

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

**Form 10-Q**

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2008.

OR

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  No

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  Accelerated filer

Non-accelerated filer  Smaller reporting company

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

Yes  No

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, 2008
Common stock, \$1.00 par value	38,405,402 shares

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## GLOSSARY OF TERMS

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

AFUDC	Allowance for Funds Used During Construction
ARB	Accounting Research Bulletin
ARB 51	ARB 51 “Consolidated Financial Statements”
Aquila	Aquila, Inc.
Bbl	Barrel
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
BHER	Black Hills Energy Resources, Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
Black Hills Energy	Black Hills Energy, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Btu	British thermal unit
CFIUS	Committee on Foreign Investment in the United States
Cheyenne Light	Cheyenne Light, Fuel & Power Company, a direct, wholly-owned subsidiary of the Company
Cheyenne Light Pension Plan	The Cheyenne Light, Fuel & Power Company Pension Plan
Dth	Dekatherm
Enserco	Enserco Energy Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
FASB	Financial Accounting Standards Board
FSP	FASB Staff Position
FSP FAS 157-1	Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements that Address Fair Value Measurement for Purposes of Lease Classification or Measurement under Statement 13
FSP FAS 157-2	Effective Date of FASB Statement No. 157
FSP FIN 39-1	Amendment of FASB Interpretation No. 39
FERC	Federal Energy Regulatory Commission
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”
GAAP	Generally Accepted Accounting Principles
Great Plains	Great Plains Energy Incorporated
Hastings	Hastings Funds Management Ltd
IIF	IIF BH Investment LLC, a subsidiary of an investment entity advised by JPMorgan Asset Management
Indeck	Indeck Capital, Inc.
IPP	Independent Power Production
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Las Vegas I	Las Vegas I gas-fired power plant
LVC	Las Vegas Cogeneration Limited Partnership, an indirect, wholly-owned subsidiary of Black Hills Energy, Inc.
Mcf	Thousand cubic feet
Mcfe	One thousand cubic feet equivalent
MMBtu	One million British thermal units
Moody’s	Moody’s Investor Services, Inc.
MW	Megawatt

MWh	Megawatt-hour
Nevada Power	Nevada Power Company
PNM	PNM Resources, Inc.
PUCN	Public Utilities Commission of Nevada
SEC	U. S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS 13	SFAS 13, “Accounting for Leases”
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 144	SFAS 144, “Accounting for the Impairment of Long-lived Assets”
SFAS 157	SFAS 157, “Fair Value Measurements”
SFAS 159	SFAS 159, “The Fair Value Option for Financial Assets and Financial Liabilities”
SFAS 160	SFAS 160, “Non-controlling Interest in Consolidated Financial Statements – an amendment of ARB 51”
SFAS 161	SFAS 161, Disclosure about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133
S&P	Standard & Poor’s Rating Services
Valencia	Valencia Power, LLC, an indirect, wholly-owned subsidiary of Black Hills Energy, Inc.
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.

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

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
	(in thousands, except per share amounts)	
Operating revenues	\$ 179,211	\$ 186,533
Operating expenses:		
Fuel and purchased power	54,615	51,289
Operations and maintenance	26,203	20,559
Administrative and general	25,549	25,663
Depreciation, depletion and amortization	25,644	23,168
Taxes, other than income taxes	10,636	9,899
	<u>142,647</u>	<u>130,578</u>
Operating income	<u>36,564</u>	<u>55,955</u>
Other income (expense):		
Interest expense	(12,333)	(11,109)
Interest income	433	733
Allowance for funds used during construction – equity	281	1,834
Other income, net	344	349
	<u>(11,275)</u>	<u>(8,193)</u>
Income from continuing operations before equity in earnings of unconsolidated subsidiaries, minority interest and income taxes	25,289	47,762
Equity in earnings of unconsolidated subsidiaries	232	845
Minority interest	(77)	(94)
Income tax expense	<u>(8,872)</u>	<u>(16,013)</u>
Income from continuing operations	16,572	32,500
Income (loss) from discontinued operations, net of taxes	219	(47)
Net income	<u>\$ 16,791</u>	<u>\$ 32,453</u>
Weighted average common shares outstanding:		
Basic	<u>37,826</u>	<u>35,173</u>
Diluted	<u>38,399</u>	<u>35,577</u>
Earnings per share:		
Basic–		
Continuing operations	\$ 0.43	\$ 0.92
Discontinued operations	0.01	—
Total	<u>\$ 0.44</u>	<u>\$ 0.92</u>
Diluted–		
Continuing operations	\$ 0.43	\$ 0.91
Discontinued operations	0.01	—
Total	<u>\$ 0.44</u>	<u>\$ 0.91</u>
Dividends paid per share of common stock	<u>\$ 0.35</u>	<u>\$ 0.34</u>

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, 2008	December 31, 2007*	March 31, 2007*
	(in thousands, except share amounts)		
<b>ASSETS</b>			
Current assets:			
Cash and cash equivalents	\$ 75,605	\$ 80,960	\$ 77,836
Restricted cash	5,484	5,443	2,032
Short-term investments	7,290	—	—
Receivables (net of allowance for doubtful accounts of \$4,213; \$4,588 and \$3,647, respectively)	270,763	289,244	223,179
Materials, supplies and fuel	87,937	95,968	110,129
Derivative assets	46,337	35,921	38,263
Deferred income taxes	14,011	4,512	—
Other assets	16,048	14,569	8,876
Assets of discontinued operations	1,106	1,052	1,444
	<u>524,581</u>	<u>527,669</u>	<u>461,759</u>
Investments	<u>16,745</u>	<u>19,216</u>	<u>23,613</u>
Property, plant and equipment	2,564,259	2,490,565	2,297,519
Less accumulated depreciation and depletion	(689,997)	(667,031)	(615,597)
	<u>1,874,262</u>	<u>1,823,534</u>	<u>1,681,922</u>
Other assets:			
Derivative assets	1,360	2,492	1,321
Goodwill	40,501	29,577	30,563
Intangible assets (net of accumulated amortization of \$28,865; \$28,114 and \$26,632, respectively)	20,275	21,026	23,650
Other	47,343	46,120	63,299
	<u>109,479</u>	<u>99,215</u>	<u>118,833</u>
	<u>\$ 2,525,067</u>	<u>\$ 2,469,634</u>	<u>\$ 2,286,127</u>
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>			
Current liabilities:			
Accounts payable	\$ 242,048	\$ 239,581	\$ 237,789
Accrued liabilities	104,808	116,197	91,217
Derivative liabilities	72,526	39,380	16,360
Deferred income taxes	—	—	1,352
Notes payable	73,000	37,000	—
Current maturities of long-term debt	143,187	143,183	38,822
Accrued income taxes	303	833	12,489
Liabilities of discontinued operations	757	1,551	1,858
	<u>636,629</u>	<u>577,725</u>	<u>399,887</u>
Long-term debt, net of current maturities	<u>561,136</u>	<u>564,372</u>	<u>602,870</u>
Deferred credits and other liabilities:			
Deferred income taxes	209,272	207,735	197,937
Derivative liabilities	16,516	9,375	3,973
Other	131,032	135,405	126,411
	<u>356,820</u>	<u>352,515</u>	<u>328,321</u>
Minority interest in subsidiaries	<u>5,244</u>	<u>5,167</u>	<u>5,252</u>
Stockholders' equity:			
Common stock equity –			
Common stock \$1 par value; 100,000,000 shares authorized; Issued 38,425,006; 37,842,221 and 37,701,238 shares, respectively	38,425	37,842	37,701
Additional paid-in capital	578,742	560,475	554,040
Retained earnings	400,909	397,393	369,997
Treasury stock at cost – 29,400; 45,916 and 37,128 shares, respectively	(1,050)	(1,347)	(984)
Accumulated other comprehensive loss	(51,788)	(24,508)	(10,957)
	<u>965,238</u>	<u>969,855</u>	<u>949,797</u>
	<u>\$ 2,525,067</u>	<u>\$ 2,469,634</u>	<u>\$ 2,286,127</u>

\* As adjusted (see Note 2)

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

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

	Three Months Ended March 31,	
	2008	2007*
	(in thousands)	
Operating activities:		
Net income	\$ 16,791	\$ 32,453
(Income) loss from discontinued operations, net of taxes	(219)	47
Income from continuing operations	16,572	32,500
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	25,644	23,168
Net change in derivative assets and liabilities	7,745	(20,982)
Deferred income taxes	8,830	13,842
Distributed earnings in associated companies	1,241	472
Allowance for funds used during construction – equity	(281)	(1,834)
Change in operating assets and liabilities:		
Materials, supplies and fuel	22,374	11,838
Accounts receivable and other current assets	(17,972)	41,121
Accounts payable and other current liabilities	(6,233)	4,682
Other operating activities	(4,435)	(10,705)
Net cash provided by operating activities of continuing operations	53,485	94,102
Net cash provided by (used in) operating activities of discontinued operations	196	(1,387)
Net cash provided by operating activities	53,681	92,715
Investing activities:		
Property, plant and equipment additions	(74,289)	(38,558)
Increase in short-term investments	(7,290)	—
Other investing activities	951	(305)
Net cash used in investing activities of continuing operations	(80,628)	(38,863)
Net cash provided by investing activities of discontinued operations	—	1,200
Net cash used in investing activities	(80,628)	(37,663)
Financing activities:		
Dividends paid	(13,275)	(11,377)
Common stock issued	1,998	146,638
Increase (decrease) in short-term borrowings, net	36,000	(145,500)
Long-term debt – repayments	(3,232)	(3,753)
Other financing activities	297	(350)
Net cash provided by (used in) financing activities of continuing operations	21,788	(14,342)
Net cash provided by (used in) financing activities of discontinued operations	—	—
Net cash provided by (used in) financing activities	21,788	(14,342)
(Decrease) increase in cash and cash equivalents	(5,159)	40,710
Cash and cash equivalents:		
Beginning of period	81,255 <sup>(b)</sup>	37,530 <sup>(d)</sup>
End of period	\$ 76,096 <sup>(a)</sup>	\$ 78,240 <sup>(c)</sup>
Supplemental disclosure of cash flow information:		
Non-cash investing and financing activities-		
Property, plant and equipment acquired with accrued liabilities	\$ 25,480	\$ 25,892
Cash paid during the period for-		
Interest (net of amounts capitalized)	\$ 7,864	\$ 9,282
Income taxes paid (net of amounts refunded)	\$ 1,500	\$ 6,538

\* As adjusted (see Note 2)

- (a) Includes approximately \$0.5 million of cash included in the assets of discontinued operations.
- (b) Includes approximately \$0.3 million of cash included in the assets of discontinued operations.
- (c) Includes approximately \$0.4 million of cash included in the assets of discontinued operations.
- (d) Includes approximately \$0.6 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 2007 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) 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, the Company believes 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 the Company's 2007 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, 2008, December 31, 2007 and March 31, 2007 financial information and are of a normal recurring nature. Some of the Company's 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. The results of operations for the three months ended March 31, 2008, 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.

#### (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. The Company applies fair value measurements to certain assets and liabilities, primarily commodity derivatives within our Energy marketing and Oil and gas business segments, interest rate swap instruments, and other miscellaneous derivatives.

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. As of January 1, 2008, the Company adopted the provisions of SFAS 157 for all assets and liabilities measured at fair value except for non-financial assets and liabilities measured at fair value on a non-recurring basis, as permitted by FSP FAS 157-2. As a result of the Company's adoption of SFAS 157, the Company discontinued its use of a "liquidity reserve" in valuing the total forward positions within its 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 being recorded within our unrealized marketing margins. Unrealized margins are presented as a component of Revenues on the accompanying Condensed Consolidated Statement of Income. SFAS 157 also required new disclosures regarding the level of pricing observability associated with instruments carried at fair value. This additional disclosure is provided in Note 12.

#### FSP FAS 157-1

In February 2008, the FASB issued FSP FAS 157-1, which excludes SFAS 13 and other accounting pronouncements that address fair value for purposes of lease classification and measurement under SFAS 13 from SFAS 157 except when applying SFAS 157 to assets acquired and liabilities assumed in a business combination. The Company adopted FSP FAS 157-1 effective January 1, 2008. Accordingly, the provisions of SFAS 157 will not be applied to lease transactions under SFAS 13 except when applying SFAS 157 to business combinations recorded by the Company.

#### 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). The Company adopted FSP FAS 157-2 effective January 1, 2008. Accordingly, the provisions of SFAS 157 will not be 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. Management is currently evaluating the impact, if any, that the deferred provisions of SFAS 157 will have on the Company's consolidated financial statements.

#### SFAS 159

SFAS 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value, with changes in fair value recognized in earnings. SFAS 159 was adopted on January 1, 2008 and did not have an impact on the Company's consolidated financial position, results of operations or cash flows.

## FSP FIN 39-1

FSP FIN 39-1 amends certain paragraphs of FIN 39 to permit 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. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007. The Company adopted FSP FIN 39-1 effective January 1, 2008. This standard changed our method of netting certain balance sheet amounts. The Company applied FSP FIN 39-1 as a change in accounting principle through retrospective application. 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. Accordingly, December 31, 2007 and March 31, 2007 amounts have been reclassified to conform to this presentation as follows (in thousands):

<u>Balance Sheet Line Description</u>	<u>As Reported for the 2007 10-K</u>	<u>FSP FIN 39-1 Reclassification</u>	<u>As Reported for the March 2008 10-Q</u>
Current assets:			
Receivables	\$ 291,189	\$ (1,945)	\$ 289,244
Derivative assets	\$ 37,208	\$ (1,287)	\$ 35,921
Current liabilities:			
Accounts payable	\$ 242,813	\$ (3,232)	\$ 239,581

<u>Balance Sheet Line Description</u>	<u>As Reported for the March 2007 10-Q</u>	<u>FSP FIN 39-1 Reclassification</u>	<u>As Reported for the March 2008 10-Q</u>
Current assets:			
Receivables	\$ 237,335	\$ (14,156)	\$ 223,179
Derivative assets	\$ 25,906	\$ 12,357	\$ 38,263
Current liabilities:			
Derivative liabilities	\$ 18,159	\$ (1,799)	\$ 16,360

The affect on the Cash Flow Statement for 2007 due to the reclassification is as follows (in thousands):

<u>Cash Flow Statement Operating Activities Line Description</u>	<u>As Reported for the March 2007 10-Q</u>	<u>FSP FIN 39-1 Reclassification</u>	<u>As Reported for the March 2008 10-Q</u>
Net change in derivative assets and liabilities	\$ (3,948)	\$ (17,034)	\$ (20,982)
Accounts receivable and other current assets	\$ 26,965	\$ 14,156	\$ 41,121
Accounts payable and other current liabilities	\$ 1,804	\$ 2,878	\$ 4,682

As of March 31, 2008, December 31, 2007 and March 31, 2007, the Company offset fair value cash collateral receivables and payables against net derivative positions in the amounts of \$32.9 million, \$(1.3) million and \$14.2 million, respectively.

(3) RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

SFAS 141(R)

In December 2007, the FASB issued SFAS 141(R). SFAS 141(R) requires an acquiring entity to recognize the assets acquired, the liabilities assumed and any non-controlling interests in the acquiree at the acquisition date to be measured at their fair values as of the acquisition date, with limited exceptions specified in the statement. This replaces the cost allocation process in SFAS 141, which required the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. Acquisition-related costs will be expensed in the periods in which the costs are incurred or services are rendered. 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. Management is currently evaluating the impact SFAS 141(R) will have on the Company's consolidated financial statements.

SFAS 160

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

- ownership interests in subsidiaries held by other 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 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.

SFAS 160 is effective for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Management does not expect the adoption of SFAS 160 to have a significant effect on the Company's consolidated financial statements.

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. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company is currently evaluating the impact of adoption of SFAS 161.

(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):

<u>Major Classification</u>	<u>March 31,</u> <u>2008</u>	<u>December 31,</u> <u>2007</u>	<u>March 31,</u> <u>2007</u>
Materials and supplies	\$ 35,788	\$ 35,037	\$ 33,303
Fuel	1,749	5,025	6,096
Gas and oil held by Energy marketing*	50,400	55,906	70,730
Total materials, supplies and fuel	<u>\$ 87,937</u>	<u>\$ 95,968</u>	<u>\$ 110,129</u>

\* As of March 31, 2008, December 31, 2007 and March 31, 2007, market adjustments related to natural gas held by Energy marketing and recorded in inventory were \$4.6 million, \$(9.8) million and \$2.4 million, respectively (see Note 11 for further discussion of Energy marketing trading activities).

The inventory held by the Company's Energy marketing subsidiary 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) LONG-TERM DEBT

The Company has classified the \$128.3 million Wygen I project debt to current maturities as the debt has a maturity date of June 2008. The Company initially intends to refinance this debt through borrowings on the revolving credit facility until permanent financing is completed.

(6) 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):

<u>Period ended March 31, 2008</u>	<u>Three Months</u>	
	<u>Income</u>	<u>Average Shares</u>
Income from continuing operations	<u>\$ 16,572</u>	
Basic earnings	16,572	37,826
Dilutive effect of:		
Stock options	—	80
Estimated contingent shares issuable for prior acquisition	—	397
Others	—	96
Diluted earnings	<u>\$ 16,572</u>	<u>38,399</u>

<u>Period ended March 31, 2007</u>	<u>Three Months</u>	
	<u>Income</u>	<u>Average Shares</u>
Income from continuing operations	<u>\$ 32,500</u>	
Basic earnings	32,500	35,173
Dilutive effect of:		
Stock options	—	102
Estimated contingent shares issuable for prior acquisition	—	158
Others	—	144
Diluted earnings	<u>\$ 32,500</u>	<u>35,577</u>

Basic average shares include the weighted-average effect of the issuance of 451,465 common shares on March 21, 2008 and 4,170,891 common shares on February 27, 2007 (see Notes 8 and 13 for discussion of the March 21, 2008 share issuance).

(7) OTHER COMPREHENSIVE INCOME

The following table presents the components of the Company's other comprehensive income (in thousands):

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
Net income	\$ 16,791	\$ 32,453
Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of \$14,951 and \$2,499, respectively)	(27,433)	(4,691)
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of \$(152) and \$3,065, respectively)	273	(5,751)
Unrealized loss on available for sale securities (net of tax of \$65)	(120)	—
	<u>          </u>	<u>          </u>
Other comprehensive (loss) income	<u>\$ (10,489)</u>	<u>\$ 22,011</u>

Other comprehensive loss on fair value adjustments on derivatives designated as cash flow hedges in the three months ended March 31, 2008 is primarily attributable to higher gas prices affecting the fair value of natural gas swaps at 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, 2008	<u>\$ (45,379)</u>	<u>\$ (6,115)</u>	<u>\$ (174)</u>	<u>\$ (120)</u>	<u>\$ (51,788)</u>
As of December 31, 2007	<u>\$ (18,178)</u>	<u>\$ (6,115)</u>	<u>\$ (215)</u>	<u>\$ —</u>	<u>\$ (24,508)</u>
As of March 31, 2007	<u>\$ (2,352)</u>	<u>\$ (8,404)</u>	<u>\$ (201)</u>	<u>\$ —</u>	<u>\$ (10,957)</u>

(8) COMMON STOCK

Other than the following transactions, the Company had no other material changes in its common stock, as reported in Note 9 of the Notes to Consolidated Financial Statements in the Company's 2007 Annual Report on Form 10-K.

Issuance of Unregistered Securities

On March 21, 2008, the Company issued 451,465 common shares as additional consideration associated with the "Acquisition Earn-out Litigation" previously disclosed in Note 18 of the Company's 2007 Annual Report on Form 10-K. No additional consideration was received in exchange for the earn-out shares (see Note 13).

Equity Compensation Plans

- Effective January 1, 2008, the Company granted 32,371 target performance shares to certain officers and business unit leaders of the Company for the January 1, 2008 through December 31, 2010 performance period. Performance shares are awarded based on the Company's total shareholder return over the designated performance period as measured against a selected peer group and can range from 0 to 175 percent of target. In addition, the Company's 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 percent in the form of cash and 50 percent in the form of common stock. The grant date fair value was \$46.00 per share.
- The Company issued 32,568 shares of common stock under the 2007 short-term incentive compensation plan during the three months ended March 31, 2008. Pre-tax compensation cost related to the award was approximately \$1.2 million, which was accrued for in 2007.
- The Company granted 35,157 restricted common shares during the three months ended March 31, 2008. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately \$1.5 million will be recognized over the three-year vesting period.
- 70,547 stock options were exercised during the three months ended March 31, 2008, at a weighted-average exercise price of \$25.01 per share providing \$1.8 million of proceeds to the Company.
- Total compensation expense recognized for all equity compensation plans for the three months ended March 31, 2008 and 2007 was \$0.2 million and \$1.0 million, respectively.

(9) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plan

The Company has two non-contributory defined benefit pension plans (Plans). One Plan covers employees of the Company and the following subsidiaries who meet certain eligibility requirements: Black Hills Service Company, Black Hills Power, WRDC and BHEP. The other Plan covers employees of the Company's subsidiary, Cheyenne Light, who meet certain eligibility requirements.

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

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
Service cost	\$ 754	\$ 687
Interest cost	1,230	1,129
Expected return on plan assets	(1,573)	(1,374)
Prior service cost	41	38
Net loss	—	127
	<hr/>	<hr/>
Net periodic benefit cost	<u>\$ 452</u>	<u>\$ 607</u>

The Company made a \$0.5 million contribution to the Cheyenne Light Pension Plan in the first quarter of 2008; no additional contributions are anticipated to be made to the Plans during the 2008 fiscal year.

Supplemental Non-qualified Defined Benefit Plans

The Company has various supplemental retirement plans for key executives of the Company (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,	
	<u>2008</u>	<u>2007</u>
Service cost	\$ 112	\$ 103
Interest cost	311	289
Prior service cost	3	3
Net loss	142	178
	<hr/>	<hr/>
Net periodic benefit cost	<u>\$ 568</u>	<u>\$ 573</u>

The Company anticipates that it will need to make contributions to the Supplemental Plans for the 2008 fiscal year of approximately \$0.8 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 the Company's 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,	
	<u>2008</u>	<u>2007</u>
Service cost	\$ 125	\$ 135
Interest cost	217	207
Net transition obligation	15	15
Net gain/loss	(20)	(4)
	<hr/>	<hr/>
Net periodic benefit cost	\$ 337	\$ 353

The Company anticipates that it will make contributions to the Healthcare Plans for the 2008 fiscal year of approximately \$0.3 million. The contributions are expected to be made in the form of benefits payments.

It has been determined that the Company's 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, 2008 and 2007.

(10) SUMMARY OF INFORMATION RELATING TO SEGMENTS OF THE COMPANY'S BUSINESS

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of March 31, 2008, substantially all of the Company's operations and assets are located within the United States.

The Company conducts its operations through the following six reporting segments:

Utilities group –

- Electric utility, which supplies electric utility service to western South Dakota, northeastern Wyoming and southeastern Montana; and
- Electric and gas utility, which supplies electric and gas utility service to Cheyenne, Wyoming and vicinity.

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 with power plants concentrated in Colorado, Nevada, Wyoming and California;
- Coal mining, which engages in the mining and sale of coal from its 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 20 of the Notes to Consolidated Financial Statements in the Company's 2007 Annual Report on Form 10-K. In accordance with the provisions of SFAS 71, intercompany fuel sales to the electric utilities are not eliminated.

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

	<u>External Operating Revenues</u>	<u>Inter-segment Operating Revenues</u>	<u>Income (Loss) from Continuing Operations</u>
<u>Three Month Period Ended March 31, 2008</u>			
Utilities:			
Electric utility	\$ 57,326	\$ 306	\$ 5,576
Electric and gas utility	41,976	—	4,591
Non-regulated energy:			
Oil and gas	26,122	—	2,551
Power generation	28,674	6,551	4,316
Coal mining	7,889	5,358	1,629
Energy marketing	6,119	—	299
Corporate	—	—	(2,390)
Inter-segment eliminations	—	(1,110)	—
Total	<u>\$ 168,106</u>	<u>\$ 11,105</u>	<u>\$ 16,572</u>

	<u>External Operating Revenues</u>	<u>Inter-segment Operating Revenues</u>	<u>Income (Loss) from Continuing Operations</u>
<u>Three Month Period Ended March 31, 2007</u>			
Utilities:			
Electric utility	\$ 47,356	\$ 411	\$ 6,699
Electric and gas utility	36,363	—	3,072
Non-regulated energy:			
Oil and gas	25,843	—	3,591
Power generation	39,566	—	4,979
Coal mining	6,217	3,528	1,615
Energy marketing	28,437	—	12,659
Corporate	1	—	(115)
Inter-segment eliminations	—	(1,189)	—
Total	<u>\$ 183,783</u>	<u>\$ 2,750</u>	<u>\$ 32,500</u>

During 2008, the Company added assets of approximately \$24.4 million on the ongoing construction of the Wygen III power plant within the Electric utility segment; approximately \$8.3 million for development costs related to the Aquila asset acquisition; and approximately \$18.0 million on assets related to the construction of the Valencia project, expected to be in commercial operation in the second quarter of 2008, in the Power generation segment. Other than these significant additions the Company had no additional material changes in the assets of its reporting segments, as reported in Note 20 of the Notes to Consolidated Financial Statements in the Company's 2007 Annual Report on Form 10-K.

(11) RISK MANAGEMENT ACTIVITIES

The Company actively manages its exposure to certain market risks as described in Note 2 of the Notes to Consolidated Financial Statements in the Company's 2007 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

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

	<u>Outstanding at March 31, 2008</u>		<u>Outstanding at December 31, 2007</u>		<u>Outstanding at March 31, 2007</u>	
	<u>Notional Amounts</u>	<u>Latest Expiration (months)</u>	<u>Notional Amounts</u>	<u>Latest Expiration (months)</u>	<u>Notional Amounts</u>	<u>Latest Expiration (months)</u>
(in thousands of MMBtus)						
Natural gas basis						
swaps purchased	187,068	33	125,577	36	169,341	21
Natural gas basis						
swaps sold	191,738	33	128,892	36	178,563	21
Natural gas fixed for float						
swaps purchased	53,738	24	42,326	24	40,323	24
Natural gas fixed for float						
swaps sold	67,910	24	59,253	24	61,880	24
Natural gas physical						
purchases	132,559	12	90,583	15	104,393	19
Natural gas physical sales	136,687	24	98,888	27	109,593	31
Natural gas options						
purchased	11,311	12	3,472	10	33,839	9
Natural gas options sold	11,311	12	3,472	10	33,839	9

	<u>Outstanding at</u> <u>March 31, 2008</u>		<u>Outstanding at</u> <u>December 31, 2007</u>		<u>Outstanding at</u> <u>March 31, 2007</u>	
	<u>Notional</u> <u>Amounts</u>	<u>Latest</u>	<u>Notional</u> <u>Amounts</u>	<u>Latest</u>	<u>Notional</u> <u>Amounts</u>	<u>Latest</u>
		<u>Expiration</u> <u>(months)</u>		<u>Expiration</u> <u>(months)</u>		<u>Expiration</u> <u>(months)</u>
(in thousands of Bbls)						
Crude oil physical purchases	3,737	9	4,991	12	1,806	6
Crude oil physical sales	2,903	9	3,800	12	1,557	6
Crude oil swaps purchased	495	9	495	12	450	12
Crude oil swaps sold	545	9	495	12	450	12
(Dollars, in thousands)						
Canadian dollars purchased	\$ 27,000	1	\$ 28,000	2	\$ 13,817	1

Derivatives and certain natural gas and crude oil marketing activities were marked to fair value on March 31, 2008, December 31, 2007 and March 31, 2007, 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):

	<u>Current</u> <u>Derivative</u> <u>Assets</u>	<u>Non-current</u> <u>Derivative</u> <u>Assets</u>	<u>Current</u> <u>Derivative</u> <u>Liabilities</u>	<u>Non-current</u> <u>Derivative</u> <u>Liabilities</u>	<u>Cash</u> <u>Collateral</u> <u>Included in</u> <u>Derivative</u> <u>Assets/</u> <u>Liabilities</u>	<u>Unrealized</u> <u>(Loss) Gain</u>
March 31, 2008	\$ 45,542	\$ 1,246	\$ 21,393	\$ 994	\$ (32,876)	\$ (8,475)
December 31, 2007	\$ 30,999	\$ 1,901	\$ 16,908	\$ 2,482	\$ 1,287	\$ 14,797
March 31, 2007	\$ 32,447	\$ 149	\$ 12,897	\$ 514	\$ (14,156)	\$ 5,029

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. Accordingly, December 31, 2007 and March 31, 2007 amounts have been reclassified to conform to this presentation.

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 inventory on the 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, 2008, December 31, 2007 and March 31, 2007, the market adjustments recorded in inventory were \$4.6 million, \$(9.8) million and \$2.4 million, respectively.

## Activities Other Than Trading

### Oil and Gas Exploration and Production

On March 31, 2008, December 31, 2007 and March 31, 2007, the Company had the following derivatives and related balances (in thousands):

	<u>Notional*</u>	<u>Maximum Terms in Years</u>	<u>Current Derivative Assets</u>	<u>Non- current Derivative Assets</u>	<u>Current Derivative Liabilities</u>	<u>Non- current Derivative Liabilities</u>	<u>Pre-tax Accumulated Other Comprehensive Income (Loss)</u>	<u>Pre-tax Income (Loss)</u>
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)	—
			<u>\$ 550</u>	<u>\$ 114</u>	<u>\$ 16,731</u>	<u>\$ 5,515</u>	<u>\$ (22,066)</u>	<u>\$ 484</u>
December 31, 2007								
Crude oil swaps/options	495,000	1.00	\$ 352	\$ —	\$ 3,506	\$ 1,794	\$ (5,300)	\$ 352
Natural gas swaps	11,406,000	1.59	4,332	591	507	825	3,587	4
			<u>\$ 4,684</u>	<u>\$ 591</u>	<u>\$ 4,013</u>	<u>\$ 2,619</u>	<u>\$ (1,713)</u>	<u>\$ 356</u>
March 31, 2007								
Crude oil swaps/options	450,000	1.00	\$ 649	\$ —	\$ 934	\$ 546	\$ (1,415)	\$ 584
Natural gas swaps	11,613,000	1.17	5,049	276	2,260	2,151	1,638	(724)
			<u>\$ 5,698</u>	<u>\$ 276</u>	<u>\$ 3,194</u>	<u>\$ 2,697</u>	<u>\$ 223</u>	<u>\$ (140)</u>

\*crude in Bbls, gas in MMBtus

Based on March 31, 2008 market prices, a \$17.1 million loss 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, December 31, 2007 and March 31, 2007, the Company had the following swaps and related balances (in thousands):

	<u>Notional*</u>	<u>Maximum Terms in Months</u>	<u>Current Derivative Assets</u>	<u>Non- current Derivative Assets</u>	<u>Current Derivative Liabilities</u>	<u>Non- current Derivative Liabilities</u>	<u>Pre-tax Accumulated Other Comprehensive Income (Loss)</u>	<u>Unrealized Gain</u>
March 31, 2008								
Natural gas swaps	300,000	1	\$ 245	\$ —	\$ 245	\$ —	\$ —	\$ —
December 31, 2007								
Natural gas swaps	610,000	4	\$ 238	\$ —	\$ 68	\$ —	\$ 170	\$ —
March 31, 2007								
Natural gas swaps	455,000	12	\$ —	\$ —	\$ 161	\$ —	\$ (161)	\$ —

\*gas in MMBtus

Based on March 31, 2008 market prices, no gain or loss would be realized and reported in pre-tax earnings during the next twelve months related to the cash flow hedges. Estimated and actual realized losses will likely change during the next twelve months as market prices change.

## Financing Activities

On March 31, 2008, December 31, 2007 and March 31, 2007, the Company's 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
March 31, 2008								
Interest rate swaps	<u>\$ 150,000</u>	5.04%	8.50	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 3,534</u>	<u>\$ 10,007</u>	<u>\$ (13,541)</u>
December 31, 2007								
Interest rate swaps	<u>\$ 150,000</u>	5.04%	8.75	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 1,792</u>	<u>\$ 4,274</u>	<u>\$ (6,066)</u>
March 31, 2007								
Interest rate swaps	<u>\$ 150,000</u>	5.04%	9.50	<u>\$ 118</u>	<u>\$ 896</u>	<u>\$ 108</u>	<u>\$ 762</u>	<u>\$ 144</u>

Based on March 31, 2008 market interest rates and balances, a loss of approximately \$3.5 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.

In addition to the interest rate swaps above, during the third quarter of 2007, the Company entered into forward starting interest rate swaps with a total notional amount of \$250.0 million to hedge the risk of interest rate movement between the hedge dates and the expected pricing date for a portion of the Company's anticipated 2008 long-term debt financings. The swaps have a mandatory early termination date of June 30, 2008. As of March 31, 2008, the mark-to-market value was \$(30.6) million. These swaps are designated as cash flow hedges and accordingly, any resulting gain or loss will be recorded in "Accumulated other comprehensive loss" on the Condensed Consolidated Balance Sheet and amortized into earnings as additional interest income or expense over the life of the related long-term financing.

(12) FAIR VALUE MEASUREMENTS

**Adoption of SFAS 157**

Effective January 1, 2008, the Company adopted SFAS 157 as discussed in Note 2, which, among other things, requires enhanced disclosures about assets and liabilities carried at fair value.

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. As permitted under SFAS 157, the Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing a significant portion of its assets and liabilities measured and reported at fair value. SFAS 157 also requires enhanced disclosures and establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values giving the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The Company is able to classify fair value balances based on the observability of inputs.

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

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

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

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

The following table sets forth by level within the fair value hierarchy the Company's assets and liabilities that were accounted for at fair value on a recurring basis as of 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. The Company's 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, 2008

	<u>Level 1</u>	<u>Level 2</u>	<u>Level 3</u>	<u>Counterparty Netting (a)</u>	<u>Total</u>
<b>Assets:</b>					
Short-term investments	\$ —	\$ —	\$ 7,290	\$ —	\$ 7,290
Commodity derivatives	32,876	89,452	12,549	(87,180)	47,697
<b>Total</b>	<b>\$ 32,876</b>	<b>\$ 89,452</b>	<b>\$ 19,839</b>	<b>\$ (87,180)</b>	<b>\$ 54,987</b>
<b>Liabilities:</b>					
Commodity derivatives	\$ —	\$ 126,127	\$ 5,576	\$ (87,180)	\$ 44,523
Interest rate swaps	—	44,164	—	—	44,164
Foreign currency derivatives	—	355	—	—	355
<b>Total</b>	<b>\$ —</b>	<b>\$ 170,646</b>	<b>\$ 5,576</b>	<b>\$ (87,180)</b>	<b>\$ 89,042</b>

- (a) FIN 39 permits the netting of receivables and payables when a legally enforceable master netting agreement exists between the Company and a 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.

The following table presents the changes in level 3 recurring fair value for the three months ended March 31, 2008 (in thousands):

	<u>Three Months Ended March 31, 2008</u>		
	<u>Commodity Derivatives</u>	<u>Short-term Investments</u>	<u>Total</u>
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
<b>Balances as of March 31, 2008</b>	<b>\$ 6,973</b>	<b>\$ 7,290</b>	<b>\$ 14,263</b>
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 Condensed Consolidated Statement of Income. Short-term investments included in level 3 represent auction rate securities held at March 31, 2008. The Company believes 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. The unrealized losses for these investments are recognized in Accumulated other comprehensive income on the Condensed Consolidated Balance Sheet.

## (13) COMMITMENTS AND CONTINGENCIES

The Company is subject to various legal proceedings, claims and litigation as described in Note 18 of the Notes to Consolidated Financial Statements in the Company's 2007 Annual Report on Form 10-K.

### **Las Vegas I Tolling Agreement**

As discussed under "Las Vegas Cogeneration/Nevada Power Arbitration" within this Note 13, the Company has entered into an agreement for 50 MW of the output of the 53 MW Las Vegas I plant with Nevada Power. The contract is a tolling agreement whereby Nevada Power is responsible for supplying natural gas. The terms of the contract are for the months of June through September for each of the years beginning in 2008 and ending in 2017. The Las Vegas I plant is included in the pending sale of the power generation assets (see Note 16).

## **LEGAL PROCEEDINGS**

### **Earn-Out Litigation**

As disclosed in previous filings with the SEC, the Company has been defending two litigation proceedings brought by the former Indeck stockholders. The first proceeding is a civil lawsuit that has been pending in federal court in Illinois. The second proceeding is an arbitration process brought under the terms of a Merger Agreement that provided for contingent payment of Earn-Out Consideration to the former Indeck stockholders. On March 21, 2008, the parties settled all claims in the lawsuit. Under the Settlement Agreement the Company agreed to pay additional Earn-Out Consideration to the former Indeck stockholders. The aggregate value of the 451,465 shares of additional Black Hills common stock issued was recorded as additional goodwill. The trial court entered its Order approving the Settlement Agreement on March 27, 2008.

The Merger Agreement provides a \$35.0 million "cap" or maximum amount of Earn-Out Consideration payable with respect to the Earn-Out provision. With the payment made in settlement of the litigation to date, the Company has paid in common stock an aggregate value of \$23.5 million. The Company asserts no additional Earn-Out Consideration is payable with respect to claims pending in arbitration. While any amount that could be awarded in the arbitration would be limited to the difference between the "cap" and the aggregate value paid to date, the former Indeck stockholders may seek additional payment, equivalent to interest and dividends on any such amount. The Company would oppose this claim as well.

The Order provides all lawsuit claims are dismissed without prejudice pending completion of the arbitration. The court retains jurisdiction over the parties for the purpose of enforcing the order entered in the pending arbitration. Once the parties submit a final order to the court upon completion of the arbitration, the dismissal of all claims will convert to a dismissal with prejudice.

The outcome of the matters remaining in the arbitration is uncertain, as is the amount of any Earn-Out Consideration that could be awarded following arbitration. If any additional consideration is awarded, it would be recorded as additional goodwill, which would be subject to a recoverability analysis under GAAP. An award of interest, if any, would be recorded as a charge to earnings.

## **Las Vegas Cogeneration/Nevada Power Company Arbitration**

As disclosed in previous filings with the SEC, the Company's wholly-owned subsidiary, LVC has been in an arbitration proceeding with Nevada Power concerning the power purchase agreement at our Las Vegas I facility. On December 4, 2007, the parties reached a settlement. The proposed Settlement Agreement was filed with the PUCN on December 14, 2007. The PUCN approved the settlement on April 4, 2008. The existing structure of LVC as a "qualifying facility" under federal law, together with existing contracts with Nevada Power have been terminated. LVC filed with the FERC to become an "exempt wholesale generator" with authority to sell power at market based rates. FERC granted the Company's request and issued its Order on March 4, 2008. LVC and Nevada Power reached agreement on the terms of a new Power Purchase Agreement that will replace the existing firm fuel supply and transportation agreements. The new Power Purchase Agreement likewise was approved by the PUCN.

Except as described above, 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 2008.

### (14) ACQUISITIONS

#### **Aquila**

On February 7, 2007, the Company entered into a definitive agreement with Aquila for the asset acquisition of Aquila's regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa. The purchase price of the assets is \$940 million, subject to closing adjustments.

The asset purchase is subject to regulatory approvals from the Missouri Public Service Commission, the Kansas Corporation Commission, the Colorado Public Utilities Commission, the Nebraska Public Service Commission, the Iowa Utilities Board and FERC; Hart-Scott-Rodino antitrust review; as well as other customary conditions. The Company has obtained state regulatory approval for the transfer of ownership in Iowa, Nebraska, Colorado and Kansas. At the federal level, the FERC has approved the acquisition of the Colorado Electric operation, and antitrust clearance has been obtained from the Federal Trade Commission.

The purchase is also conditioned on the completion of the acquisition of the outstanding shares of Aquila by Great Plains immediately following the sale of the assets of the regulated utilities to the Company. During October 2007, Great Plains and Aquila shareholders approved Great Plains' acquisition of Aquila. Great Plains and Aquila now await final regulatory approval needed from the Missouri Public Service Commission.

The Company is capitalizing certain incremental acquisition costs incurred related to this pending acquisition. Amounts capitalized at March 31, 2008 and 2007 were approximately \$27.4 million and \$2.0 million, respectively. In addition, the Company has expensed certain integration-related costs of approximately \$4.1 million and \$0.2 million for the three month periods ended March 31, 2008 and 2007, respectively.

(15) DISCONTINUED OPERATIONS

The Company accounts for its discontinued operations under the provisions of SFAS 144. Accordingly, results of operations and the related charges for discontinued operations have been classified as “Income (loss) 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 Crude Oil Marketing and Transportation Assets

On March 1, 2006, the Company sold the operating assets of BHER and related subsidiaries, its crude oil marketing and transportation business.

Net income (loss) from the discontinued operations was as follows (in thousands):

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
Pre-tax income (loss) from discontinued operations	\$ 192	\$ (73)
Income tax benefit	27	26
Net income (loss) from discontinued operations	<u>\$ 219</u>	<u>\$ (47)</u>

Income and losses incurred subsequent to the asset sale resulted from the settlement of certain contract disputes with the purchaser and other costs incurred in closing down the business operations. Assets and liabilities of the crude oil marketing and transportation business subsequent to the sale were not significant.

(16) SUBSEQUENT EVENTS

Definitive Agreement to Sell IPP Plants

On April 29, 2008, the Company entered into a definitive agreement to sell seven of its IPP plants to affiliates of Hastings and IIF. Under the agreement, the Company will receive a cash payment of \$840 million, subject to certain working capital adjustments. The transaction is subject to regulatory approval from the FERC, antitrust clearance under the Hart-Scott-Rodino Act, and completion of a federal review by the CFIUS, and is expected to be completed late in the second quarter or early third quarter of 2008.

Under the terms of the agreement, the Company has the right to retain ownership of the Fountain Valley 240 MW power plant in the event closing conditions for the Company’s planned acquisition of the Aquila utility assets are not met. The purchase price for the Fountain Valley plant represents \$240 million of the total \$840 million purchase price. The Company is also obligated to complete construction, startup and testing of the Valencia plant prior to the sale.

Assets and liabilities to be sold under the agreement are currently presented within the Power generation segment of our Non-regulated energy group and include the following (in thousands):

	March 31, <u>2008</u>
Current assets	\$ 21,990
Property, plant and equipment*	367,115
Other non-current assets	15,652
Current liabilities	(14,495)
Other non-current liabilities	<u>(30)</u>
Net assets**	<u>\$ 390,232</u>

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\* Under the definitive agreement, the Company is required to complete the construction of the Valencia plant and expects associated capital expenditures to approximate \$40.7 million.

\*\* The net asset value of the Fountain Valley plant of approximately \$143.1 million is excluded from the above table as the sale of the Fountain Valley plant is contingent on the acquisition of the Aquila utility assets. The net assets and operating activity for the Fountain Valley plant will not be recorded as discontinued operations until the contingency is met.

**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:

<b><u>Business Group</u></b>	<b><u>Financial Segment</u></b>
<i>Utilities group</i>	Electric utility Electric and gas utility
<i>Non-regulated energy group</i>	Oil and gas Power generation Coal mining Energy marketing

Our utilities group consists of our electric and gas utility segments. Our electric utility, Black Hills Power, generates, transmits and distributes electricity to an average of approximately 65,100 customers in South Dakota, Wyoming and Montana. Our electric and gas utility, Cheyenne Light, serves approximately 39,400 electric and 33,000 natural gas customers in Cheyenne, Wyoming and vicinity. 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 diversified 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.

**Definitive Agreement to Sell IPP Plants**

On April 29, 2008, we entered into a definitive agreement with affiliates of Hastings and IIF to sell seven IPP gas-fired plants with a total capacity of 974 MW for \$840 million cash, subject to certain working capital adjustments.

Under the terms of the agreement, we have the right to retain ownership of the Fountain Valley 240 MW power plant in Colorado in the event closing conditions for our planned acquisition of utility assets from Aquila are not met. The purchase price for the 240 MW Fountain Valley plant represents \$240 million of the total \$840 million purchase price.

In order to close, this transaction must receive regulatory approval from FERC, antitrust clearance under the Hart-Scott-Rodino Act, and completion of a federal review by the CFIUS. The closing of the sale, pending customary regulatory approvals, is expected to occur late second quarter or early third quarter of 2008.

The following power plants are included in the definitive agreement with Hastings and IIF:

Asset (State)	Capacity (net megawatts)
Fountain Valley (Colorado)*	240
Las Vegas II (Nevada)	224
Valencia (New Mexico, under construction)**	149
Arapahoe (Colorado)	130
Harbor Cogeneration (California)	98
Valmont (Colorado)	80
Las Vegas I (Nevada)	53
Total	974

\* We are not obligated to sell the Fountain Valley plant in the event that closing conditions are not met for our pending acquisition of the Aquila utility assets.

\*\* The definitive agreement requires us to complete the construction of the Valencia plant with the completion considered in the \$840 million sale price.

The following power plants will remain with the Company in the Power generation business segment of our Non-regulated energy group:

Asset (State)	Capacity (net megawatts)
Wygen I (Wyoming)*	90
Gillette Combustion Turbine (Wyoming)	40
Ontario Cogeneration (California)	12
Rupert and Glens Ferry Cogeneration (Idaho)**	11
Power fund investments (various locations)	5
Total	158

\* Mine-mouth coal-fired baseload generation

\*\* Capacity represents the Company's 50 percent interest in the two power plants

### Wygen III Power Plant Project

In March 2008, the Company received final regulatory approval for Wygen III. Construction began immediately and the 100 MW coal-fired base load electric generating facility is expected to take 24 to 30 months to complete. The expected cost of construction is approximately \$255 million, which includes AFUDC. We anticipate that Black Hills Power will have at least 55 MW of the facilities' capacity and we are considering third-party investors to own the remaining 45 MW. Definitive ownership structuring for the Wygen III plant is expected prior to the end of 2008.

### Valencia Power Plant Project

In April 2007, we entered into a power purchase agreement to provide electric power to Public Service Company of New Mexico, a regulated electric and natural gas utility subsidiary of PNM. Under the terms of the agreement, we will provide the capacity and energy of the Valencia 149 MW, simple-cycle gas turbine generation facility located near Albuquerque, New Mexico. The project is expected to cost approximately \$101 million, and has an expected commercial operation in-service date of June 2008. The Valencia plant is included in the pending sale of the power generation assets and the Company is obligated to complete construction, startup and testing of the plant prior to the sale.

### Pending Acquisition of Assets from Aquila

On February 7, 2007, we entered into a definitive agreement with Aquila for the asset acquisition of Aquila's regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa. The purchase price of the assets is \$940 million, subject to closing adjustments.

The asset purchase is subject to regulatory approvals from the Missouri Public Service Commission, the Kansas Corporation Commission, the Colorado Public Utilities Commission, the Nebraska Public Service Commission, the Iowa Utilities Board and FERC; Hart-Scott-Rodino antitrust review; as well as other customary conditions. We have obtained all required regulatory approvals including state regulatory approval for the transfer of ownership in Iowa, Nebraska, Colorado and Kansas. At the federal level, the FERC has approved our acquisition of the Colorado Electric operation, and antitrust clearance has been obtained from the Federal Trade Commission.

The purchase is also conditioned on the completion of the acquisition of the outstanding shares of Aquila by Great Plains immediately following the sale of the assets of the regulated utilities to us. During October 2007, Great Plains and Aquila shareholders approved Great Plains' acquisition of Aquila. Great Plains and Aquila now await the final regulatory approval needed from the Missouri Public Service Commission.

We are capitalizing certain incremental acquisition costs incurred related to this pending acquisition. Amounts capitalized at March 31, 2008 and 2007 were approximately \$27.4 million and \$2.0 million, respectively. In addition, we expensed certain integration-related costs of approximately \$4.1 million and \$0.2 million for the three month periods ended March 31, 2008 and 2007, respectively.

## Results of Operations

### Executive Summary

Results for the three months ended March 31, 2008 were lower than the same period of the prior year primarily due to lower earnings from the Non-regulated energy business group. Income from continuing operations for the three month period ended March 31, 2008 was \$16.6 million, or \$0.43 per share, compared to \$32.5 million, or \$0.91 per share, reported for the same period in 2007. For the three month period ended March 31, 2008, net income was \$16.8 million or \$0.44 per share, compared to \$32.5 million, or \$0.91 per share, for the same period in 2007.

Utilities earnings were affected by Cheyenne Light benefiting from a 2008 rate increase and the sale of excess generation from the Wygen II plant, partially offset by increased costs related to Wygen II plant operations and depreciation. Black Hills Power earnings decreased due to lower margins on retail sales as higher fuel and purchased power costs were partially offset by increased MWh sold, and higher margins from off-system sales.

Earnings from oil and gas operations decreased for the quarter driven by higher LOE and increased depletion expense, partially offset by an overall increase in revenues. Revenues for the quarter were negatively impacted by a \$2.1 million pre-tax accrual for a royalty settlement with the Jicarilla Apache Nation. First quarter 2008 production was 4 percent lower than first quarter 2007 primarily due to weather related impacts, federal drilling permit delays and lower production from non-operated properties. Average hedged oil prices increased 46 percent and average hedged gas prices decreased 3 percent exclusive of the impact of the royalty settlement in 2008.

Decreased earnings from power generation reflect lower earnings from the Harbor plant due to reduced contract termination payments, the suspension of operations at the Ontario plant and lower earnings from power fund investments. Operating expenses decreased primarily due to lower depreciation expense. The operation of Las Vegas I as a merchant plant until a new tolling contract with Nevada Power begins in June 2008 resulted in a decrease in revenues and fuel costs at that plant. The operations pertaining to the IPP plants to be sold to Hastings and IIF, excluding the Fountain Valley plant, will be reclassified to Discontinued operations beginning in the second quarter of 2008.

Earnings from energy marketing reflect lower realized margins received, lower volumes and higher unrealized mark-to-market losses. Margins were impacted by changes in market conditions as lower Rocky Mountain natural gas price basis differentials and calendar spreads contributed to the earnings decline. Lower operating expenses reflect lower incentive compensation related to the decreased earnings from realized gross margins.

Discontinued operations in 2008 and 2007 represent the continued close-out of operations related to our crude oil marketing and transportation business. The assets of this business were sold in March 2006.

## Consolidated Results

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

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
<u>Revenues</u>		
Utilities	\$ 99,302	\$ 83,719
Non-regulated energy	79,909	102,813
Corporate	—	1
	<u>\$ 179,211</u>	<u>\$ 186,533</u>
 <u>Income/(loss) from continuing operations</u>		
Utilities	\$ 10,167	\$ 9,771
Non-regulated energy	8,795	22,844
Corporate	(2,390)	(115)
	<u>\$ 16,572</u>	<u>\$ 32,500</u>

Income from continuing operations decreased \$15.9 million due primarily to the following:

- a \$12.4 million decrease in Energy marketing earnings;
- a \$1.1 million decrease in Electric utility earnings;
- a \$1.0 million decrease in Oil and gas earnings;
- a \$0.7 million decrease in Power generation earnings; and
- a \$2.3 million increase in unallocated corporate costs.

partially offset by:

- a \$1.5 million increase in Electric and gas utility 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.

The following business group and segment information does not include intercompany eliminations or results of discontinued operations.

## Utilities Group

### Electric Utility

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
	(in thousands)	
Revenue	\$ 57,632	\$ 47,767
Fuel and purchased power	27,499	17,035
Gross margin	<u>30,133</u>	<u>30,732</u>
Operating expenses	19,542	18,187
Operating income	<u>\$ 10,591</u>	<u>\$ 12,545</u>
Income from continuing operations and net income	<u>\$ 5,576</u>	<u>\$ 6,699</u>

The following tables provide certain operating statistics for the Electric utility segment:

	Electric Revenue (in thousands)		
	Three Months Ended March 31,		
Customer Base	2008	Percentage Change	2007
Commercial	\$ 13,484	3%	\$ 13,105
Residential	12,966	5	12,407
Industrial	5,296	4	5,096
Municipal sales	625	8	579
Total retail sales	<u>32,371</u>	4	<u>31,187</u>
Contract wholesale	6,931	7	6,457
Wholesale off system	<u>15,097</u>	129	<u>6,582</u>
Total electric sales	54,399	23	44,226
Other revenue	<u>3,233</u>	(9)	<u>3,541</u>
Total revenue	<u>\$ 57,632</u>	21%	<u>\$ 47,767</u>

### Megawatt Hours Sold

Customer Base	Three Months Ended March 31,		
	2008	Percentage Change	2007
Commercial	173,459	4%	166,094
Residential	163,034	7	152,736
Industrial	102,669	3	99,254
Municipal sales	8,208	11	7,420
Total retail sales	447,370	5	425,504
Contract wholesale	171,620	4	165,110
Wholesale off system	227,741	70	133,849
Total electric sales	846,731	17%	724,463

### Electric Utility Power Plant Availability

	Three Months Ended March 31,	
	2008	2007
Coal-fired plants	93.9%	95.3%
Other plants	93.9%	99.9%
Total availability	93.9%	97.3%

### Megawatt Hours Generated and Purchased

Resources	Three Months Ended March 31,		
	2008	Percentage Change	2007
Coal	432,882	(2)%	440,518
Gas	37,000	—	5,698
	469,882	5%	446,216
MWhs purchased	384,581	31%	294,463
Total resources	854,463	15%	740,679

### Heating Degree Days

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
Heating degree days:		
Actual—		
Heating degree days	3,361	3,055
Percent of normal—		
Heating degree days	102%	93%

**Three Months Ended March 31, 2008 Compared to Three Months Ended March 31, 2007.** Income from continuing operations decreased \$1.1 million, or 17 percent from the prior period primarily due to the following:

- A \$1.0 million reduction in retail sales margins due to increased fuel and purchased power costs, partially offset by a 5 percent increase in MWhs sold; and
- Increased operating expense due to increased repair and maintenance expenses, personnel costs, consulting fees and allocated corporate costs.

Partially offsetting the increased costs was the following:

- Margins from wholesale off-system sales increased \$0.7 million. Total MWhs increased 70 percent as Black Hills Power was able to market excess generation purchased from Cheyenne Light's Wygen II plant.

### Electric and Gas Utility

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
	(in thousands)	
Revenue	\$ 41,976	\$ 36,363
Fuel and purchased power and gas	24,615	28,588
Gross margin	17,361	7,775
Operating expenses	8,086	5,328
Operating income	\$ 9,275	\$ 2,447
Income from continuing operations and net income	\$ 4,591	\$ 3,072

The following tables provide certain operating statistics for the Electric and gas utility segment:

Electric Margins  
(in thousands)

Customer Base	Three Months Ended March 31, Percentage		
	2008	Change	2007
Retail sales	\$ 21,380	16%	\$ 18,363
Marketing sales	1,260	—	—
	22,640	23	18,363
Other	2,300	—	(62)
Total electric	24,940	36	18,301
Fuel and purchased power	12,755	(9)	14,014
Total electric margins	\$ 12,185	184%	\$ 4,287

Gas Margins  
(in thousands)

Customer Base	Three Months Ended March 31, Percentage		
	2008	Change	2007
Commercial	\$ 1,278	38%	\$ 926
Residential	3,492	60	2,185
Industrial	180	9	165
Total gas	4,950	51	3,276
Other	226	7	212
Total gas margins	\$ 5,176	48%	\$ 3,488

	Three Months Ended March 31, Percentage		
	2008	Change	2007
Electric sales - MWh	255,430	6%	241,830
Gas sales - Dth	2,156,320	9%	1,969,585

Electric and Gas Utility  
Power Plant Availability

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
Coal-fired plant*	92.2%	N/A

\*Placed in service January 1, 2008

Megawatt Hours Generated  
and Purchased

	Three Months Ended March 31,		
Resources	<u>2008</u>	Percentage Change	<u>2007</u>
Coal-fired generation	188,013	—%	—
MWhs purchased	<u>138,663</u>	(47)%	<u>261,290</u>
Total resources	<u><u>326,676</u></u>	25%	<u><u>261,290</u></u>

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
Heating degree days: Actual		
Heating degree days	<u>3,236</u>	<u>3,023</u>
Percent of normal		
Heating degree days	<u>103%</u>	<u>96%</u>

On January 1, 2008 Wygen II, a 95 MW baseload coal fired power plant commenced commercial service as a rate base asset to serve Cheyenne Light.

**Three Months Ended March 31, 2008 Compared to Three Months Ended March 31, 2007.** Income from continuing operations increased \$1.5 million for the three months ended March 31, 2008 compared to the three months ended March 31, 2007 primarily due to the following:

- Increased electric margins of \$7.9 million primarily due to an increase in electric rates effective January 1, 2008 and a 6 percent increase in MWh sales as well as the sale to Black Hills Power of surplus energy generated from the Wygen II plant;
- Purchased power decreased \$4.6 million from the prior period due to the availability of lower cost generation from the Wygen II plant; and
- Gas gross margins increased 48 percent primarily due to the increase in gas rates effective January 1, 2008 and a 9 percent increase in usage. We believe gross margins are a more useful performance measure as fluctuations in the cost of gas flows through to revenues through cost recovery rate adjustments.

Partially offsetting these increases were the following:

- Operating expenses increased \$2.8 million, or 52 percent, primarily due to Wygen II operating costs of approximately \$1.2 million and increased depreciation costs of approximately \$1.3 million for the Wygen II plant; and
- Decreased income from AFUDC due to the completion of Wygen II construction.

**Rate Increase.** In November 2007, the WPSC approved general rate increases of \$6.7 million for electric rates and \$4.4 million for natural gas rates to provide for increased costs of providing service. The electric rate increase also included placing the 95 MW, coal-fired Wygen II power plant into rate base. The WPSC also approved a new pass-through mechanism for Cheyenne Light's electric business. For calendar years beginning in 2008, the annual increase or decrease for transmission, fuel and purchased power costs is passed on to customers, subject to a \$1.0 million threshold. Under its tariff, Cheyenne Light collects or refunds 95 percent of the increase or decrease that is in excess of the \$1.0 million threshold. For changes in these costs that are less than the \$1.0 million annual threshold, Cheyenne Light absorbs the increase and likewise retains the savings. The new rates and tariffs were effective January 1, 2008.

## 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,	
	<u>2008</u>	<u>2007</u>
	(in thousands)	
Revenue	\$ 26,122	\$ 25,843
Operating expenses	20,489	18,499
Operating income	<u>\$ 5,633</u>	<u>\$ 7,344</u>
Income from continuing operations and net income	<u>\$ 2,551</u>	<u>\$ 3,591</u>

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

	Three Months Ended	
	March 31,	
	<u>2008</u>	<u>2007</u>
Fuel production:		
Bbls of oil sold	99,975	103,415
Mcf of natural gas sold	2,563,190	2,678,290
Mcf equivalent sales	3,163,040	3,298,780

	Three Months Ended	
	March 31,	
	<u>2008</u>	<u>2007</u>
Average Price Received <sup>(a)</sup> :		
Gas/Mcf <sup>(b)</sup>	\$ 7.46 <sup>(c)</sup>	\$ 7.68
Oil/Bbl	\$ 79.50	\$ 54.47
Depletion expense/Mcfe	\$ 2.33	\$ 2.04

(a) Net of hedge settlement gains/losses

(b) Exclusive of gas liquids

(c) Excludes \$2.1 million negative revenue impact for royalty settlement accrual

The following are summaries of LOE/Mcfe:

<u>Location</u>	<u>Three Months Ended March 31, 2008</u>			<u>Three Months Ended March 31, 2007</u>		
	<u>LOE</u>	<u>Gathering, Compression and Processing</u>	<u>Total</u>	<u>LOE</u>	<u>Gathering, Compression and Processing</u>	<u>Total</u>
New Mexico	\$ 1.54	\$ 0.44	\$ 1.98	\$ 1.26	\$ 0.43	\$ 1.69
Colorado	1.22	1.22 <sup>(a)</sup>	2.44	1.50	1.27 <sup>(a)</sup>	2.77
Wyoming	1.81	—	1.81	1.11	—	1.11
All other properties	1.32	(0.02)	1.30	0.84	0.21	1.05
All locations	\$ 1.52	\$ 0.27	\$ 1.79	\$ 1.13	\$ 0.32	\$ 1.45

(a) Reflects the expenses associated with Colorado acquisitions completed in 2006 which included underutilized gathering, processing and compression assets. The Company anticipates that future development of these properties will increase the capacity utilization rate of these gathering and processing assets and the per unit costs will decrease.

**Three Months Ended March 31, 2008 Compared to Three Months Ended March 31, 2007.** Income from continuing operations decreased \$1.0 million for the three months ended March 31, 2008 compared to the same period in 2007 primarily due to:

- A \$2.8 million decrease due to a royalty settlement, including interest and penalties, with the Jicarilla Apache Nation;
- A \$1.1 million increase in LOE due to industry-wide higher field service costs, costs related to severe weather conditions, increased regulatory compliance expenses and the impact of additional wells; and
- A \$0.5 million increase in depletion expense due to an increase in depletion rates per Mcfe resulting from the addition of higher average cost reserves over the prior year.

Partially offsetting these decreases was the following:

- Revenue increased \$0.3 million due to a 46 percent increase in the average hedged price of oil received, offset by a 3 percent decrease in oil production and a 4 percent decrease in gas production at an average hedged price of gas received that was 3 percent lower than the prior year. The lower production reflects weather impacts in the San Juan Basin, ongoing federal drilling permit delays, primarily in the Piceance Basin, and lower production from non-operated properties.

## Power Generation

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
	(in thousands)	
Revenue	\$ 35,225	\$ 39,566
Operating expenses	21,879	25,130
Operating income	<u>\$ 13,346</u>	<u>\$ 14,436</u>
Income from continuing operations and net income	<u>\$ 4,316</u>	<u>\$ 4,979</u>

The following table provides certain operating statistics for our Power generation segment:

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
Contracted power plant fleet availability:		
Coal-fired plant	95.0%	98.8%
Other plants	98.9%	95.5%
Total availability	98.6%	96.1%

**Three Months Ended March 31, 2008 Compared to Three Months Ended March 31, 2007.** Income from continuing operations decreased \$0.7 million due to:

- Lower earnings from the Harbor plant due to a \$0.9 million decrease in contract termination revenues and higher maintenance costs for unplanned repairs;
- Lower earnings from power fund investments of \$0.5 million due to the liquidation of these funds; and
- Increased allocated corporate costs.

Partially offsetting these decreases were the following:

- Increased earnings from Las Vegas II due to increased dispatch and lower maintenance costs; and
- Lower depreciation expense due to a decrease in componentized depreciation.

## Coal Mining

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
	(in thousands)	
Revenue	\$ 13,247	\$ 9,745
Operating expenses	11,617	8,128
Operating income	<u>\$ 1,630</u>	<u>\$ 1,617</u>
Income from continuing operations and net income	<u>\$ 1,629</u>	<u>\$ 1,615</u>

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

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
	(in thousands)	
Fuel production:		
Tons of coal sold	1,545	1,212

### **Three Months Ended March 31, 2008 Compared to Three Months Ended March 31, 2007.**

Income from continuing operations from our Coal mining segment for the three months ended March 31, 2008 was comparable to the same period in the prior year. Results were impacted by the following:

- Revenue increased \$3.5 million, or 36 percent, for the three month period ended March 31, 2008 compared to the same period in 2007. Revenues increased due to an increase in average price received and higher tons of coal sold, primarily due to additional sales to Cheyenne Light for Wygen II and increased train load-out sales.

Offsetting the increased revenue was the following:

- Operating expenses increased \$3.5 million, or 43 percent, during the three months ended March 31, 2008 primarily due to higher mining costs associated with higher revenues and production including increased coal taxes and increased overburden removal costs due to a 79 percent increase in cubic yards moved.

## Energy Marketing

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
	(in thousands)	
Revenue –		
Realized gas marketing gross margin	\$ 13,423	\$ 21,244
Unrealized gas marketing gross margin	(6,785)	6,526
Realized oil marketing gross margin	1,573	717
Unrealized oil marketing gross margin	(2,092)	(50)
	<u>6,119</u>	<u>28,437</u>
Operating expenses	<u>5,937</u>	<u>8,987</u>
Operating income	<u>\$ 182</u>	<u>\$ 19,450</u>
Income from continuing operations and net income	<u>\$ 299</u>	<u>\$ 12,659</u>

The following is a summary of average daily energy marketing volumes:

	Three Months Ended March 31,	
	<u>2008</u>	<u>2007</u>
Natural gas physical sales – MMBtus	1,794,090	1,898,630
Crude oil physical sales – Bbls	7,080	6,050

**Three Months Ended March 31, 2008 Compared to Three Months Ended March 31, 2007.** Income from continuing operations decreased \$12.4 million due to:

- A \$7.8 million pre-tax decrease in realized gas marketing margins primarily resulting from prevailing conditions in natural gas markets affecting both transportation and storage strategies. The Rockies Express Pipeline's west segment was placed into service during the quarter resulting in a compressed Rocky Mountain basis spread contributing to the decrease in margin. The decrease in realized gas marketing margins was partially offset by increased realized crude oil marketing margins that benefited from increased volumes and higher margins per barrel marketed. Physical volumes marketed decreased 6 percent for natural gas and increased 17 percent for crude oil; and
- A \$15.4 million pre-tax decrease in unrealized marketing margins.

Partially offsetting these decreases was the following:

- Lower compensation cost related to the decreased realized marketing margins.

## Corporate

**Three Months Ended March 31, 2008 Compared to Three Months Ended March 31, 2007.** Losses increased \$2.3 million due to increased unallocated costs in the three months ended March 31, 2008, compared to the same period in 2007, primarily as a result of increased transitional and integration costs of approximately \$2.7 million after-tax related to the pending purchase of certain Aquila assets. Offsetting the increase in unallocated costs were \$1.1 million after-tax proceeds from an earlier sale of development rights in a power plant project. This represented the first of two payments that were contingent upon certain agreed-upon terms for construction progress occurring.

### **Critical Accounting Policies**

There have been no material changes in our critical accounting policies from those reported in our 2007 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 2007 Annual Report on Form 10-K.

### **Liquidity and Capital Resources**

#### **Cash Flow Activities**

During the three month period ended March 31, 2008, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on our common stock, to pay our scheduled long-term debt maturities and to fund a portion of our property, plant and equipment additions. We plan to fund future property and investment additions including our pending acquisition of certain electric and gas utility assets of Aquila and the construction costs of the 100 MW Wygen III generation facility located near Gillette, Wyoming from internally generated cash resources including proceeds from the pending sale of certain IPP assets and from a combination of external financings.

Cash flows from operations of \$53.7 million represent a \$39.0 million decrease for the three month period ended March 31, 2008 compared to the same period in the prior year due to a \$15.9 million decrease in income from continuing operations and from the following:

- A \$59.5 million decrease in cash flows from working capital changes. This decrease primarily resulted from changes in net accounts receivable and accounts payable offset by a \$10.5 million increase in cash flows from a net sale of materials, supplies and fuel. This is primarily related to natural gas held in storage by our natural gas and crude oil marketing business which fluctuates based on economic decisions reflecting current market conditions;
- A \$28.7 million increase in cash flows from the net change in derivative assets and liabilities, primarily from derivatives associated with normal operations of our gas and oil marketing business and related commodity price fluctuations;
- A \$5.0 million decrease in cash flows related to changes in deferred income taxes which is primarily the result of accelerated deductions relating to property, plant and equipment, intangible drilling costs related to our Oil and gas segment and changes in derivative assets and liabilities; and
- A \$2.5 million increase in depreciation, depletion and amortization.

During the three months ended March 31, 2008, we had cash outflows from investing activities of \$80.6 million, which were primarily due to the following:

- Cash outflows of \$74.3 million for property, plant and equipment additions. In addition to expenditures for property, plant and equipment in the normal course of business, these outflows include approximately \$20.0 million related to the construction of our Wygen III power plant, approximately \$12.1 million in oil and gas property maintenance capital and development drilling, and \$17.6 million related to the construction of the Valencia power plant; and
- Cash outflows of \$7.3 million for short-term investments.

During the three months ended March 31, 2008, we had net cash inflow from financing activities of \$21.8 million, primarily due to:

- \$36.0 million net borrowings of funds from our credit facility; partially offset by:
- The payment of cash dividends on common stock.

### **Dividends**

Dividends paid on our common stock totaled \$13.3 million during the three months ended March 31, 2008, or \$0.35 per share. At its April 28, 2008 meeting, our Board of Directors declared a quarterly dividend payable June 1, 2008 of \$0.35 per share, equivalent to an annual dividend rate of \$1.40 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 facility and our future business prospects.

### **Financing Transactions and Short-Term Liquidity**

Our principal sources of short-term liquidity are our revolving credit facility and cash provided by operations. Our liquidity position remained strong during the first three months of 2008. As of March 31, 2008, we had approximately \$75.6 million of cash unrestricted for operations. Approximately \$2.8 million of the March 31, 2008 cash balance was restricted by subsidiary debt agreements that limit our subsidiaries' ability to dividend cash to the parent company.

Our \$400 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 0.70 basis points over LIBOR (which equates to a 3.4 percent one-month borrowing rate as of March 31, 2008).

Our revolving credit facility can be used to fund our working capital needs and for general corporate purposes. At March 31, 2008, we had borrowings of \$73.0 million and \$49.4 million of letters of credit issued. Available capacity remaining on our revolving credit facility was approximately \$277.6 million at March 31, 2008.

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 percent of our aggregate consolidated net income beginning January 1, 2005;
- a recourse leverage ratio not to exceed 0.65 to 1.00, (or 0.70 to 1.00 for the first year after the Aquila acquisition); 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.

A default under the credit facility may be triggered by events such as a failure to comply with financial covenants or certain other covenants under the credit facility, 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. A default under the credit facility would permit the participating banks to restrict our ability to further access the credit facility for loans or new letters of credit, require the immediate repayment of any outstanding loans with interest and require 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 \$965.2 million at March 31, 2008, which was approximately \$225.2 million in excess of the net worth we were required to maintain under the credit facility. Our long-term debt ratio at March 31, 2008 was 36.8 percent, our total debt leverage (long-term debt and short-term debt) was 44.6 percent, our recourse leverage ratio was approximately 45.8 percent and our interest expense coverage ratio for the twelve month period ended March 31, 2008 was 5.2 to 1.0.

In addition, Enserco, our energy marketing segment, has a \$300 million uncommitted, discretionary line of credit to provide support for the purchase and sale of natural gas and crude oil. The line of credit is secured by all of Enserco's assets. At March 31, 2008, there were outstanding letters of credit issued under the facility of \$170.2 million, with no borrowing balances outstanding on the facility. This credit facility was recently renewed for another year, extending the expiration to May 8, 2009.

Our corporate credit rating by Moody's was "Baa3" during the first three months of 2008; the outlook is negative. Our corporate credit rating by S&P was "BBB-;" the outlook is stable.

On May 7, 2007, we entered into a senior unsecured \$1.0 billion Acquisition Facility with ABN AMRO Bank N.V. as administrative agent and other banks to provide for funding for our pending acquisition of Aquila's electric utility in Colorado and its gas utilities in Colorado, Kansas, Nebraska and Iowa. The Acquisition Facility is a committed facility to fund an acquisition term loan in a single draw in an amount of up to \$1.0 billion. The commitment to fund the acquisition term loan terminates on August 5, 2008. Upon funding of the loan, the loan termination date is February 5, 2009.

The Acquisition Facility includes conditions precedent to funding which include consummation of the Aquila acquisition substantially in accordance with the existing asset purchase agreement. Borrowings under the term loan can be made 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 applicable margin for LIBOR borrowings is 55 basis points during the period from the initial funding under the term loan to six months thereafter, 67.5 basis points during the period from six months and one day after the initial funding to nine months thereafter, and 92.5 basis points during the period from nine months and one day after the initial funding until the loan maturity. The facility also includes certain customary affirmative and negative covenants which largely replicate the covenants under our existing revolving credit facility.

We plan to fund future property and investment additions including our pending acquisition of certain electric and gas utility assets of Aquila and the construction costs of the 100 MW Wygen III generation facility located near Gillette, Wyoming from internally generated cash resources including proceeds from the pending sale of certain IPP assets and from a combination of external financings. Our Wygen I project debt of \$128.3 million matures in June 2008. We initially intend to refinance this indebtedness through borrowings on the revolving credit facility until permanent financing is complete.

Our ability to obtain additional financing, if necessary, will depend upon a number of factors, including our future performance and financial results, and capital market conditions. We can provide no assurance that we will be able to raise additional capital on reasonable terms or at all.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2007 Annual Report on Form 10-K filed with the SEC.

### **Capital Requirements**

During the three months ended March 31, 2008, capital expenditures were approximately \$74.1 million for property, plant and equipment additions, which were partially financed through approximately \$25.5 million of accrued liabilities. We currently expect total capital expenditures, excluding the Aquila asset acquisition, for 2008 to approximate \$298.7 million, including \$40.7 million related to the Valencia 149 MW, simple-cycle gas turbine generating facility located near Albuquerque, New Mexico, \$57.8 million for the 100 MW Wygen III power plant located near Gillette, Wyoming (with the assumption we retain 55 percent ownership in the plant), and \$94.2 million within our Oil and gas segment primarily for maintenance capital and development drilling.

We continue to actively evaluate potential future acquisitions and other growth opportunities in accordance with our disclosed business strategy. We are not obligated to a project until a definitive agreement is entered into and cannot guarantee we will be successful in acquiring or developing any potential projects. Future projects are dependent upon the availability of attractive economic opportunities and, as a result, actual expenditures may vary significantly from forecasted estimates.

### **New Accounting Pronouncements**

Other than the new pronouncements reported in our 2007 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 issued that when implemented would require us to either retroactively restate prior period financial statements or record a cumulative catch-up adjustment.

## SAFE HARBOR FOR FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q includes “forward-looking statements” as defined by the SEC. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this Form 10-Q that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties that, among other things, could cause actual results to differ materially from those contained in the forward-looking statements, including the risk factors described in Item 1A. of Part I of our 2007 Annual Report on Form 10-K, our other report and filings with the SEC, and the following:

- Our ability to obtain adequate cost recovery for our retail utility operations through regulatory proceedings; to receive favorable rulings in periodic applications to recover costs for fuel and purchased power in our regulated utilities; and our ability to add power generation assets into our regulatory rate base;
- Our ability to complete acquisitions or dispositions for which definitive agreements have been executed;
- Our ability to obtain regulatory approval of acquisitions or dispositions which, even if approved, could impose financial and operating conditions or restrictions that could impact our expected results;
- Our ability to successfully integrate and profitably operate any future acquisitions;
- The amount and timing of capital deployment in new investment opportunities or for the repurchase of debt or stock;
- Our ability to obtain beneficial income tax treatment to defer gains associated with asset dispositions;
- Our ability to successfully maintain or improve our corporate credit rating;
- Our ability to obtain from utility commissions any requisite determination of prudence to support resource planning and development programs we propose to implement;
- Our ability to complete the planning, permitting, construction, start up and operation of power generating facilities in a cost-effective and timely manner;
- Our ability to meet production targets for our oil and gas properties, which may be dependent upon issuance by federal, state, and tribal governments, or agencies thereof, of drilling, environmental and other permits, and the availability and cost of specialized contractors, work force, and equipment;
- Our ability to provide accurate estimates of proved oil and gas reserves, coal reserves and actual future production rates and associated costs;
- The extent of our success in connecting natural gas supplies to gathering, processing and pipeline systems;

- The timing and extent of scheduled and unscheduled outages of power generation facilities;
- The possibility that we may be required to take impairment charges to reduce the carrying value of some of our long-lived assets when indicators of impairment emerge;
- Changes in business and financial reporting practices arising from the enactment of the Energy Policy Act of 2005;
- Our ability to remedy any deficiencies that may be identified in the review of our internal controls;
- The timing, volatility and extent of changes in energy-related and commodity prices, interest rates, foreign exchange rates, energy and commodity supply or volume, the cost and availability of transportation of commodities, and demand for our services, all of which can affect our earnings, liquidity position and the underlying value of our assets;
- Our ability to effectively use derivative financial instruments to hedge commodity, currency exchange rate and interest rate risks;
- Our ability to minimize defaults on amounts due from counterparties with respect to trading and other transactions;
- The amount of collateral required to be posted from time to time in our transactions;
- Changes in or compliance with laws and regulations, particularly those relating to taxation, safety and protection of the environment;
- Changes in state laws or regulations that could cause us to curtail our IPP operations;
- Weather and other natural phenomena;
- Industry and market changes, including the impact of consolidations and changes in competition;
- The effect of accounting policies issued periodically by accounting standard-setting bodies;
- The cost and effects on our business, including insurance, resulting from terrorist actions or responses to such actions or events;
- The outcome of any ongoing or future litigation or similar disputes and the impact on any such outcome or related settlements;
- Capital market conditions and market uncertainties related to interest rates, which may affect our ability to raise capital on favorable terms;
- Price risk due to marketable securities held as investments in benefit plans;
- General economic and political conditions, including tax rates or policies and inflation rates; and
- Other factors discussed from time to time in our other filings with the SEC.

New factors that could cause actual results to differ materially from those described in forward-looking statements emerge from time to time, and it is not possible for us to predict all such factors, or the extent to which any such factor or combination of factors may cause actual results to differ from those contained in any forward-looking statement. We assume no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events, or otherwise.

### ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

#### 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, 2008 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2007	\$ 3,718 <sup>(a)</sup>
Net cash settled during the period on positions that existed at December 31, 2007	(960)
Change in fair value due to change in assumptions	1,898
Unrealized gain on new positions entered during the period and still existing at March 31, 2008	535
Realized gain on positions that existed at December 31, 2007 and were settled during the period	89
Change in cash collateral <sup>(b)</sup>	34,163
Unrealized loss on positions that existed at December 31, 2007 and still exist at March 31, 2008	<u>(10,491)</u>
Total fair value of energy marketing positions at March 31, 2008	<u>\$ 28,952<sup>(a)</sup></u>

(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, <u>2008</u>	December 31, <u>2007</u>
Net derivative (liabilities) assets	\$ (8,475)	\$ 14,797
Cash collateral	32,876	(1,287)
Market adjustment recorded in material, supplies and fuel	<u>4,551</u>	<u>(9,792)</u>
	<u>\$ 28,952</u>	<u>\$ 3,718</u>

(b) The Company adopted FSP FIN 39-1 effective January 1, 2008. See Note 2 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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 and our expected cash flows from energy trading activities. At 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.

We adopted the provisions of SFAS 157 on January 1, 2008. SFAS 157 provides a single definition of fair value and establishes a fair value hierarchy which requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. We use the fair value methodology outlined in SFAS 157 to value the assets and liabilities for our outstanding derivative contracts. See Note 12 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

<u>Source of Fair Value</u>	<u>Maturities</u>		<u>Total Fair Value</u>
	<u>Less than 1 year</u>	<u>1 – 2 years</u>	
Level 1	\$ 32,876	\$ —	\$ 32,876
Level 2	(8,158)	445	(7,713)
Level 3	(567)	(195)	(762)
Market value adjustment for inventory (see footnote (a) above)	4,551	—	4,551
<b>Total</b>	<b>\$ 28,702</b>	<b>\$ 250</b>	<b>\$ 28,952</b>

The following table presents a reconciliation of our March 31, 2008 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)	\$ 28,952
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	<u>42,671</u>
Fair value of all forward positions (non-GAAP)	71,623
Cash collateral included in GAAP marked-to-market fair value	<u>(32,876)</u>
Fair value of all forward positions excluding cash collateral (non-GAAP)	<u>\$ 38,747</u>

There have been no material changes in market risk faced by us from those reported in our 2007 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 2007 Annual Report on Form 10-K, and Note 11 of our Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

### Activities Other Than Trading

The Company has entered into agreements to hedge a portion of its estimated 2008, 2009 and 2010 natural gas and crude oil production. The hedge agreements in place are as follows:

#### Natural Gas

<u>Location</u>	<u>Transaction Date</u>	<u>Hedge Type</u>	<u>Term</u>	<u>Volume</u> (MMBtu/day)	<u>Price</u>
San Juan El Paso	11/29/2006	Swap	01/08 – 12/08	5,000	\$ 7.44
San Juan El Paso	11/29/2006	Swap	11/07 – 12/08	3,000	\$ 7.49
San Juan El Paso	01/04/2007	Swap	04/08 – 03/09	2,500	\$ 6.93
San Juan El Paso	01/04/2007	Swap	04/08 – 03/09	1,000	\$ 6.96
San Juan El Paso	01/05/2007	Swap	01/09 – 03/09	1,500	\$ 7.51
San Juan El Paso	01/10/2007	Swap	04/08 – 12/08	1,500	\$ 6.88
San Juan El Paso	01/11/2007	Swap	04/08 – 12/08	2,000	\$ 6.81
San Juan El Paso	02/12/2007	Swap	01/09 – 03/09	5,000	\$ 7.87
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
CIG	05/09/2007	Swap	01/09 – 03/09	2,000	\$ 8.37
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
CIG	09/07/2007	Swap	04/08 – 12/08	1,500	\$ 5.91
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 Basis	11/16/2007	Swap	04/08 – 12/08	-1,500	\$ (0.93)
NWR Basis	11/16/2007	Swap	04/08 – 12/08	1,500	\$ (1.64)
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
AECO	01/23/2008	Swap	04/08 – 12/08	1,000	\$ 6.87
San Juan El Paso	02/28/2008	Swap	01/10 – 03/10	3,000	\$ 8.55
AECO	02/28/2008	Swap	04/08 – 10/08	1,000	\$ 8.37
CIG	02/28/2008	Swap	04/08 – 10/08	1,000	\$ 7.73
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

## Crude Oil

<u>Location</u>	<u>Transaction Date</u>	<u>Hedge Type</u>	<u>Term</u>	<u>Volume</u> (Bbls/month)	<u>Price</u>
NYMEX	01/30/2007	Swap	Calendar 2008	5,000	\$ 61.38
NYMEX	02/20/2007	Put	Calendar 2008	5,000	\$ 60.00
NYMEX	03/07/2007	Swap	Calendar 2008	5,000	\$ 67.34
NYMEX	03/23/2007	Swap	01/09 – 03/09	5,000	\$ 67.60
NYMEX	03/26/2007	Put	Calendar 2008	5,000	\$ 63.00
NYMEX	03/28/2007	Swap	01/09 – 03/09	5,000	\$ 69.00
NYMEX	04/12/2007	Put	01/09 – 03/09	5,000	\$ 65.00
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	01/09 – 03/09	5,000	\$ 70.00
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	04/08 – 06/08	5,000	\$ 75.00
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

#### **ITEM 4. CONTROLS AND PROCEDURES**

Our Chief Executive Officer, who is also currently serving as interim 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, 2008. Based on his evaluation, he has concluded that our disclosure controls and procedures are effective.

There were no changes in our internal control over financial reporting during the quarter ended March 31, 2008 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II – Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 18 in Item 8 of our 2007 Annual Report on Form 10-K and Note 13 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 13 is incorporated by reference into this item.

Item 1A. Risk Factors

There have been no material changes in our Risk Factors from those reported in Item 1A. of Part I of our Annual Report on Form 10-K for the year ended December 31, 2007.

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

**Issuer Purchases of Equity Securities**

<u>Period</u>	<u>Total Number of Shares Purchased</u>	<u>Average Price Paid per Share</u>	<u>Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs</u>	<u>Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs</u>
January 1, 2008 – January 31, 2008	11,692 <sup>(1)</sup>	\$ 41.95	—	—
February 1, 2008 – February 29, 2008	938 <sup>(1)</sup>	\$ 40.18	—	—
March 1, 2008 – March 31, 2008	729 <sup>(1)</sup>	\$ 36.04	—	—
<b>Total</b>	<b>13,359</b>	<b>\$ 41.50</b>	<b>—</b>	<b>—</b>

(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 exercise of stock options.

Item 5. Other Information

**Entry into a Material Definitive Agreement**

On May 8, 2008, the Registrant's subsidiary, Enserco Energy Inc. ("Enserco"), entered into a Fourth Amendment to the Second Amended and Restated Credit Agreement dated as of June 1, 2006, by and among Enserco, Fortis Capital Corp., as Administrative Agent, Documentation Agent and Collateral Agent, BNP Paribas, U.S. Bank National Association, Societe Generale and The Bank of Tokyo-Mitsubishi UFJ, Ltd, New York Branch. The Fourth Amendment extended the term of the facility to May 8, 2009.

Item 6. Exhibits

- Exhibit 10.1 Severance and Release Agreement between Black Hills Corporation and Mark T. Thies dated January 18, 2008 (filed as Exhibit 10 to the Company's Form 8-K filed on January 18, 2008 and incorporated by reference herein).
- Exhibit 10.2 Mutual Notice of Extension provided as of January 31, 2008, by and among Black Hills Corporation, Aquila, Inc. and Great Plains Energy Incorporated (filed as Exhibit 10 to the Company's Form 8-K filed on February 1, 2008 and incorporated by reference herein).
- Exhibit 10.3 Fourth Amendment to the Second Amended and Restated Credit Agreement effective May 8, 2008, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, documentation agent and collateral agent, BNP Paribas, U.S. Bank National Association, Societe Generale, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch.
- Exhibit 10.4 Third Amendment to the Second Amended and Restated Credit Agreement effective March 5, 2008, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, documentation agent and collateral agent, BNP Paribas, U.S. Bank National Association, Societe Generale, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch.
- Exhibit 31 Certification pursuant to Rule 13a – 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes – Oxley Act of 2002.
- Exhibit 32 Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes – Oxley Act of 2002.

BLACK HILLS CORPORATION

Signatures

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

BLACK HILLS CORPORATION

/s/ David R. Emery

David R. Emery, Chairman, President and  
Chief Executive Officer  
and interim Principal Financial Officer

Dated: May 9, 2008

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