21,393	$ 994	$ (32,876)	$ (8,475)

(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 March 31, 2009 and December 31, 2008, we had an obligation to return cash collateral of $3.7 million and $16.3 million, respectively. At March 31, 2008, we had the right to reclaim cash collateral of $32.9 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 March 31, 2009, December 31, 2008 and March 31, 2008, the market adjustments recorded in inventory were $(2.4) million, $(9.4) million and $4.6 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 March 31, 2009, December 31, 2008 and March 31, 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 are marked to fair value and are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives was reported in other comprehensive income and the ineffective portion was reported in earnings.

On March 31, 2009, December 31, 2008 and March 31, 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 Accumulated Other Comprehensive Income (Loss)	Earnings (Loss)
March 31, 2009								
Crude oil swaps/options	450,000	0.25	$ 5,189	$ 4,523	$	$ 524	$ 8,629	$ 559
Natural gas swaps	9,946,500	0.75	18,932	4,764	4	244	23,448	
			$ 24,121	$ 9,287	$ 4	$ 768	$ 32,077	$ 559
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
March 31, 2008								
Crude oil swaps/options	495,000	0.75	$ 484	$	$ 4,078	$ 2,187	$ (6,265)	$ 484

Natural gas swaps	11,657,000	1.59		66		114		12,653		3,328		(15,801)			
			$	550	$	114	$	16,731	$	5,515	$	(22,066)	$	484	

* 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.

Based on March 31, 2009 market prices, a $20.9 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.

Fuel in Storage

On March 31, 2008, we had the following swaps and related balances (in thousands):

	Notional*	Maximum Terms in Months	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Unrealized Gain
March 31, 2008								
Natural gas swaps	300,000	1	$ 245	$	$ 245	$	$	$

*gas in MMBtus

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 and option transactions to reduce our customers underlying exposure to these fluctuations. These transactions are considered derivative transactions under SFAS 133, are marked-to-market, 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 Statement 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 March 31, 2009		Outstanding at December 31, 2008	
	Notional Amounts*	Latest Expiration (months)	Notional Amounts*	Latest Expiration (months)
Natural gas futures purchased	2,110,000	24	1,290,000	3

Natural gas options purchased	3,990,000	3
Natural gas options sold	820,000	3

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*gas in MMBtus

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On March 31, 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 Included in Derivative Assets/ Liabilities
March 31, 2009	$ 1,581	$ 2	$	$ 82	$ 543	$ 2,044
December 31, 2008	$ 4,224	$	$ 2,924	$	$ 11,668	$ 8,744

Weather Derivatives

As approved in the State of Iowa, Iowa Gas uses a weather derivative to offset inherent risks, 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. The amount of realized gains included in Regulatory liabilities was $0.5 million for the three months ended March 31, 2009. The liability amount included in Current liabilities, other was $1.0 million at March 31, 2009; the receivable amount included in Current liabilities, other was $1.8 million at December 31, 2008.

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 convert the debt s variable interest rate to a fixed rate.

On March 31, 2009, December 31, 2008 and March 31, 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 Accumulated Other Comprehensive (Loss)/Income	Pre-tax Gain/(Loss)
March 31, 2009									
Interest rate swaps	$ 150,000	5.04%	7.75	$	$	$ 5,780	$ 20,340	$ (26,120)	$
Interest rate swaps	250,000	5.67%	0.75			79,677			14,763
	$ 400,000			$	$	$ 85,457	$ 20,340	$ (26,120)	$ 14,763
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)
March 31, 2008									
Interest rate swaps	$ 150,000	5.04%	8.50	$	$	$ 3,534	$ 10,007	$ (13,541)	$
Interest rate swaps	250,000	5.54%	0.25			30,621		(30,621)	
	$ 400,000			$	$	$ 34,155	$ 10,007	$ (44,162)	$

Based on March 31, 2009 market interest rates and balances, a loss of approximately $5.8 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.

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 less than \$0.1 million, \$(0.2) million and \$(0.4) million at March 31, 2009, December 31, 2008 and March 31, 2008, respectively, have been recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. The impact of foreign currency exchange transactions did not have a material effect on our Condensed Consolidated Statements of Income. All forward exchange contracts outstanding at March 31, 2009 will settle by May 25, 2009 and were as follows:

	Outstanding at March 31, 2009		Outstanding at December 31, 2008		Outstanding at March 31, 2008	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(Dollars, in thousands)						
Canadian dollars purchased	$ 20,000	2	$ 52,000	1	$ 27,000	1

(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 $1.6 million on deposit in margin accounts at March 31, 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 Sheet, 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 March 31, 2009 (in thousands):

Fair Value as of March 31, 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	$ 7,339	$ 4,717
Interest rate swaps	Derivative liabilities current		5,780
Interest rate swaps	Derivative liabilities non-current		20,340
Total derivatives designated as hedges under SFAS 133		$ 7,339	$ 30,837
Derivatives not designated as hedges under SFAS 133:			
Commodity derivatives	Derivative assets current	$ 343,372	$ 265,003
Commodity derivatives	Derivative assets non-current	19,120	7,514
Commodity derivatives	Derivative liabilities current	11,959	32,320
Commodity derivatives	Derivative liabilities non-current	170	486
Interest rate swap	Derivative liabilities current		79,677
Foreign currency derivatives	Derivative assets current	107	26
Foreign currency derivatives	Derivative liabilities current		65
Total derivatives not designated as hedges under SFAS 133		$ 374,728	$ 385,091

A description of our derivative activities is discussed in Note 12. The following tables present the impact that derivatives had on our Condensed Consolidated Statement of Income for the three months ended March 31, 2009.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged items on our accompanying Condensed Consolidated Statement of Income for the three months ended March 31, 2009 is presented as follows:

The Effect of Derivative Instruments on the Condensed Consolidated Statement of Income for the Quarter Ended March 31, 2009

Fair Value Hedges
(in thousands)

Derivatives in SFAS 133 Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$ 7,520
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	(6,955)
		$ 565

Cash Flow Hedges

The impact of cash flow hedges on our Condensed Consolidated Statement of Income for the three months ended March 31, 2009 is presented as follows:

The Effect of Derivative Instruments on the Condensed Consolidated Statement of Income and the Balance Sheet for the Quarter Ended March 31, 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	$ 2,115	Interest expense	$ (1,348)		$
Commodity derivatives	7,155	Operating revenue	6,635	Operating revenue	(927)
Total	$ 9,270		$ 5,287		$ (927)

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments that have not been designated as hedges on our Condensed Consolidated Statement of Income for the three months ended March 31, 2009 is presented below.

The Effect of Derivative Instruments on the Condensed Consolidated Statement of Income for the Quarter Ended March 31, 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	Amount of Gain/(Loss) on Derivatives Recognized in Income	
Commodity derivatives	Operating revenue	$	(8,125)
Interest rate swap	Interest rate swap		14,763
Foreign currency contracts	Operating revenue		243
		$	6,881

(14) FAIR VALUE MEASUREMENTS

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. We adopted SFAS 157 for non-financial assets and liabilities measured at fair value on a non-recurring basis effective January 1, 2009. 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.

For valuation methodologies related to instruments accounted for at fair value on a recurring basis, see Note 3 to our Notes to Consolidated Financial Statements in our 2008 Annual Report on Form 10-K

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 March 31, 2009, December 31, 2008 and March 31, 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 March 31, 2009				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[(a)]	Total
Assets:					
Commodity derivatives	$	$ 340,933	$ 24,926	$ (274,917)	$ 90,942
Foreign currency derivatives		107			107
Total	$	$ 341,040	$ 24,926	$ (274,917)	$ 91,049
Liabilities:					
Commodity derivatives	$	$ 282,420	$ 11,519	$ (273,288)	$ 20,651
Foreign currency derivatives		91			91
Interest rate swaps		105,797			105,797
Total	$	$ 388,308	$ 11,519	$ (273,288)	$ 126,539

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 March 31, 2008				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[(a)]	Total
Assets:					
Short-term investments	$	$	$ 7,290	$	$ 7,290
Commodity derivatives		89,452	12,549	(54,304)	47,697
Total	$	$ 89,452	$ 19,839	$ (54,304)	$ 54,987
Liabilities:					
Commodity derivatives	$	$ 126,127	$ 5,576	$ (87,180)	$ 44,523
Interest rate swaps		44,164			44,164
Foreign currency derivatives		355			355
Total	$	$ 170,646	$ 5,576	$ (87,180)	$ 89,042

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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 March 31, 2009, December 31, 2008 and March 31, 2008 totaled a net $(1.6) million, $(7.6) million and $32.9 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 months ended March 31, 2009 and 2008, respectively (in thousands):

	Three Months Ended March 31, 2009	
	Commodity Derivatives	
Balance as of January 1, 2009	$	16,398
Realized and unrealized losses		(245)
Purchases, issuance and settlements		(5,307)
Transfers in and/or out of level 3[(a)]		2,561
Balances as of March 31, 2009	$	13,407
Changes in unrealized losses relating to instruments still held as of March 31, 2009	$	(3,442)

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(a) Transfers into level 3 represent existing asset 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 March 31, 2008					
	Commodity Derivatives		Short-term Investments		Total	
Balance as of January 1, 2008	$	6,422	$		$	6,422
Realized and unrealized gains (losses)		1,037		(185)		852
Purchases, issuance and settlements		(486)		7,475		6,989
Balances as of March 31, 2008	$	6,973	$	7,290	$	14,263
Changes in unrealized gains (losses) relating to instruments still held as of March 31, 2008	$	(789)	$	(185)	$	(974)

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 March 31, 2008. The unrealized losses for these investments are recognized in Accumulated other comprehensive income on the accompanying Condensed Consolidated Balance Sheets.

(15) IMPAIRMENT OF LONG-LIVED ASSETS

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. 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.

(16) 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 three 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 March 31, 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 have notified the staff of FERC of our findings. We have 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.

Long-Term Power Sales Agreement

In March 2009, our 10-year power sales contract with MEAN 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-capacity from Wygen III and Neil Simpson II plants are as follows:

20 MW	10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
15 MW	10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
12 MW	6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
10 MW	5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II

(17) 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 three months ended March 31, 2009 included working capital adjustments, which resulted in a cash receipt of $7.9 million, settlement of pension liabilities, which resulted in a cash payment of $4.3 million, and adjustments to deferred income taxes. Outstanding adjustments relate to employee benefits, which we expect to finalize in the second quarter of 2009. The estimated purchase price allocations are subject to adjustment, generally within one year of the date of acquisition. Allocation of the purchase price is as follows (in thousands):

Current assets	$	113,547
Property, plant and equipment		542,094
Derivative assets		4,695
Goodwill		344,263
Intangible assets		4,884
Deferred assets		70,939
	$	1,080,422
Current liabilities	$	95,349
Deferred credits and other liabilities		54,550
	$	149,899
Net assets	$	930,523

After finalization of the working capital adjustment, the allocation of the purchase price resulted in $344.3 million of goodwill and $4.9 million of intangible assets. Goodwill of $246.3 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 March 31, 2008
Operating revenues	$ 488,650
Income from continuing operations	31,446
Net income available for common stock	36,421
Earnings per share	
Basic:	
Continuing operations	$ 0.83
Total	$ 0.96
Diluted:	
Continuing operations	$ 0.82
Total	$ 0.95

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.

(18) INCOME TAXES

Our effective tax rate for the first quarter of 2009 was lower than previous periods as a result of a positive adjustment to 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.

(19) GOODWILL

The majority of our goodwill relates to the Aquila assets, which were acquired on July 14, 2008. In accordance with SFAS 142 and a decline in our market capitalization, we tested goodwill for impairment as of March 31, 2009. We estimated the fair value of the goodwill using discounted cash flow and comparable transaction methodologies. This analysis required the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, discount rates, and long-term earnings and valuation multiples. As a result of the analysis and given our belief that these assets will provide relatively stable, long-term cash flows with growth potential, we did not record an impairment charge for the goodwill.

(20) 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.

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Operating revenues	$	$ 26,361
Pre-tax income from discontinued operations	1,190	7,904
Income tax expense	424	3,071
Net income from discontinued operations	$ 766	$ 4,833

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 was $3.5 million after-tax for the three months ended March 31, 2008. These allocated costs remain in the Power Generation segment.

Interest expenses included within the operations of the discontinued entities was recorded pursuant to EITF 87-24 and includes 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 months ended March 31, 2008, interest expense allocated to discontinued operations was $2.7 million.

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

		March 31, 2008
Current assets	$	30,177
Property, plant and equipment, net of accumulated depreciation		497,895
Goodwill		26,501
Intangible assets (net of accumulated amortization of $28,865)		20,272
Other non-current assets		14,736
Current liabilities		(31,357)
Long-tem debt		(57,857)
Other non-current liabilities		(30)
Net assets	$	500,337

(21) SUBSEQUENT EVENTS

Sale to MDU

On April 9, 2009, Black Hills Power sold a 25% ownership interest in its Wygen III generation facility to MDU. 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 $30.2 million were 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.

Guarantee

Effective May 1, 2009, we issued a guarantee for up to $37.9 million to GE for payment obligations arising from a change order to a purchase contract for a LMS100 natural gas turbine generator, which is expected to be used in meeting the needs of our Colorado Electric customers. It is a continuing guarantee which terminates upon payment in full of the purchase price to GE. Payments are scheduled based upon estimated milestone dates, with the final payment due October 27, 2010.

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 are co-lead arranger banks. This facility replaces its previously uncommitted $300 million credit facility which expires on May 8, 2009. Enserco expects to close an additional $60 million of funding in May 2009 with new facility lenders, raising the total committed facility to $300 million.

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 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 portion of this Item 2, beginning on Page 65.

Significant Events

Wygen III Power Plant Project

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%. MDU reimbursed us for 25% of the costs incurred to date on the ongoing construction of the facility. We received $30.2 million, which 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.

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 renegotiated 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 with MEAN 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 from Wygen III and Neil Simpson II plants are as follows:

20 MW	10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
15 MW	10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
12 MW	6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
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 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 Xcel Energy which expires on December 31, 2011. The initial decision of the CPUC waives the competitive bidding process for the two turbines; the remaining three turbines will be completed through a competitive bid process.

Results of Operations

Executive Summary

Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2008.

Income from continuing operations for the three month period ended March 31, 2009 was $25.6 million, or $0.66 per share, compared to $11.8 million, or $0.31 per share, reported for the same period in 2008. For the three month period ended March 31, 2009, net income available for common stock was $26.4 million or $0.68 per share, compared to $16.8 million, or $0.44 per share, for the same period in 2008.

Included in the 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;

$9.6 million after-tax non-cash gain, resulting from an unrealized net mark-to-market gain for certain interest rate swaps entered into in 2007;

Non-cash ceiling test impairment 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 quarter; and

Lower effective tax rate for the quarter relating to a $3.8 million benefit associated with an improvement of a previously recorded tax position.

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 and higher interest expense.

Earnings from the Oil and Gas segment decreased for the quarter due to a decrease in operating revenues due to lower prices and a ceiling test impairment, partially offset by a 4% increase in production compared to the first quarter 2008. Average oil prices received, net of hedges, decreased 37% and average gas prices received, net of hedges, decreased 34%.

Increased earnings from the Power Generation segment 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, partially offset by increased interest expense. In addition, for the three months ended March 31, 2008, results included $5.4 million of allocated indirect corporate costs and intersegment net interest expense not classified to discontinued operations for the IPP Transaction.

Lower earnings from the Coal Mining segment resulted from 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 crude oil margins received and lower unrealized mark-to-market losses partially offset by lower realized natural gas margins. Realized natural gas margins were impacted by changes in market conditions as lower geographic and calendar spreads compared to 2008 contributed to the earnings decline. As part of our efforts to preserve our liquidity, we have intentionally limited the usage of Enserco s uncommitted credit facility. This has had a negative impact on marketing results.

Income from discontinued operations was $0.8 million, or $0.02 per share, for the three month period ended March 31, 2009, compared to $5.1 million, or $0.13 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

Revenues and Income (Loss) from Continuing Operations provided by each business group were as follows (in thousands):

	Three Months Ended March 31, 2009	2008
Revenues		
Utilities	$ 393,397	$ 99,302
Non-regulated Energy	44,546	53,548
	$ 437,943	$ 152,850
Income (loss) from continuing operations		
Utilities	$ 26,582	$ 10,167
Non-regulated Energy	(6,493)	3,583
Corporate	5,536	(1,934)
	$ 25,625	$ 11,816

Income from continuing operations increased $13.8 million for the three months ended March 31, 2009 due primarily to the following:

$17.3 million income from the Gas Utilities segment;

An $18.0 million increase in Power Generation earnings;

A $0.7 million increase in Energy Marketing earnings; and

A $7.5 million increase in corporate income.

The increases in earnings were partially offset by:

A $0.9 million decrease in Electric Utilities earnings;

A $28.3 million decrease in Oil and Gas earnings; and

A $0.8 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.

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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.

Utilities Group

In July 2008, we acquired from Aquila regulated electric utility assets in Colorado and four 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 March 31, 2009	2008
	(in thousands)	
Revenue electric	$ 122,177	$ 82,574
Revenue gas	15,098	17,034
Total revenue	137,275	99,608
Fuel and purchased power electric	64,896	40,256
Purchased gas	10,258	11,858
Total fuel and purchased power	75,154	52,114
Gross margin electric	57,281	42,318
Gross margin gas	4,840	5,176
Total gross margin	62,121	47,494
Operating expenses	42,875	27,628
Operating income	$ 19,246	$ 19,866
Income from continuing operations and net income available for common stock	$ 9,317	$ 10,167

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 quarter are the operations of Colorado Electric, acquired July 14, 2008 as part of the Aquila Transaction:

Sales Revenues	Three Months Ended March 31, 2009 (in thousands)	2008
Residential:		
Black Hills Power	$ 14,281	$ 12,966
Cheyenne Light	7,487	9,950
Colorado Electric	16,503	
Total Residential	38,271	22,916
Commercial:		
Black Hills Power	14,643	13,484
Cheyenne Light	12,061	11,421
Colorado Electric	13,228	
Total Commercial	39,932	24,905
Industrial:		
Black Hills Power	4,750	5,296
Cheyenne Light	2,533	1,988
Colorado Electric	8,092	
Total Industrial	15,375	7,284
Municipal:		
Black Hills Power	636	625
Cheyenne Light	241	232
Colorado Electric	1,029	
Total Municipal	1,906	857
Contract Wholesale:		
Black Hills Power	6,553	6,931
Off-system Wholesale:		
Black Hills Power	9,220	15,097
Cheyenne Light	1,980	1,260
Colorado Electric	4,053	
Total Off-system Wholesale	15,253	16,357
Other:		
Black Hills Power	4,375	3,233
Cheyenne Light	101	91
Colorado Electric	411	
Total Other	4,887	3,324
Total Sales Revenues	$ 122,177	$ 82,574

Quantities Generated and Purchased	Three Months Ended March 31, 2009	2008
	(in MWh)	
Generated		
Coal-fired:		
Black Hills Power	437,551	432,882
Cheyenne Light	191,556	188,013
Colorado Electric	66,475	
Total Coal	695,582	620,895
Gas and Oil-fired:		
Black Hills Power	1,075	37,000
Cheyenne Light		
Colorado Electric		
Total Gas and Oil	1,075	37,000
Total Generated:		
Black Hills Power	438,626	469,882
Cheyenne Light	191,556	188,013
Colorado Electric	66,475	
Total Generated	696,657	657,895
Purchased:		
Black Hills Power	432,839	384,581
Cheyenne Light	157,987	138,631
Colorado Electric	487,526	
Total Purchased	1,078,352	523,212
Total Generated and Purchased	1,775,009	1,181,107

Quantity Sold	Three Months Ended March 31, 2009	2008
	(in MWh)	
Residential:		
Black Hills Power	163,476	163,034
Cheyenne Light	71,126	75,342
Colorado Electric	142,673	
Total Residential	377,275	238,376
Commercial:		
Black Hills Power	175,256	173,459
Cheyenne Light	145,545	145,317
Colorado Electric	149,466	
Total Commercial	470,267	318,776
Industrial:		
Black Hills Power	85,984	102,669
Cheyenne Light	42,822	33,747
Colorado Electric	121,814	
Total Industrial	250,620	136,416
Municipal:		
Black Hills Power	8,095	8,208
Cheyenne Light	1,025	1,020
Colorado Electric	7,420	
Total Municipal	16,540	9,228
Contract Wholesale:		
Black Hills Power	168,679	171,620
Off-system Wholesale:		
Black Hills Power	243,786	227,741
Cheyenne Light	70,104	64,972
Colorado Electric	105,943	
Total Off-system Wholesale	419,833	292,713
Total Quantity Sold	1,703,214	1,167,129
Losses and Company Use:		
Black Hills Power	26,190	7,733
Cheyenne Light	18,921	6,245
Colorado Electric	26,684	
Total Losses and Company Use	71,795	13,978
Total Energy	1,775,009	1,181,107

Degree Days	Three Months Ended March 31, 2009		2008	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Actual				
Black Hills Power	3,254	(1)%	3,361	2%
Cheyenne Light	2,824	(10)%	3,236	3%
Colorado Electric	2,370	(10)%		

Electric Utilities Power Plant Availability

	Three Months Ended March 31, 2009	2008
Coal-fired plants	97.3%	94.1%
Other plants	99.2%	94.9%
Total availability	98.0%	94.4%

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 March 31, 2009	2008
Sales Revenues (in thousands):		
Residential	$ 9,012	$ 10,009
Commercial	4,429	5,028
Industrial	1,434	1,788
Other	223	209
Total Sales Revenues	$ 15,098	$ 17,034
Sales Margins (in thousands):		
Residential	$ 1,171	$ 1,278
Commercial	3,277	3,509
Industrial	169	180
Other	223	209
Total Sales Margins	$ 4,840	$ 5,176
Volumes Sold (Dth):		
Residential	1,015,246	1,208,093
Commercial	584,423	686,272
Industrial	247,325	261,955
Total Volumes Sold	1,846,994	2,156,320

Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2008. Income from continuing operations for the Electric Utilities decreased $0.9 million from the prior period primarily due to the following:

A $1.0 million decrease in margins from off-system sales reflecting the lower margins available in the industry s current low energy price environment; and

A $3.3 million increase in interest expense due to additional debt associated with the acquisition of Colorado Electric.

Partially offsetting the increases were the following:

Increased gross margins of $1.6 million primarily due to transmission rate increases effective January 1, 2009 at Black Hills Power; and

Increased AFUDC of $1.5 million due to construction of the Wygen III plant in 2009.

Gas Utilities

Operating results for the Gas Utilities are as follows:

	Three Months Ended March 31, 2009 (in thousands)
Revenue:	
Natural gas regulated	$ 248,981
Other non-regulated services	7,356
Total sales	256,337
Cost of sales:	
Natural gas regulated	181,215
Other non-regulated services	4,570
Total cost of sales	185,785
Gross margin	70,552
Operating expenses	41,177
Operating income	$ 29,375
Income from continuing operations and net income available for common stock	$ 17,265

The following tables summarize regulated Gas Utilities sales revenues, sales margins and volumes for the three months ended March 31, 2009:

	Sales Revenues (in thousands)	Sales Margins (in thousands)	Volumes Sold (Dth)
Residential:			
Colorado	$ 27,410	$ 5,115	2,351,614
Nebraska	59,282	15,135	5,699,778
Iowa	54,545	15,565	5,465,557
Kansas	30,705	9,056	2,946,898
Total Residential	171,942	44,871	16,463,847
Commercial:			
Colorado	5,832	967	509,478
Nebraska	21,959	4,744	2,335,660
Iowa	25,487	5,122	2,822,937
Kansas	10,416	2,219	1,120,927
Total Commercial	63,694	13,052	6,789,002
Industrial:			
Colorado	130	35	12,257
Nebraska	1,513	142	202,481
Iowa	617	66	82,132
Kansas	1,260	214	189,254
Total Industrial	3,520	457	486,124
Transportation:			
Colorado	176	176	234,974
Nebraska	3,952	3,952	7,583,683
Iowa	1,100	1,100	4,067,274
Kansas	1,606	1,606	3,492,627
Total Transportation	6,834	6,834	15,378,558
Other:			
Colorado	29	29	
Nebraska	648	648	890
Iowa	426	426	36,173
Kansas	1,888	1,449	59,582
Total Other	2,991	2,552	96,645
Total Regulated	248,981	67,766	39,214,176
Non-regulated Services	7,356	2,786	
Total	$ 256,337	$ 70,552	39,214,176

Degree Days	2009	
Heating Degree Days:	Actual	Variance From Normal
Colorado	2,524	(12)%
Nebraska	2,979	(6)%
Iowa	3,439	(1)%
Kansas	2,202	(14)%
Combined Gas Utilities Heating Degree Day	3,013	(6)%

Results from the Gas Utilities for the three month period ended March 31, 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 quarter ended March 31, 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 on the state, the winter heating season begins around November 1 and ends around March 31. Margins for the Gas Utilities for the quarter ended March 31, 2009 increased 27% over the quarter ended December 31, 2008. This increase was driven by a 33% increase 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	Pending	$ 13.6	Pending
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

(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) Iowa Gas and the OCA reached a settlement agreement that resolved all issues in the rate case. This agreement was filed with the IUB in March 2009 and is subject to their approval. The settlement agreement provides for no refund of interim rates collected, a final rate increase of $10.4 million plus actual rate case expenses, and the implementation of a three-year pilot program for recovery of carrying charges on integrity capital expenditures up to $6.0 million per year. It is anticipated that the IUB will issue an order by July 2, 2009.

(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 49.52% debt and 50.48% equity.

(4) On February 10, 2009, the FERC approved a revision 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.

Non-regulated Energy Group

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

Oil and Gas

	Three Months Ended March 31, 2009 (in thousands)		2008	
Revenue	$	16,511	$	26,122
Operating expenses*		62,262		20,489
Operating income	$	(45,751)	$	5,633
Income (loss) from continuing operations and net income available for common stock	$	(25,720)	$	2,551

*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 March 31, 2009	2008
Fuel production:		
Bbls of oil sold	99,370	99,975
Mcf of natural gas sold	2,688,890	2,563,190
Mcf equivalent sales	3,285,110	3,163,040

	Three Months Ended March 31, 2009		2008	
Average price received: [a]				
Gas/Mcf [b] [c]	$	4.91	$	7.46
Oil/Bbl	$	50.42	$	79.50
Depletion expense/Mcfe	$	2.49	$	2.33

(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 for March 31, 2009 and 2008, respectively, resulting in a $0.48/Mcf and $0.88/Mcf price impact

The following are summaries of LOE/Mcfe:

	Three Months Ended March 31, 2009			Three Months Ended March 31, 2008		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$ 1.22	$ 0.26	$ 1.48	$ 1.54	$ 0.44	$ 1.98
Colorado	0.74	0.46	1.20	1.22	0.84	2.06
Wyoming	1.42		1.42	1.81		1.81
All other properties	0.97	0.41	1.38	1.32	(0.02)	1.30
All locations	$ 1.17	$ 0.24	$ 1.41	$ 1.52	$ 0.25	$ 1.77

Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2008. Income from continuing operations decreased $28.3 million for the three months ended March 31, 2009 compared to the same period in 2008 primarily due to:

A $27.8 million after-tax non-cash ceiling test impairment charge due to a write-down in value of our natural gas and crude oil properties resulting from low quarter-end prices for the commodities. The write-down of gas and oil properties was based on 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 $9.6 million, despite a 4% increase in production, due to a 37% decrease in the average hedged price of oil received and a 34% decrease in average hedged price of gas received; and

Increased depletion expense of $0.8 million primarily due to higher depletion rates.

Partially offsetting these were the following:

A $1.0 million decrease in LOE as compared to 2008, which had some severe weather impacts;

A $1.7 million decrease in production taxes due to lower oil and natural gas prices; and

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

Coal Mining

	Three Months Ended March 31, 2009 (in thousands)	2008
Revenue	$ 14,402	$ 13,247
Operating expenses	14,182	11,617
Operating income	$ 220	$ 1,630
Income from continuing operations and net income available for common stock	$ 819	$ 1,629

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

	Three Months Ended March 31, 2009 (in thousands)	2008
Tons of coal sold	1,506	1,545
Cubic yards of overburden moved	3,162	3,030

Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2008.

Income from continuing operations from our Coal Mining segment for the three months ended March 31, 2009 decreased $0.8 million compared to the same period in the prior year. Results were impacted by the following:

Operating expenses increased $2.6 million, or 22%, during the three months ended March 31, 2009 primarily due to increased depreciation expense due to increased equipment usage and an increased asset base and increased coal taxes due to higher coal prices. Cubic yards of overburden moved increased 4%.

Partially offsetting the increased expenses were the following:

Revenue increased $1.2 million, or 9%, for the three month period ended March 31, 2009 compared to the same period in 2008 due to an increase in average price received. The higher average price received includes the impact of regulated sales prices determined in part by a return on depreciable asset component; and

Lower diesel fuel costs.

Energy Marketing

	Three Months Ended March 31, 2009		2008	
	(in thousands)			
Revenue				
Realized gas marketing gross margin	$	10,971	$	13,423
Unrealized gas marketing gross margin		(1,336)		(6,785)
Realized oil marketing gross margin		2,977		1,573
Unrealized oil marketing gross margin		(5,792)		(2,092)
		6,820		6,119
Operating expenses		5,263		5,937
Operating income	$	1,557	$	182
Income from continuing operations and net income available for common stock	$	1,037	$	299

The following is a summary of average daily volumes marketed:

		Three Months Ended March 31, 2009	2008
Natural gas physical sales	MMBtus	2,252,800	1,794,090
Crude oil physical sales	Bbls	11,060	7,080

Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2008. Income from continuing operations increased $0.7 million for the three months ended March 31, 2009 compared to the same period in 2008, primarily due to:

A $1.7 million increase in unrealized marketing margins; and

Lower operating expenses primarily due to lower bank fees from decreased use of lines of credit.

Partially offsetting these increases were the following:

A $1.0 million decrease in realized marketing margins primarily due to prevailing conditions in natural gas markets affecting both transportation and storage strategies. In addition, gross margins from crude oil were lower due to the impact of decreasing commodity prices on inventory held to meet pipeline requirements. As part of our efforts to preserve liquidity, we have intentionally limited usage of the uncommitted credit facility. This has had a negative impact on marketing results.

Power Generation

	Three Months Ended March 31, 2009 (in thousands)	2008
Revenue	$ 7,619	$ 8,864
Operating gains (expenses)	22,125	(7,248)
Operating income	$ 29,744	$ 1,616
Income (loss) from continuing operations	$ 17,153	$ (896)

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

	Three Months Ended March 31, 2009	2008
Contracted power plant fleet availability:		
Coal-fired plant	95.5%	96.9%
Other plants	98.0%	99.9%
Total availability	96.6%	98.0%

Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2008. Income from continuing operations increased $18.0 million for the three months ended March 31, 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.

Partially offsetting were the following:

Allocated indirect corporate costs and inter-segment interest expense related to the IPP assets sold and not reclassified to discontinued operations, of $5.4 million for the three months ended March 31, 2008; and

A $3.6 million increase in interest expense primarily due to a change in inter-segment debt to equity capital structure.

Corporate

Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2008. Income increased $7.5 million primarily due to unrealized net, mark-to-market gains at March 31, 2009 of approximately $9.6 million after-tax on certain interest rate swaps and a decrease in transition and integration costs for the Aquila Transaction to $0.7 million in the first three months of 2009 compared to $1.4 million in 2008, partially offset by a $2.9 million after-tax increase in interest expense.

Discontinued Operations

Earnings from discontinued operations were $0.8 million for the three month period ended March 31, 2009, compared to $5.1 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 three month period ended March 31, 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. We plan to fund future property and investment additions including the construction costs of the 110 MW Wygen III generation facility located near Gillette, Wyoming and generation for Colorado Electric from internally generated cash resources and external financings.

Cash flows from operations of $200.3 million for the three month period ended March 31, 2009 represent a $146.7 million increase compared to the same period in the prior year. The cash provided by operating activities for the current period was due to an increase of $13.8 million in our income from continuing operations and changes in working capital as follows:

A $114.6 million increase in cash flows from working capital changes. This increase primarily resulted from a $43.4 million increase in cash flows from decreased net purchases of materials, supplies and fuel and a $146.4 million increase from accounts receivable and other current assets partially offset by a $75.3 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 $14.3 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 $13.9 million increase in depreciation, depletion and amortization;

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; and

A $14.8 million non-cash effect of unrealized mark-to-market gains on interest rate swaps.

During the three months ended March 31, 2009, we had cash outflows from investing activities of

$11.4 million, which were primarily due to the following:

Cash outflows of $71.3 million for property, plant and equipment additions. These outflows include approximately $25.5 million related to the construction of our Wygen III power plant, approximately $9.5 million in oil and gas property maintenance capital and development drilling, and approximately $20.0 million of distribution, transmission and generation at our Electric Utilities, which includes new transmission at Colorado Electric and an 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; and

Cash inflows of $7.9 million for working capital adjustments on the purchase price allocation of the Aquila Transaction.

During the three months ended March 31, 2009, we had net cash outflows from financing activities of $235.9 million primarily due to:

$224.0 million net are payments on the revolving credit facility; and

$13.8 million payment of cash dividends on common stock.

Dividends

Dividends paid on our common stock totaled $13.8 million during the three months ended March 31, 2009, or $0.355 per share. On April 28, 2009, our Board of Directors declared a quarterly dividend of $0.355 per share payable June 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 March 31, 2009, we had approximately $121.6 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 1.2% one-month borrowing rate as of March 31, 2009).

Our revolving credit facility can be used to fund our working capital needs and for general corporate purposes. At March 31, 2009, we had borrowings of $97.0 million and $56.7 million of letters of credit issued on our revolving credit facility. Available capacity remaining on our revolving credit facility was approximately $371.3 million at March 31, 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 acquisition 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 (non 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 $1.1 billion at March 31, 2009, which was approximately $274.3 million in excess of the net worth we were required to maintain under the credit facility. At March 31, 2009, our long-term debt ratio was 30.5%, our total debt leverage ratio (long-term debt and short-term debt) was 47.8%, and our recourse leverage ratio was approximately 52.2%. Our interest expense coverage ratio for the twelve month period ended March 31, 2009 was 4.3 to 1.0.

Enserco Credit Facility

Our Energy Marketing segment, Enserco, had a $300 million uncommitted, discretionary line of credit to provide support for the purchase, sale, transportation and storage of natural gas and crude oil. The line of credit, which was secured by this segment s assets, expired on May 8, 2009. The Enserco Credit Facility allowed for the issuance of letters of credit and loans for our marketing operations. At March 31, 2009, there were outstanding letters of credit issued under the facility of $95.1 million, with no borrowing balances outstanding on the 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 are co-lead arranger banks. This facility replaces its previously uncommitted $300 million credit facility which expires on May 8, 2009. Enserco expects to close an additional $60 million of funding in May 2009 with new facility lenders, raising the total committed facility to $300 million.

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 and following our July 2008 borrowing we have no additional borrowing capacity available under the facility.

Borrowings under the term loan are available under a base rate option, which is based on the then-current prime rate, or under a LIBOR option, which is based on the then-current LIBOR plus an applicable margin. The loan matures on December 29, 2009 and has the following interest rate:

The applicable margin for base-rate borrowings is (i) 200 basis points for the period commencing December 18, 2008 through March 31, 2009, (ii) 250 basis points for the period commencing April 1, 2009 through June 30, 2009, (iii) 300 basis points for the period commencing July 1, 2009 through September 30, 2009, and (iv) 350 basis points thereafter. If our credit ratings, as assigned by S&P and Moody s, fall below investment grade, the applicable margin will increase by an additional 25 basis points; and

The applicable margin for LIBOR borrowings is (i) 300 basis points for the period commencing December 18, 2008 through March 31, 2009, (ii) 350 basis points for the period commencing April 1, 2009 through June 30, 2009, (iii) 400 basis points for the period commencing July 1, 2009 through September 30, 2009, and (iv) 450 basis points thereafter. If our credit ratings, as assigned by S&P and Moody s, fall below investment grade, the applicable margin will increase by 25 basis points.

As of March 31, 2009, the facility has a borrowing spread of 300 basis points over LIBOR (which equates to a 3.5% one-month borrowing rate as of March 31, 2009).

The Acquisition Facility also includes certain affirmative and negative covenants and events of default that largely replicate the covenants in our corporate revolving credit facility. We were in compliance with all such covenants as of March 31, 2009.

On April 9, 2009, we received proceeds of $30.2 million for the sale of 23.5% of the Wygen III plant to MDU. These proceeds were used to pay down a portion of the Acquisition 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 long-term debt issuances, some of which may be completed in the second quarter of 2009, to replace the Acquisition Credit Facility, refinance other short-term debt, and fund our power generation construction projects.

In the unexpected 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 statement. During the first quarter of 2009, we recorded a $14.8 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 $79.7 million at March 31, 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 $0.4 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 8 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.

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.

Capital Requirements

During the three months ended March 31, 2009, capital expenditures were approximately $100.2 million for property, plant and equipment additions, which were partially financed through approximately $28.9 million of accrued liabilities. We currently expect total capital expenditures in 2009 to approximate $313.5 million. This sum includes, but is not limited to: $62.1 million for our share of the 110 MW 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.

Forecasted capital requirements for maintenance capital and development capital are as follows:

	Three Months Ended March 31, 2009 Expenditures (in thousands)	Total 2009 Planned Expenditures
Utilities:		
Electric Utilities Wygen III (1)	$ 25,539	$ 62,100
Electric Utilities (2) (3)	20,041	135,268
Gas Utilities	10,501	42,508
Non-regulated Energy:		
Oil and Gas(4)	9,501	38,621
Power Generation	1,396	4,925
Coal Mining	4,294	12,592
Energy Marketing		4,135
Corporate		13,342
	$ 71,272	$ 313,491

(1) 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 do not 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 are currently evaluating the total costs of building these new facilities and expect to spend capital 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 make many of our development drilling sites uneconomical, which 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 $8.6 million from $93.5 million at December 31, 2008 to $102.1 million at March 31, 2009. Approximately $67.0 million of the firm transportation and storage fee obligations relate to the 2009-2011 period with the remaining occurring thereafter.

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. Forward-looking information involves risks and uncertainties, and certain important factors can cause actual results to differ materially from those anticipated. The forward-looking statements contained in this report include:

We expect to refinance in the bank loan markets or the debt capital markets the acquisition debt we incurred in the Aquila Transaction before the acquisition loan matures in the fourth quarter of 2009. 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 finance our acquisition debt 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 permanently finance the acquisition debt 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.

In connection with the IPP Transaction, we deferred tax payments of $185 million. Some important factors that could cause actual results to differ materially from those anticipated include:

§ The Internal Revenue Service could successfully challenge our deferred tax planning strategies, which could impair our ability to defer all or part of these tax payments.

We expect to make contributions to our defined benefit pension plans of approximately $14.4 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 $313.5 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.

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):

	March 31, 2009	December 31, 2008
Net derivative liabilities	$ (543)	$ (7,444)
Cash collateral	2,044	8,744
	$ 1,501	$ 1,300

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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 three months ended March 31, 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		(11,531)
Unrealized loss on new positions entered during the period and still existing at March 31, 2009		(4,680)
Realized loss on positions that existed at December 31, 2008 and were settled during the period		(1,944)
Change in cash collateral		12,642
Unrealized gain on positions that existed at December 31, 2008 and still exist at March 31, 2009		10,837
Total fair value of energy marketing positions at March 31, 2009	$	33,771 [(a)]

(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):

	March 31, 2009	December 31, 2008
Net derivative assets (liabilities)	$ 39,843	$ 54,117
Cash collateral	(3,673)	(16,315)
Market adjustment recorded in material, supplies and fuel	(2,399)	(9,355)
	$ 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 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	$ (3,673)	$	$ (3,673)
Level 2	28,525	2,369	30,894
Level 3	8,749	200	8,949
Market value adjustment for inventory (see footnote (a) above)	(2,399)		(2,399)
Total fair value of our energy marketing positions	$ 31,202	$ 2,569	$ 33,771

The following table presents a reconciliation of our March 31, 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)	$ 33,771
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	5,026
Fair value of all forward positions (non-GAAP)	38,797
Cash collateral included in GAAP marked-to-market fair value	3,673
Fair value of all forward positions excluding cash collateral (non-GAAP)	$ 42,470

There have been no material changes in market risk faced by us from 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	04/25/2007	Swap	04/09	06/09	2,500	$ 7.21
San Juan El Paso	04/26/2007	Swap	04/09	06/09	2,500	$ 7.15
San Juan El Paso	05/09/2007	Swap	04/09	06/09	5,000	$ 7.24
CIG	05/09/2007	Swap	04/09	06/09	2,000	$ 6.87
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

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Crude Oil

Location	Transaction Date	Hedge Type	Term		Volume (Bbls/month)	Price	
NYMEX	04/26/2007	Swap	04/09	06/09	5,000	$	70.25
NYMEX	05/10/2007	Swap	04/09	06/09	5,000	$	69.10
NYMEX	05/29/2007	Put	04/09	06/09	5,000	$	65.00
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	09/12/2007	Put	04/09	06/09	5,000	$	70.00
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

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 March 31, 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 March 31, 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 March 31, 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 40% of our consolidated assets at March 31, 2009, 68% of our consolidated revenues and 56% of our net income for the quarter ended March 31, 2009. Our disclosure controls and procedures were not materially impacted by the acquisition.

BLACK HILLS CORPORATION

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 16 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 16 is incorporated by reference into this item.

Item 1A. Risk Factors

There have been no material changes in risk factors involving us from those previously disclosed in Item 1A. of Part I in our Annual Report on Form 10-K for the year ended December 31, 2008.

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
January 1, 2009 January 31, 2009	9,388 (1)	$ 27.29		
February 1, 2009 February 28, 2009	1,063	$ 26.61		
March 1, 2009 March 31, 2009	2,293	$ 16.55		
Total	12,744	$ 25.30		

(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 5. Other Information

Entry into a Material Definitive Agreement

On May 8, 2009, the Registrant s subsidiary, Enserco Energy Inc. (Enserco), entered into a Third Amended and Restated Credit Agreement effective as of May 8, 2009, by and among Enserco Energy Inc., as borrower, Fortis Capital Corp., as administrative agent and collateral agent; Societe Generale as Syndication Agent, BNP Paribas as Documentation Agent, U.S. Bank National Association, The Bank of Tokyo Mitsubishi UFJ, Ltd., New York Branch and the other financial institutions which may become parties hereto.

The Third Amended and Restated Credit Agreement provides for a $300 million committed stand-alone credit facility to replace Enserco s previously uncommitted $300 million credit facility, which was due to expire May 9, 2009. Enserco has received commitments on $240 million under the facility and has the right to receive commitments up to the $300 million maximum line. The facility is secured by all of Enserco s assets and provides support for the purchase and sale of natural gas and crude oil.

Item 6. Exhibits

Exhibit 3	Amended and Restated Bylaws of Black Hills Corporation dated January 30, 2009 (filed as Exhibit 3 to the Company s 8-K filed on February 3, 2009 and incorporated by reference herein).
Exhibit 10	Third Amended and Restated Credit Agreement effective May 8, 2009 among Enserco Energy Inc., as borrower, Fortis Capital Corp., as administrative agent and collateral agent; Societe Generale as Syndication Agent, BNP Paribas as Documentation Agent, U.S. Bank National Association, The Bank of Tokyo Mitsubishi UFJ, Ltd., New York Branch and the other financial institutions which may become parties hereto.
Exhibit 12	Statements Regarding Computation of Ratio of Earnings to Fixed Charges.
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.
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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.

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: May 8, 2009

EXHIBIT INDEX

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