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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2008.

OR

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

Commission File Number 001-31303

Black Hills Corporation

Incorporated in South Dakota — IRS Identification Number 46-0458824

625 Ninth Street
Rapid City, South Dakota 57701

Registrant’s telephone number (605) 721-1700

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No o

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

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

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

Yes o No x

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

Class	Outstanding at July 31, 2008
Common stock, $1.00 par value	38,405,259 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 Non-regulated Holdings, LLC
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of the Company, formerly Black Hills Energy, Inc.
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Btu	British thermal unit
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
CT	Combustion turbine
Dth	Dekatherm
Enserco	Enserco Energy Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, LLC
FASB	Financial Accounting Standards Board
FSP	FASB Staff Position
FSP FAS 157-1	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	FSP FAS 157-2, "Effective Date of FASB Statement No. 157"
FSP FIN 39-1	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
Las Vegas II	Las Vegas II gas-fired power plant
LVC	Las Vegas Cogeneration Limited Partnership, an indirect, wholly-owned subsidiary of Black Hills Non-regulated Holdings, LLC, recently sold as part of our July 11, 2008 IPP asset sale
Mcf	One thousand cubic feet
Mcfe	One thousand cubic feet equivalent

MDU	MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MMBtu	One million British thermal units
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 or Disposal 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 Non-regulated Holdings, LLC, recently sold as part of our July 11, 2008 IPP asset sale
VIE	Variable Interest Entity
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, LLC

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(in thousands, except per share amounts)			
Operating revenues	$ 153,273	$ 133,526	$ 306,123	$ 291,023
Operating expenses:				
Fuel and purchased power	46,948	33,095	99,343	80,417
Operations and maintenance	24,320	16,557	46,285	33,062
Administrative and general	25,222	25,381	49,281	50,318
Depreciation, depletion and amortization	20,788	17,618	40,174	34,315
Taxes, other than income taxes	10,472	9,049	19,980	17,578
	127,750	101,700	255,063	215,690
Operating income	25,523	31,826	51,060	75,333
Other income (expense):				
Interest expense	(9,564)	(5,520)	(18,758)	(11,778)
Interest income	373	692	799	1,416
Allowance for funds used during construction – equity	617	1,206	898	3,040
Other income, net	65	(10)	400	325
	(8,509)	(3,632)	(16,661)	(6,997)
Income from continuing operations before equity in earnings of unconsolidated subsidiaries, minority interest and income taxes	17,014	28,194	34,399	68,336
Equity in earnings of unconsolidated subsidiaries	2,064	673	2,297	1,518
Minority interest	(53)	(95)	(130)	(188)
Income tax expense	(5,875)	(9,293)	(11,676)	(22,515)
Income from continuing operations	13,150	19,479	24,890	47,151
Income from discontinued operations, net of taxes	9,046	5,619	14,098	10,400
Net income	$ 22,196	$ 25,098	$ 38,988	$ 57,551
Weighted average common shares outstanding:				
Basic	38,299	37,588	38,062	36,387
Diluted	38,425	38,007	38,412	36,793
Earnings per share:				
Basic–				
Continuing operations	$ 0.34	$ 0.52	$ 0.65	$ 1.29
Discontinued operations	0.24	0.15	0.37	0.29
Total	$ 0.58	$ 0.67	$ 1.02	$ 1.58
Diluted–				
Continuing operations	$ 0.34	$ 0.51	$ 0.65	$ 1.28
Discontinued operations	0.24	0.15	0.36	0.28
Total	$ 0.58	$ 0.66	$ 1.01	$ 1.56
Dividends paid per share of common stock	$ 0.35	$ 0.34	$ 0.70	$ 0.68

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)

	June 30, 2008	December 31, 2007*	June 30, 2007*
	(in thousands, except share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 36,912	$ 76,889	$ 35,685
Restricted cash	5,498	5,443	5,341
Short-term investments	7,309	—	—
Receivables (net of allowance for doubtful accounts of $3,417; $4,588 and $4,735, respectively)	252,508	268,462	244,284
Materials, supplies and fuel	147,169	88,580	125,484
Derivative assets	70,769	35,921	55,591
Deferred income taxes	20,674	4,512	—
Other assets	15,685	12,698	8,200
Assets of discontinued operations	598,294	573,601	564,786
	1,154,818	1,066,106	1,039,371
Investments	18,782	19,216	23,506
Property, plant and equipment	1,972,489	1,846,565	1,759,704
Less accumulated depreciation and depletion	(544,018)	(509,187)	(490,104)
	1,428,471	1,337,378	1,269,600
Other assets:			
Derivative assets	14,042	2,492	5,351
Goodwill	14,000	11,482	12,170
Other	32,121	32,960	52,903
	60,163	46,934	70,424
	$ 2,662,234	$ 2,469,634	$ 2,402,901
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$ 269,095	$ 239,177	$ 229,464
Accrued liabilities	90,964	100,986	82,187
Derivative liabilities	89,790	39,380	17,069
Deferred income taxes	—	—	4,769
Notes payable	283,000	37,000	84,000
Current maturities of long-term debt	2,070	130,326	130,519
Accrued income taxes	4,601	833	30,306
Liabilities of discontinued operations	77,202	91,233	119,612
	816,722	638,935	697,926
Long-term debt, net of current maturities	501,301	503,301	401,894
Deferred credits and other liabilities:			
Deferred income taxes	218,104	207,735	192,492
Derivative liabilities	23,158	9,375	2,707
Other	134,232	135,266	132,757
	375,494	352,376	327,956
Minority interest in subsidiaries	132	5,167	4,978
Stockholders' equity:			
Common stock equity –			
Common stock $1 par value; 100,000,000 shares authorized; Issued 38,439,339; 37,842,221 and 37,768,792 shares, respectively	38,439	37,842	37,769
Additional paid-in capital	579,725	560,475	556,981
Retained earnings	409,651	397,393	382,254
Treasury stock at cost – 31,604; 45,916 and 42,209 shares, respectively	(1,132)	(1,347)	(1,189)
Accumulated other comprehensive loss	(58,098)	(24,508)	(5,668)
	968,585	969,855	970,147
	$ 2,662,234	$ 2,469,634	$ 2,402,901

* 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)

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007*
	(in thousands)	
Operating activities:		
Net income	$ 38,988	$ 57,551
Income from discontinued operations, net of taxes	(14,098)	(10,400)
Income from continuing operations	24,890	47,151
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	40,174	34,315
Net change in derivative assets and liabilities	(515)	(15,260)
Deferred income taxes	14,827	8,052
(Undistributed) distributed earnings in associated companies	(655)	500
Allowance for funds used during construction – equity	(898)	(3,040)
Change in operating assets and liabilities:		
Materials, supplies and fuel	(42,490)	(14,963)
Accounts receivable and other current assets	(32,520)	(15,647)
Accounts payable and other current liabilities	22,963	15,176
Other operating activities	(7,629)	11,629
Net cash provided by operating activities of continuing operations	18,147	67,913
Net cash provided by operating activities of discontinued operations	23,113	17,232
Net cash provided by operating activities	41,260	85,145
Investing activities:		
Property, plant and equipment additions	(127,036)	(97,337)
Increase in short-term investments	(7,475)	—
Other investing activities	994	(3,535)
Net cash used in investing activities of continuing operations	(133,517)	(100,872)
Net cash used in investing activities of discontinued operations	(33,375)	(11,317)
Net cash used in investing activities	(166,892)	(112,189)
Financing activities:		
Dividends paid	(26,730)	(24,218)
Common stock issued	2,384	148,663
Increase (decrease) in short-term borrowings, net	246,000	(61,500)
Long-term debt – repayments	(130,256)	(26,247)
Other financing activities	215	(555)
Net cash provided by financing activities of continuing operations	91,613	36,143
Net cash used in financing activities of discontinued operations	(6,428)	(6,429)
Net cash provided by financing activities	85,185	29,714
(Decrease) increase in cash and cash equivalents	(40,447)	2,670
Cash and cash equivalents:		
Beginning of period	81,255(b)	37,530(d)
End of period	$ 40,808(a)	$ 40,200(c)
Supplemental disclosure of cash flow information:		
Non-cash investing and financing activities-		
Property, plant and equipment acquired with accrued liabilities	$ 20,053	$ 22,571
Cash paid during the period for-		
Interest (net of amounts capitalized)	$ 18,665	$ 20,229
Income taxes paid (net of amounts refunded)	$ 2,293	$ 7,483

* As adjusted (see Note 2)

(a) Includes approximately $3.9 million of cash included in the assets of discontinued operations.
(b) Includes approximately $4.4 million of cash included in the assets of discontinued operations.
(c) Includes approximately $4.5 million of cash included in the assets of discontinued operations.
(d) Includes approximately $5.0 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.

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 June 30, 2008, December 31, 2007 and June 30, 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 six months ended June 30, 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 Operating revenues on the accompanying Condensed Consolidated Statements of Income. SFAS 157 also requires new disclosures regarding the level of pricing observability associated with instruments carried at fair value. This additional disclosure is provided in Note 12.

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 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.

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 June 30**,** 2007 amounts have been reclassified to conform to this presentation as follows (in thousands):

Balance Sheet Line Description	As Reported for the 2007 10-K	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	As Reported for the June 2008 10-Q
Current assets:				
Receivables	$ 291,189	$ (1,945)	$ (20,782)	$ 268,462
Derivative assets	$ 37,208	$ (1,287)	$ —	$ 35,921
Current liabilities:				
Accounts payable	$ 242,813	$ (3,232)	$ (404)	$ 239,177

Balance Sheet Line Description	As Reported for the June 2007 10-Q	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	As Reported for the June 2008 10-Q
Current assets:				
Receivables	$ 277,552	$ (15,453)	$ (17,815)	$ 244,284
Derivative assets	$ 40,138	$ 15,453	$ —	$ 55,591
Non-current assets:				
Derivative assets	$ 5,413	$ (62)	$ —	$ 5,351
Non-current liabilities:				
Derivative liabilities	$ 2,769	$ (62)	$ —	$ 2,707

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

Cash Flow Statement Operating Activities Line Description	As Reported for the June 2007 10-Q	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	As Reported for the June 2008 10-Q
Net change in derivative assets and liabilities	$ (12,382)	$ (2,878)	$ —	$ (15,260)
Accounts payable and other current liabilities	$ 11,645	$ 2,878	$ (9,263)	$ 5,260

As of June 30, 2008, December 31, 2007 and June 30, 2007, the Company offset fair value cash collateral receivables and payables against net derivative positions in the amounts of $47.8 million, $(1.3) million and $15.5 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. We expect SFAS 141(R) will have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of any acquisitions we consummate after the effective date. If income tax liabilities are settled for an amount other than as previously recorded prior to the adoption of SFAS 141(R), the reversal of any remaining liability will affect goodwill. If such liabilities reverse subsequent to the adoption of SFAS 141(R), such reversals will affect expense including income tax expense in the period of reversal. The Company is assessing the full impact SFAS 141(R) would have on future 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):

Major Classification	June 30, 2008	December 31, 2007	June 30, 2007
Materials and supplies	$ 28,350	$ 27,649	$ 27,565
Fuel	6,098	5,025	6,444
Gas and oil held by Energy marketing*	112,721	55,906	91,475
Total materials, supplies and fuel	$ 147,169	$ 88,580	$ 125,484

* As of June 30, 2008, December 31, 2007 and June 30, 2007, market adjustments related to natural gas held by Energy marketing and recorded in inventory were $6.3 million, $(9.8) million and $(6.4) 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) NOTES PAYABLE AND LONG-TERM DEBT

During June 2008, the Company repaid the $128.3 million Wygen I project debt. Borrowings on the revolving credit facility were used to fund the repayment.

We had previously been the lessee of the Wygen I Plant under a synthetic lease arrangement and under GAAP we consolidated the plant, the related project debt and all its operating and financial activities into our financial statements. In conjunction with the repayment of the project debt, the synthetic lease structure was terminated and the Company assumed direct ownership of the plant. Since the plant and its financial activities were previously consolidated into our financial statements, the transaction had minimal impact on our consolidated financial statements.

(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):

Period ended June 30, 2008	Three Months		Six Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 13,150		$ 24,890	
Basic earnings	13,150	38,299	24,890	38,062
Dilutive effect of:				
Stock options	—	62	—	71
Estimated contingent shares issuable for prior acquisition	—	—	—	198
Others	—	64	—	81
Diluted earnings	$ 13,150	38,425	$ 24,890	38,412

Period ended June 30, 2007	Three Months		Six Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 19,479		$ 47,151	
Basic earnings	19,479	37,588	47,151	36,387
Dilutive effect of:				
Stock options	—	112	—	107
Estimated contingent shares issuable for prior acquisition	—	159	—	159
Others	—	148	—	140
Diluted earnings	$ 19,479	38,007	$ 47,151	36,793

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 June 30, 2008	Three Months Ended June 30, 2007
Net income	$ 22,196	$ 25,098
Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $5,510 and $(5,686), respectively)	(10,359)	10,087
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $(2,261) and $2,700, respectively)	4,037	(4,798)
Unrealized loss on available for sale securities (net of tax of $(7))	12	—
Total comprehensive income	$ 15,886	$ 30,387

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Net income	$ 38,988	$ 57,551
Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $20,462 and $(1,794), respectively)	(37,792)	3,723
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $(2,413) and $4,372, respectively)	4,310	(8,876)
Unrealized loss on available for sale securities (net of tax of $58)	(108)	—
Total comprehensive income	$ 5,398	$ 52,398

Other comprehensive loss on fair value adjustments on derivatives designated as cash flow hedges in the six months ended June 30, 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 June 30, 2008	$ (51,709)	$ (6,115)	$ (166)	$ (108)	$ (58,098)
As of December 31, 2007	$ (18,178)	$ (6,115)	$ (215)	$ —	$ (24,508)
As of June 30, 2007	$ 2,892	$ (8,404)	$ (156)	$ —	$ (5,668)

(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 six months ended June 30, 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 six months ended June 30, 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.

- 84,880 stock options were exercised during the six months ended June 30, 2008, at a weighted-average exercise price of $24.90 per share providing $2.1 million of proceeds to the Company.

- Total compensation expense recognized for all equity compensation plans for the three months ended June 30, 2008 and 2007 was $0.5 million and $2.0 million, respectively, and for the six months ended June 30, 2008 and 2007 was $0.7 million and $3.0 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 June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Service cost	$ 754	$ 687	$ 1,508	$ 1,374
Interest cost	1,230	1,129	2,460	2,258
Expected return on plan assets	(1,573)	(1,374)	(3,146)	(2,748)
Prior service cost	41	38	82	76
Net loss	—	127	—	254
Net periodic benefit cost	$ 452	$ 607	$ 904	$ 1,214

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 June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Service cost	$ 112	$ 103	$ 224	$ 206
Interest cost	311	289	622	578
Prior service cost	3	3	6	6
Net loss	142	178	284	356
Net periodic benefit cost	$ 568	$ 573	$ 1,136	$ 1,146

The Company anticipates that it will 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 June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Service cost	$ 125	$ 135	$ 250	$ 270
Interest cost	217	207	434	414
Net transition obligation	15	15	30	30
Net gain	(20)	(4)	(40)	(8)
Net periodic benefit cost	$ 337	$ 353	$ 674	$ 706

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 and six month periods ended June 30, 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 June 30, 2008, substantially all of the Company's operations and assets are located within the United States. On July 11, 2008, the Company sold seven of its IPP assets with a total capacity of 974 megawatts. The financial information related to these plants was previously reported in the Power generation segment and has been reclassified to discontinued operations.

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. Subsequent to the July 11, 2008 sale of seven IPP plants, the segment assets include power plants located in Wyoming, California and Idaho;

- 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 regulated utilities are not eliminated.

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

Three Month Period Ended June 30, 2008	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric utility	$ 57,615	$ 363	$ 5,251
Electric and gas utility	35,952	—	4,302
Non-regulated energy:			
Oil and gas	34,209	—	7,197
Power generation	2,135	6,376	(525)
Coal mining	7,987	4,660	496
Energy marketing	5,150	—	365
Corporate	—	—	(3,897)
Inter-segment eliminations	—	(1,174)	(39)
Total	$ 143,048	$ 10,225	$ 13,150

Three Month Period Ended June 30, 2007	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric utility	$ 44,387	$ 585	$ 4,881
Electric and gas utility	21,652	—	1,043
Non-regulated energy:			
Oil and gas	25,814	—	4,376
Power generation	9,545	—	(319)
Coal mining	6,424	3,578	1,379
Energy marketing	22,909	—	8,938
Corporate	—	—	(819)
Inter-segment eliminations	—	(1,368)	—
Total	$ 130,731	$ 2,795	$ 19,479

Six Month Period Ended June 30, 2008	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric utility	$ 114,940	$ 670	$ 10,827
Electric and gas utility	77,928	—	8,893
Non-regulated energy:			
Oil and gas	60,331	—	9,749
Power generation	4,449	12,926	(1,498)
Coal mining	15,876	10,018	2,124
Energy marketing	11,269	—	664
Corporate	—	—	(5,830)
Inter-segment eliminations	—	(2,284)	(39)
Total	$ 284,793	$ 21,330	$ 24,890

Six Month Period Ended June 30, 2007	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric utility	$ 91,743	$ 996	$ 11,580
Electric and gas utility	58,015	—	4,115
Non-regulated energy:			
Oil and gas	51,657	—	7,967
Power generation	20,075	—	(169)
Coal mining	12,641	7,106	2,995
Energy marketing	51,347	—	21,596
Corporate	1	—	(933)
Inter-segment eliminations	—	(2,558)	—
Total	$ 285,479	$ 5,544	$ 47,151

During 2008, the Company added assets of approximately $49.6 million on the ongoing construction of the Wygen III power plant within the Electric utility segment and approximately $13.6 million for 2008 capitalized development costs related to the Aquila asset acquisition, consisting of $4.6 million for professional fees and $9.0 million in hardware and software costs. Other than these significant additions and the reclassification to discontinued operations of the IPP assets sold, 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:

	Outstanding at June 30, 2008		Outstanding at December 31, 2007		Outstanding at June 30, 2007	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of MMBtus)						
Natural gas basis swaps purchased	209,344	40	125,577	36	179,020	18
Natural gas basis swaps sold	212,498	40	128,892	36	195,952	18
Natural gas fixed for float swaps purchased	50,707	24	42,326	24	33,520	24
Natural gas fixed for float swaps sold	65,093	24	59,253	24	59,401	24
Natural gas physical purchases	130,253	22	90,583	15	81,261	18
Natural gas physical sales	168,938	22	98,888	27	108,359	28
Natural gas options purchased	7,650	9	3,472	10	9,266	9
Natural gas options sold	7,650	9	3,472	10	8,832	9

	Outstanding at June 30, 2008		Outstanding at December 31, 2007		Outstanding at June 30, 2007	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of Bbls)						
Crude oil physical purchases	6,713	18	4,991	12	2,178	4
Crude oil physical sales	5,084	18	3,800	12	2,092	5
Crude oil swaps/options purchased	515	6	495	12	465	15
Crude oil swaps/options sold	565	6	495	12	465	15
(Dollars, in thousands)						
Canadian dollars purchased	$ 47,000	1	$ 28,000	2	$ 41,000	2
Canadian dollars sold	$ 6,000	1	$ —	—	$ —	—

Derivatives and certain natural gas and crude oil marketing activities were marked to fair value on June 30, 2008, December 31, 2007 and June 30, 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):

	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Cash Collateral Included in Derivative Assets/ Liabilities	Unrealized (Loss) Gain
June 30, 2008	$ 69,723	$ 14,010	$ 33,809	$ 2,480	$ (49,050)	$ (1,606)
December 31, 2007	$ 30,999	$ 1,901	$ 16,908	$ 2,482	$ 1,287	$ 14,797
June 30, 2007	$ 48,175	$ 122	$ 15,235	$ 408	$ (15,453)	$ 17,201

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 June 30, 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 June 30, 2008, December 31, 2007 and June 30, 2007, the market adjustments recorded in inventory were $6.3 million, $(9.8) million and $(6.4) million, respectively.

Activities Other Than Trading

Oil and Gas Exploration and Production

On June 30, 2008, December 31, 2007 and June 30, 2007, the Company had the following derivatives and related balances (in thousands):

	Notional*	Maximum Terms in Years	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax Income (Loss)
June 30, 2008								
Crude oil swaps/options	465,000	0.50	$ 389	$ —	$ 8,931	$ 5,996	$ (14,927)	$ 389
Natural gas swaps	10,474,000	1.34	702	26	25,363	11,040	(35,675)	—
			$ 1,091	$ 26	$ 34,294	$ 17,036	$ (50,602)	$ 389
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
			$ 4,684	$ 591	$ 4,013	$ 2,619	$ (1,713)	$ 356
June 30, 2007								
Crude oil swaps/options	465,000	1.00	$ 621	$ 17	$ 1,039	$ 542	$ (1,564)	$ 621
Natural gas swaps	11,247,000	1.17	6,411	296	664	1,757	4,714	(428)
			$ 7,032	$ 313	$ 1,703	$ 2,299	$ 3,150	$ 193

*crude in Bbls, gas in MMBtus

Based on June 30, 2008 market prices, a $34.0 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.

Financing Activities

On June 30, 2008, December 31, 2007 and June 30, 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
June 30, 2008								
Interest rate swaps	$ 150,000	5.04%	8.25	$ —	$ —	$ 2,760	$ 3,641	$ (6,401)
December 31, 2007								
Interest rate swaps	$ 150,000	5.04%	8.75	$ —	$ —	$ 1,792	$ 4,274	$ (6,066)
June 30, 2007								
Interest rate swaps	$ 150,000	5.04%	9.25	$ 384	$ 4,916	$ 55	$ —	$ 5,245

Based on June 30, 2008 market interest rates and balances, a loss of approximately $2.8 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

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 an amended mandatory early termination date of December 15, 2008. As of June 30, 2008, the mark-to-market value was $(18.9) 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 June 30, 2008. As required by SFAS 157, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. 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 June 30, 2008				
	Level 1	Level 2	Level 3	Counterparty Netting (a)	Total
Assets:					
Short-term investments	$ —	$ —	$ 7,309	$ —	$ 7,309
Commodity derivatives	49,050	291,848	24,424	(280,511)	84,811
Foreign currency derivative	—	318	—	—	318
Total	$ 49,050	$ 292,166	$ 31,733	$ (280,511)	$ 92,438
Liabilities:					
Commodity derivatives	$ —	$ 355,358	$ 13,092	$ (280,511)	$ 87,939
Interest rate swaps	—	25,327	—	—	25,327
Total	$ —	$ 380,685	$ 13,092	$ (280,511)	$ 113,266

(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 and six months ended June 30, 2008 (in thousands):

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

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

Gains and losses (realized and unrealized) for level 3 commodity derivatives are included in Operating revenues on the Condensed Consolidated Statement of Income. 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. Short-term investments included in level 3 represent auction rate securities held at June 30, 2008. The unrealized losses for these investments are recognized in Accumulated other comprehensive income on the 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 Company Arbitration" within this Note 13, the Company 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 was included in the Company's sale of seven IPP plants on July 11, 2008 (see Note 15).

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 was involved 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 structure of LVC as a "qualifying facility" under federal law, together with existing contracts with Nevada Power was 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 replaced 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 six 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. On July 14, 2008, all conditions to closing were met and the Company completed the purchase. The $940 million purchase price was financed through a $383 million borrowing on the Company's $1 billion acquisition facility and from cash proceeds generated from the Company's sale of the IPP assets. The sale of the IPP assets was completed on July 11, 2008 and is subject to customary closing adjustments.

The Company has capitalized certain incremental acquisition costs incurred related to this acquisition. Total acquisition costs capitalized at June 30, 2008 were approximately $32.7 million consisting of $16.7 million for professional fees and $16.0 million in hardware and software costs. In addition, the Company has expensed certain integration-related costs of approximately $4.1 million and $1.5 million for the three months ended June 30, 2008 and 2007, respectively; and $8.3 million and $1.8 million for the six months ended June 30, 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 from discontinued operations, net of taxes" in the accompanying Condensed Consolidated Statements of Income. Assets and liabilities of the discontinued operations have been reclassified and reflected on the accompanying Condensed Consolidated Balance Sheets as "Assets of discontinued operations" and "Liabilities of discontinued operations." For comparative purposes, all prior periods presented have been restated to reflect the reclassifications on a consistent basis.

Sale of IPP Assets

On April 29, 2008, the Company entered into a definitive agreement to sell seven of its IPP plants to affiliates of Hastings and IIF for $840 million, subject to certain working capital adjustments. The transaction was completed July 11, 2008. Under the agreement, the Company received net pre-tax cash proceeds of $756 million, including the effects of the repayment of approximately $67.5 million of associated project level debt, estimated working capital adjustments and other costs. For business segment reporting purposes, results were previously included in the Power generation segment.

Revenues, net income from discontinued operations and net assets of the divested IPP plants at June 30, were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008*	2007	2008*	2007
Operating revenues	$ 27,705	$ 30,417	$ 54,065	$ 59,453
Pre-tax income from discontinued operations	13,949	9,054	21,853	16,674
Income tax expense	4,884	3,302	7,954	6,093
Net income from discontinued operations	$ 9,065	$ 5,752	$ 13,899	$ 10,581

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

	June 30, 2008	December 31, 2007	June 30, 2007
Current assets	$ 29,437	$ 34,112	$ 31,004
Property, plant and equipment, net of accumulated depreciation	506,609	486,156	478,310
Goodwill	26,500	18,095	18,001
Intangible assets (net of accumulated amortization of $28,958, $28,114 and $26,612, respectively)	20,204	21,023	22,525
Other non-current assets	15,146	13,163	13,811
Current liabilities	(9,148)	(15,615)	(9,922)
Note payable	—	—	(28,500)
Long-tem debt	(67,500)	(73,928)	(80,357)
Other non-current liabilities	(86)	(139)	(109)
Net assets	$ 521,162	$ 482,867	$ 444,763

(16) VARIABLE INTEREST ENTITY

The Company's subsidiary, Black Hills Wyoming, had an Agreement for Lease and Lease with Wygen Funding, Limited Partnership, an unrelated VIE, to lease the Wygen Plant. The Company was considered the "primary" beneficiary and included the VIE in the Company's consolidated financial statements. At the end of the initial lease term in June 2008, the Company elected to purchase the Wygen Plant at the adjusted acquisition cost of $133.1 million. In conjunction with the purchase of the Wygen Plant, the Company retired the $128.3 million Wygen I project debt through borrowings on the Company's revolving credit facility, and extinguished the $111 million guarantee obligation under the Wygen I Plant Lease. Since the plant and its financial activities were previously consolidated into our financial statements, the transaction had minimal impact on our consolidated financial statements.

(17) SUBSEQUENT EVENTS

Sale of IPP Plants

On July 11, 2008, the Company completed the sale of seven of its IPP plants to affiliates of Hastings and IIF for $840 million, subject to certain working capital adjustments. Under the sale agreement, the Company received net pre-tax cash proceeds of approximately $756 million, including the effects of the repayment of approximately $67.5 million of associated project level debt on the Valmont and Arapahoe plants, estimated working capital adjustments and other costs.

Aquila Acquisition

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. On July 14, 2008, all conditions to closing were met and the Company completed the purchase. The $940 million purchase price was financed through a $383 million borrowing on the Company's $1 billion acquisition facility and from cash proceeds generated from the Company's sale of the IPP assets.

Acquisition Credit Agreement Borrowings

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 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 up to $1.0 billion. On July 14, 2008 in conjunction with the completion of the purchase of the Aquila properties, we borrowed $383 million under the Acquisition Facility. The loan termination date is February 5, 2009.

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

We are a diversified energy company operating principally in the United States with two major business groups – utilities and non-regulated energy. We report our business groups in the following segments:

Business Group	**Financial Segment**
Utilities group	Electric utility Electric and gas utility
Non-regulated energy group	Oil and gas Power generation Coal mining Energy marketing

Our utilities group consists of our electric and gas utility segments. Our electric 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.

Beginning July 14, 2008, through our acquisition of one electric utility and four gas utilities from Aquila, we also began to serve more than 600,000 additional utility customers in Colorado, Iowa, Kansas and Nebraska.

<u>Sale of IPP Plants</u>

On April 29, 2008, the Company entered into a definitive agreement to sell seven of its IPP plants to affiliates of Hastings and IIF for $840 million, subject to certain working capital adjustments. The transaction was completed July 11, 2008. Under the agreement, the Company received net pre-tax cash proceeds of approximately $756 million, including the effects of the repayment of approximately $67.5 million of associated project level debt, estimated working capital adjustments and other costs. Additionally, we expect to make income tax payments associated with the gain on the asset sale of approximately $50 million to $75 million. Through tax planning, we expect to defer tax payments in the range of $135 million to $160 million. The pre-tax book gain on the asset sale is in the range of $225 million to $250 million. For business segment reporting purposes, results were previously included in the Power generation segment.

The following power plants were included in the sale to Hastings and IIF:

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

The following power plants 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 CT (Wyoming)	40
Ontario Cogeneration (California)	12
Rupert and Glenns Ferry Cogeneration (Idaho)**	11
Power fund investments (various locations)	5
Total	158

* Mine-mouth coal-fired base load generation
** Capacity represents the Company’s 50 percent interest in the two power plants

Wygen III Power Plant Project

In March 2008, we 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 estimates for AFUDC. Through Black Hills Power we expect to retain ownership of 75 MW of the facility’s capacity with MDU currently being expected to take ownership of the remaining 25 MW. We will retain operations of the facility with life-of-plant site lease, operations and coal supply agreements in place with MDU.

Air-Cooled Condensor Upgrade Project

We recently commenced a project to expand the air-cooled condensors on our Wygen I and Neil Simpson II coal-fired plants. The upgrades will cost approximately $8.0 million per plant and will add approximately 8.2 megawatts of rated capacity to each plant. This represents additional base load installed capacity at approximately $995 per kilowatt. The project is expected to be completed in 2009.

Partial Sale of Wygen I to MEAN

We have a non-binding letter of intent to sell a 23.5 percent ownership interest in the Wygen I plant to MEAN. The sales price will be based on current replacement cost for the coal-fired plant, and accordingly we would expect to realize a significant gain on the completed sale. We would retain operations of the plant and enter into site lease, coal supply and operating agreements with MEAN. We currently expect that an agreement will be finalized by the end of 2008.

We currently have a long-term contract to sell 20 MW of capacity and energy from the Wygen I plant to MEAN, which expires in 2013. This contract would be terminated upon the completion of the sale.

Acquisition of Aquila Utility Assets

On February 7, 2007, we entered into a definitive agreement with Aquila for the acquisition of Aquila's regulated electric utility assets in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa. On July 14, 2008, all conditions to closing were met and the acquisition was completed. The $940 million purchase price was financed through a $383 million borrowing on the Company's $1 billion acquisition facility and from cash proceeds generated from the Company's IPP asset sale, which was completed on July 11, 2008.

We have capitalized certain incremental acquisition costs incurred related to this acquisition. Total acquisition costs capitalized as of June 30, 2008 were approximately $32.7 million, and consisted of $16.7 million for professional fees and $16.0 million in hardware and software costs. In addition, we expensed certain integration-related costs of approximately $4.1 million and $1.5 million for the three months ended June 30, 2008 and 2007, respectively, and $8.3 million and $1.8 million for the six months ended June 30, 2008 and 2007, respectively. These costs are included in Corporate results.

Results of Operations

Executive Summary

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2007.
Results for the three months ended June 30, 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 June 30, 2008 was $13.2 million, or $0.34 per share, compared to $19.5 million, or $0.51 per share, reported for the same period in 2007. For the three month period ended June 30, 2008, net income was $22.2 million or $0.58 per share, compared to $25.1 million, or $0.66 per share, for the same period in 2007.

Utilities earnings were affected by Cheyenne Light benefiting from a 2008 rate increase and higher electric and gas usage, partially offset by increased costs primarily related to Wygen II plant operations and depreciation and lower AFUDC. The Wygen II plant began commercial operation on January 1, 2008. Black Hills Power earnings increased due to higher margins from off-system sales and the impact of AFUDC related to the Wygen III construction partially offset by lower margins on retail and wholesale sales. Fuel and purchased power cost increases reflect additional power purchases to meet native load during scheduled and unscheduled plant outages.

Earnings from oil and gas operations increased for the quarter driven by an increase in revenues due to higher average prices received for oil and gas partially offset by lower production. Operating expenses also increased due to higher LOE due to severe weather impacts and increased production taxes associated with increased revenues. Second quarter 2008 production was 9 percent lower than second quarter 2007 primarily due to weather-related impacts and lower production from non-operated properties. Average hedged oil prices increased 66 percent and average hedged gas prices increased 24 percent.

Losses from power generation reflect the sale of the IPP assets and reclassification to discontinued operations. Continuing operations for this segment include Wygen I, the Gillette CT, Ontario, Rupert and Glenns Ferry and power fund investments. Indirect corporate costs and inter-segment net interest expense not reclassified to discontinued operations were $4.2 million and $2.5 million after-tax for the three months ended June 30, 2008 and 2007, respectively. These costs were historically allocated to the Power generation segment, but will be reallocated in future periods to reflect the recent changes in our business and asset mix.

Lower earnings from the Coal mining segment resulted from increased overburden removal costs, depreciation and coal taxes partially offset by revenue increases from higher production and higher average sale price.

Earnings from energy marketing reflect lower realized natural gas margins received partially offset by higher realized crude oil margins and unrealized mark-to-market gains. Natural gas margins were impacted by changes in market conditions as lower geographic and calendar spreads compared to 2007 contributed to the earnings decline. Lower operating expenses reflect lower incentive compensation related to the decrease in natural gas gross margins.

Earnings from discontinued operations were $9.0 million, or $0.24 per share, for the three month period ended June 30, 2008, compared to $5.6 million, or $0.15 per share, for the same period in 2007. Increased earnings from discontinued operations primarily reflect that during the second quarter of 2008 we ceased depreciation and amortization on the IPP assets to be sold.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007.

Results for the six months ended June 30, 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 six month period ended June 30, 2008 was $24.9 million, or $0.65 per share, compared to $47.2 million, or $1.28 per share, reported for the same period in 2007. For the six month period ended June 30, 2008, net income was $39.0 million or $1.01 per share, compared to $57.6 million, or $1.56 per share, for the same period in 2007.

Utilities earnings were affected by Cheyenne Light benefiting from a 2008 rate increase and higher electric and gas usage, partially offset by increased costs primarily related to Wygen II plant operations and depreciation and lower AFUDC. Black Hills Power earnings increased due to higher margins from off-system sales and the impact of AFUDC related to the Wygen III construction partially offset by lower margins on retail and wholesale sales. Fuel and purchased power cost increases reflect additional power purchased to meet native load during scheduled and unscheduled plant outages.

Earnings from oil and gas operations increased for the six month period driven by higher revenues due to higher average prices received for oil and gas, offset by lower production. Revenues for the period were also negatively impacted by a $2.1 million pre-tax accrual for a royalty settlement with the Jicarilla Apache Nation. Higher LOE and increased production taxes due to the increase in prices partially offset the increased revenues. Year to date 2008 production was 7 percent lower than the same period in 2007 primarily due to weather-related impacts and lower production from non-operated properties. Average hedged oil prices increased 59 percent and average hedged gas prices increased 16 percent.

Losses from power generation reflect the sale of the IPP assets and reclassification to discontinued operations. Continuing operations for this segment include Wygen I, the Gillette CT, Ontario, Rupert and Glenns Ferry and power fund investments. Indirect corporate costs and inter-segment net interest expense not reclassified to discontinued operations were $7.7 million and $5.5 million after-tax for the six month periods ended June 30, 2008 and 2007, respectively. These costs were historically allocated to the Power generation segment, but will be reallocated in future periods to reflect the recent changes in our business and asset mix.

A decrease in earnings from the Coal mining segment was impacted by increased fuel costs, coal taxes, depreciation and overburden removal costs partially offset by revenue increases from higher production and higher average sales price.

Earnings from energy marketing reflect lower realized natural gas margins received and a decrease in unrealized mark-to-market margins, partially offset by higher realized crude oil margins. Natural gas margins were impacted by changes in market conditions as lower geographic and calendar spreads contributed to the earnings decline. Lower operating expenses reflect lower incentive compensation related to the decrease in natural gas gross margins.

Earnings from discontinued operations were $14.1 million, or $0.36 per share, for the six month period ended June 30, 2008, compared to $10.4 million, or $0.28 per share, for the same period in 2007. Increased earnings from discontinued operations primarily reflect that during the second quarter of 2008, we ceased depreciation and amortization on the IPP assets to be sold.

Consolidated Results

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Revenues				
Utilities	$ 93,567	$ 66,039	$ 192,868	$ 149,758
Non-regulated energy	59,706	67,487	113,255	141,264
Corporate	—	—	—	1
	$ 153,273	$ 133,526	$ 306,123	$ 291,023
Income (loss) from continuing operations				
Utilities	$ 9,553	$ 5,924	$ 19,720	$ 15,695
Non-regulated energy	7,533	14,374	11,039	32,389
Corporate	(3,936)	(819)	(5,869)	(933)
	$ 13,150	$ 19,479	$ 24,890	$ 47,151

Income from continuing operations decreased $6.3 million for the three months ended June 30, 2008 due primarily to the following:

- an $8.6 million decrease in Energy marketing earnings;
- a $0.9 million decrease in Coal mining earnings; and
- a $3.1 million increase in unallocated corporate costs.

Partially offset by:

- a $3.3 million increase in Electric and gas utility earnings; and
- a $2.8 million increase in Oil and gas earnings.

Income from continuing operations decreased $22.3 million for the six months ended June 30, 2008 due primarily to the following:

- a $20.9 million decrease in Energy marketing earnings;
- a $0.9 million decrease in Coal mining earnings;
- a $0.8 million decrease in Electric utility earnings; and
- a $4.9 million increase in unallocated corporate costs.

Partially offset by:

- a $4.8 million increase in Electric and gas utility earnings; and
- a $1.8 million increase in Oil and gas 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 June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(in thousands)			
Revenue	$ 57,978	$ 44,972	$ 115,610	$ 92,739
Fuel and purchased power	28,226	16,670	55,725	33,705
Gross margin	29,752	28,302	59,885	59,034
Operating expenses	20,482	18,242	40,023	36,429
Operating income	$ 9,270	$ 10,060	$ 19,862	$ 22,605
Income from continuing operations and net income	$ 5,251	$ 4,881	$ 10,827	$ 11,580

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

Electric Revenue
(in thousands)

	Three Months Ended June 30,			Six Months Ended June 30,		
Customer Base	2008	Percentage Change	2007	2008	Percentage Change	2007
Commercial	$ 13,063	—%	$ 13,094	$ 26,535	1%	$ 26,193
Residential	10,002	3	9,667	22,980	4	22,079
Industrial	5,542	1	5,482	10,838	2	10,578
Municipal sales	639	(1)	647	1,264	3	1,226
Total retail sales	29,246	1	28,890	61,617	3	60,076
Contract wholesale	6,270	8	5,832	13,202	7	12,289
Wholesale off system	19,238	159	7,415	34,335	145	13,998
Total electric sales	54,754	30	42,137	109,154	26	86,363
Other revenue	3,224	14	2,835	6,456	1	6,376
Total revenue	$ 57,978	29%	$ 44,972	$ 115,610	25%	$ 92,739

Megawatt Hours Sold

Customer Base	Three Months Ended June 30, 2008	Percentage Change	2007	Six Months Ended June 30, 2008	Percentage Change	2007
Commercial	162,313	1%	160,482	335,772	3%	326,576
Residential	114,106	7	106,788	277,140	7	259,524
Industrial	109,028	(1)	110,004	211,697	1	209,258
Municipal sales	7,637	(2)	7,788	15,845	4	15,208
Total retail sales	393,084	2	385,062	840,454	4	810,566
Contract wholesale	156,965	3	151,828	328,585	4	316,938
Wholesale off system	283,770	89	150,363	511,511	80	284,212
Total electric sales	833,819	21%	687,253	1,680,550	19%	1,411,716

Electric Utility Power Plant Availability

	Three Months Ended June 30, 2008	2007	Six Months Ended June 30, 2008	2007
Coal-fired plants	75.7%*	93.9%	84.0%*	94.6%
Other plants	85.6%	99.1%	91.0%	99.5%
Total availability	80.6%	96.2%	87.5%	96.8%

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

Megawatt Hours Generated and Purchased

Resources	Three Months Ended June 30, 2008	Percentage Change	2007	Six Months Ended June 30, 2008	Percentage Change	2007
Coal	384,748	(11)%	434,707	817,630	(7)%	875,225
Gas	4,831	(83)	28,643	41,831	22	34,341
	389,579	(16)%	463,350	859,461	(6)%	909,566
MWhs purchased	467,284	84%	254,588	851,865	55%	549,051
Total resources	856,863	19%	717,938	1,711,326	17%	1,458,617

Heating and Cooling Degree Days

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Heating and cooling degree days:				
Actual				
Heating degree days	1,230	857	4,591	3,912
Cooling degree days	29	203	29	203
Percent of normal				
Heating degree days	123%	86%	107%	91%
Cooling degree days	29%	201%	29%	201%

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2007. Income from continuing operations increased $0.4 million from the prior period primarily due to the following:

- Margins from wholesale off-system sales increased $2.0 million. Total wholesale off-system MWhs sold increased 89 percent as we were able to take advantage of favorable market conditions and high availability of the AC/DC tie which enables us to move power between the east and west power grids; and

- Income related to the impact of $0.9 million of AFUDC attributable to the ongoing construction of Wygen III.

Partially offsetting the increases were the following:

- A $1.0 million reduction in retail and wholesale sales margins due to increased fuel and purchased power costs, primarily due to scheduled and unscheduled outages at our Ben French, Osage and Neil Simpson I coal-fired plants. The plants were back online by the end of the second quarter. The duration of the Ben French Plant outage was approximately three months as we accelerated the completion of maintenance projects that were originally scheduled for this plant in 2009. Black Hills Power has a pass-through mechanism for increased purchase power costs for South Dakota customers, which is subject to a $2.0 million threshold before those costs can be passed on to customers. As of June 30, 2008, Black Hills Power had met the $2.0 million threshold; and

- Increased operating expense due to increased repair and maintenance expenses and outside services, primarily related to the plant outages and personnel costs.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007. Income from continuing operations decreased $0.8 million from the prior period primarily due to the following:

- A $2.0 million reduction in retail and wholesale sales margins due to increased fuel and purchased power costs, primarily due to scheduled and unscheduled outages at our Ben French, Osage and Neil Simpson I coal-fired plants. The plants were back online at the end of the second quarter. The duration of the Ben French Plant outage was approximately three months as we accelerated the completion of maintenance projects that were originally scheduled for this plant in 2009. Black Hills Power has a pass-through mechanism for increased purchase power costs for South Dakota customers, which is subject to a $2.0 million threshold before those costs can be passed on to South Dakota customers. As of June 30, 2008, Black Hills Power had met the $2.0 million threshold; and

- Increased operating expense due to increased repair and maintenance expenses and outside services, primarily related to the plant outages and personnel costs.

Partially offsetting the increased costs were the following:

- Margins from wholesale off-system sales increased $2.7 million. Total MWhs increased 80 percent as Black Hills Power was able to take advantage of favorable market conditions and high availability of the AC/DC tie which enables us to move power between the east and west power grids; and

- Income related to the impact of $1.5 million of AFUDC attributable to the ongoing construction of Wygen III.

Electric and Gas Utility

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in thousands)			
Revenue	$ 35,952	$ 21,652	$ 77,928	$ 58,015
Fuel and purchased power and gas	18,316	15,480	42,931	44,069
Gross margin	17,636	6,172	34,997	13,946
Operating expenses	8,984	5,112	17,070	10,439
Operating income	$ 8,652	$ 1,060	$ 17,927	$ 3,507
Income from continuing operations and net income	$ 4,302	$ 1,043	$ 8,893	$ 4,115

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 exceeds the $1.0 million threshold. For changes in these costs that are below 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.

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

Electric Margins
(in thousands)

	Three Months Ended June 30,			Six Months Ended June 30,		
Customer Base	2008*	Percentage Change	2007	2008*	Percentage Change	2007
Retail sales	$ 20,836	25%	$ 16,705	$ 44,427	27%	$ 34,978
Excess energy sales to affiliate	1,610	—	—	2,871	—	—
	22,446	34	16,705	47,298	35	34,978
Other	1,754	—	52	1,843	—	79
Total electric	24,200	44	16,757	49,141	40	35,057
Fuel and purchased power	9,719	(23)	12,577	22,474	(15)	26,591
Total electric margins	$ 14,481	246%	$ 4,180	$ 26,667	215%	$ 8,466

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

Gas Margins
(in thousands)

	Three Months Ended June 30,			Six Months Ended June 30,		
Customer Base	2008	Percentage Change	2007	2008	Percentage Change	2007
Commercial	$ 560	19%	$ 472	$ 1,838	31%	$ 1,398
Residential	2,270	83	1,243	5,763	68	3,428
Industrial	127	49	85	307	23	250
Total gas	2,957	64	1,800	7,908	56	5,076
Other	198	3	192	422	4	404
Total gas margins	$ 3,155	58%	$ 1,992	$ 8,330	52%	$ 5,480

Electric and Gas Sales

	Three Months Ended June 30, 2008	Three Months Ended June 30, Percentage Change	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, Percentage Change	Six Months Ended June 30, 2007
Electric sales - retail MWh	235,540	6%	222,459	490,967	6%	464,289
Electric sales - excess energy sales to affiliate MWh	67,441	—	—	120,949	—	—
Total electric sales - MWh	302,981	36%	222,459	611,916	32%	464,289
Gas sales - Dth	1,001,357	14%	881,983	3,157,677	11%	2,851,568

Electric and Gas Utility
Power Plant Availability

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Coal-fired plant*	99.9%	N/A	96.1%	N/A

* Placed in service January 1, 2008

Megawatt Hours Generated and Purchased

Resources	Three Months Ended June 30, 2008	Three Months Ended June 30, Percentage Change	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, Percentage Change	Six Months Ended June 30, 2007
Coal-fired generation	201,685	100%	—	389,698	100%	—
MWhs purchased	124,884	(49)%	244,683	263,547	(48)%	505,973
Total resources	326,569	33%	244,683	653,245	29%	505,973

Heating and Cooling Degree Days

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Heating and cooling degree days:				
Actual				
Heating degree days	1,306	1,139	4,542	4,162
Cooling degree days	27	90	27	90
Percent of normal				
Heating degree days	106%	92%	104%	95%
Cooling degree days	64%	214%	64%	214%

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2007. Income from continuing operations increased $3.3 million for the three months ended June 30, 2008 compared to the three months ended June 30, 2007 primarily due to the following:

- Increased electric margins of $10.3 million primarily due to an increase in electric rates effective January 1, 2008, a $2.9 million decrease in Fuel and purchased power as fuel for lower cost power generated by the new Wygen II plant replaced higher cost purchased power and a 6 percent increase in retail MWh sales; and

- Gas gross margins increased $1.2 million primarily due to the increase in gas rates effective January 1, 2008 and a 14 percent increase in usage. We believe gross margins are a more useful performance measure than revenues 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 $3.9 million, or 76 percent, primarily due to Wygen II operating costs of approximately $1.6 million and depreciation costs of approximately $1.4 million; and

- Decreased income from AFUDC due to the completion of Wygen II construction.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007. Income from continuing operations increased $4.8 million for the six months ended June 30, 2008 compared to the six months ended June 30, 2007 primarily due to the following:

- Increased electric margins of $18.2 million primarily due to an increase in electric rates effective January 1, 2008, a $4.1 million decrease in Fuel and purchased power as fuel for lower cost power generated by the new Wygen II plant replaced higher cost purchased power and a 6 percent increase in retail MWh sales;

- Gas gross margins increased 52 percent primarily due to the increase in gas rates effective January 1, 2008 and an 11 percent increase in usage. We believe gross margins are a more useful performance measure than revenues 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 $6.6 million, or 64 percent, primarily due to Wygen II operating costs of approximately $2.8 million and depreciation costs of approximately $2.8 million; and

- Decreased income from AFUDC due to the completion of Wygen II construction.

Non-regulated Energy Group

An analysis of results from our Non-regulated energy group's operating segments follows:

Oil and Gas

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(in thousands)			
Revenue	$ 34,209	$ 25,814	$ 60,331	$ 51,657
Operating expenses	21,917	18,488	42,407	36,986
Operating income	$ 12,292	$ 7,326	$ 17,924	$ 14,671
Income from continuing operations and net income	$ 7,197	$ 4,376	$ 9,749	$ 7,967

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Fuel production:				
Bbls of oil sold	102,800	103,500	202,800	206,900
Mcf of natural gas sold	2,856,800	3,183,700	5,420,000	5,862,000
Mcf equivalent sales	3,473,600	3,804,700	6,636,800	7,103,400

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Average price received [(a)]:				
Gas/Mcf [(b)]	$ 7.92	$ 6.39	$ 8.12[(c)]	$ 6.98
Oil/Bbl	$ 96.99	$ 58.26	$ 88.04	$ 55.45
Depletion expense/Mcfe	$ 2.28	$ 2.03	$ 2.30	$ 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 resulting in a $0.42/Mcf price impact

The following are summaries of LOE/Mcfe:

	Three Months Ended June 30, 2008			Three Months Ended June 30, 2007		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$ 1.37	$ 0.18	$ 1.55	$ 0.76	$ 0.31	$ 1.07
Colorado	1.05	0.88[(a)]	1.93	1.21	0.67[(a)]	1.88
Wyoming	1.57	—	1.57	1.34	—	1.34
All other properties	0.68	0.20	0.88	0.51	0.08	0.59
All locations	$ 1.24	$ 0.18	$ 1.42	$ 0.84	$ 0.20	$ 1.04

	Six Months Ended June 30, 2008			Six Months Ended June 30, 2007		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$ 1.45	$ 0.31	$ 1.76	$ 0.99	$ 0.37	$ 1.36
Colorado	1.14	0.86[(a)]	2.00	1.34	0.95[(a)]	2.29
Wyoming	1.68	—	1.68	1.22	—	1.22
All other properties	0.99	0.10	1.09	0.66	0.14	0.80
All locations	$ 1.37	$ 0.21	$ 1.58	$ 0.97	$ 0.26	$ 1.23

(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 June 30, 2008 Compared to Three Months Ended June 30, 2007. Income from continuing operations increased $2.8 million for the three months ended June 30, 2008 compared to the same period in 2007 primarily due to:

- Revenue increased $8.4 million due to a 66 percent increase in the average hedged price of oil received and a 24 percent increase in average hedged price of gas received, partially offset by lower production of 9 percent. The lower production reflects permitting delays, weather impacts in the San Juan Basin and delayed drilling activities on our non-operated properties. We have only invested $19.2 million on oil and gas capital year-to-date and given our current inventory of permitted, drillable locations, we have revised our expected capital spending for 2008 from $94.2 million to approximately $65.0 million.

Partially offsetting these increases were the following:

- A $1.1 million increase in LOE due to costs related to severe weather conditions in New Mexico and increased fuel cost;

- A $2.5 million increase in production taxes due to higher oil and gas prices; and

- A higher effective income tax rate due to a $1.0 million income tax benefit recorded in 2007 from amended federal income tax returns.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007. Income from continuing operations increased $1.8 million for the six months ended June 30, 2008 compared to the same period in 2007 primarily due to:

- Revenue increased $8.7 million due to a 59 percent increase in the average hedged price of oil received and a 16 percent increase in average hedged price of gas received, partially offset by a 7 percent decrease in production. The lower production reflects weather impacts in the San Juan Basin, ongoing federal drilling permit delays, primarily in the Piceance Basin, and delays in drilling activities on our non-operated properties. We have only invested $19.2 million on oil and gas capital year-to-date and given our current inventory of permitted, drillable locations, we have revised our expected capital spending for 2008 from $94.2 million to approximately $65.0 million.

Partially offsetting these increases were the following:

- A $2.8 million decrease due to a royalty settlement, including interest and penalties, with the Jicarilla Apache Nation;

- A $2.2 million increase in LOE due to costs related to severe weather conditions in New Mexico, the expansion of field compression capacity, and increased fuel costs;

- A $3.2 million increase in production taxes due to higher oil and gas prices; and

- A higher effective income tax rate due to a $1.0 million income tax benefit in 2007 from amended federal income tax returns.

Power Generation

On July 11, 2008, the Company completed the sale of seven of its IPP plants with 974 MW of capacity to affiliates of Hastings and IIF. Results of operations for the following retained plants continue to be reported in the Power generation segment:

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

* Mine-mouth coal-fired base load generation
** Capacity represents the Company's 50 percent interest in the two power plants

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(in thousands)			
Revenue	$ 8,511	$ 9,545	$ 17,375	$ 20,075
Operating expenses	7,290	8,951	14,539	17,493
Operating income	$ 1,221	$ 594	$ 2,836	$ 2,582
Loss from continuing operations	$ (525)	$ (319)	$ (1,498)	$ (169)

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Contracted power plant fleet availability:				
Coal-fired plant	93.3%	94.0%	94.2%	93.8%
Other plants	89.5%	93.1%	94.7%	96.3%
Total availability	91.8%	93.6%	94.4%	94.9%

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2007. Losses from continuing operations were impacted by:

- Allocated indirect corporate costs and inter-segment interest expense, including costs related to the IPP assets sold and not reclassified to discontinued operations, of $4.2 million and $2.5 million after-tax for the three months ended June 30, 2008 and 2007, respectively. These costs were historically allocated to the Power generation segment, but will be allocated in future periods to reflect the recent changes in our business and asset mix.

Partially offsetting these decreases were the following:

- Earnings from the Wygen I and Gillette CT II plants were $3.2 million and $2.9 million for the three months ended June 30, 2008 and 2007, respectively; and

- Equity in earnings from unconsolidated subsidiaries of approximately $1.9 million and $0.4 million for the three months ended June 30, 2008 and 2007, respectively.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007. Losses from continuing operations were impacted by:

- Allocated indirect corporate costs and inter-segment interest expense, including costs related to the IPP assets sold and not reclassified to discontinued operations, of $7.7 million and $5.5 million after-tax for the six months ended June 30, 2008 and 2007, respectively. These costs were historically allocated to the Power generation segment, but will be allocated in future periods to reflect the recent changes in our business and asset mix.

Partially offsetting these decreases were the following:

- Earnings from the Wygen I and Gillette CT II plants were $6.6 million and $6.9 million for the six months ended June 30, 2008 and 2007, respectively; and

- Equity in earnings of unconsolidated subsidiaries of approximately $1.9 million and $0.9 million for the six months ended June 30, 2008 and 2007, respectively.

Sale of Emissions Credit

During July 2008, we entered into an agreement to sell nitrogen oxide (NOx) Reclaim Trading Credits allocated to our Ontario facility. The credits sold are for years 2011 and all years thereafter and will likely result in the retirement of the plant by 2010. The sale price and gain on sale was approximately $2.7 million and will be recognized in the financial results of the third quarter of 2008.

Coal Mining

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(in thousands)			
Revenue	$ 12,647	$ 10,002	$ 25,894	$ 19,747
Operating expenses	12,729	8,582	24,346	16,711
Operating (loss) income	$ (82)	$ 1,420	$ 1,548	$ 3,036
Income from continuing operations and net income	$ 496	$ 1,379	$ 2,124	$ 2,995

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(in thousands)			
Tons of coal sold	1,453	1,269	2,998	2,482
Cubic yards of overburden moved	2,623	1,518	5,653	3,213

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2007.
Income from continuing operations from our Coal mining segment for the three months ended June 30, 2008 decreased $0.9 million compared to the same period in the prior year. Results were impacted by the following:

- Operating expenses increased $4.1 million, or 48 percent, during the three months ended June 30, 2008 primarily due to increased overburden removal costs, an increase in diesel fuel costs, higher depreciation due to increased equipment usage, and increased coal taxes due to a higher revenue base. We had a 73 percent increase in cubic yards of overburden moved. In accordance with GAAP, we expense overburden removal costs when incurred, which may not coincide with the timing of revenues from the sale of the tons of coal that were uncovered.

Partially offsetting the increased expenses was the following:

- Revenue increased $2.6 million, or 26 percent, for the three month period ended June 30, 2008 compared to the same period in 2007. Revenues increased due to an increase in average price received and higher quantity of tons of coal sold, primarily due to additional sales to Cheyenne Light for Wygen II and increased train load-out sales.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007.
Income from continuing operations from our Coal mining segment for the six months ended June 30, 2008 decreased $0.9 million compared to the same period in the prior year. Results were impacted by the following:

- Operating expenses increased $7.6 million, or 46 percent, during the six months ended June 30, 2008 primarily due to increased overburden removal costs, an increase in diesel fuel costs, increased coal taxes due to a higher revenue base and increased depreciation due to increased equipment usage. We had a 76 percent increase in cubic yards of overburden moved. This contributed to a $2.6 million increase in overburden costs. In accordance with GAAP, we expense overburden removal costs when incurred, which may not coincide with the timing of revenues from the sale of the tons of coal that were uncovered.

Partially offsetting the increased expenses was the following:

- Revenue increased $6.1 million, or 31 percent, for the three month period ended June 30, 2008 compared to the same period in 2007. Revenues increased due to an increase in average price received and higher quantity of tons of coal sold, primarily due to additional sales to Cheyenne Light for Wygen II and increased train load-out sales.

Energy Marketing

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in thousands)			
Revenue –				
Realized gas marketing gross margin	$ (5,563)	$ 19,110	$ 7,862	$ 40,355
Unrealized gas marketing gross margin	4,151	2,431	(2,472)	8,957
Realized oil marketing gross margin	2,755	1,390	4,328	2,107
Unrealized oil marketing gross margin	3,807	(22)	1,551	(72)
	5,150	22,909	11,269	51,347
Operating expenses	4,544	9,065	10,481	18,053
Operating income	$ 606	$ 13,844	$ 788	$ 33,294
Income from continuing operations and net income	$ 365	$ 8,938	$ 664	$ 21,596

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Natural gas physical sales – MMBtus	1,599,300	1,581,000	1,696,700	1,738,900
Crude oil physical sales – Bbls	6,896	10,803	6,990	8,442

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2007. Income from continuing operations decreased $8.6 million due to:

- A $24.7 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 first quarter of 2008, which resulted in a compressed Rocky Mountain basis spread, which contributed 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 higher margins per barrel marketed. Physical volumes marketed increased 1 percent for natural gas and decreased 36 percent for crude oil. Crude oil volumes decreased due to a decline in spot purchases as greater emphasis has been placed on long-term purchases. This strategy has been enhanced by our investment in proprietary pipeline injection stations which have allowed us to deliver customized services to crude oil producers with greater margin potential.

Partially offsetting these decreases were the following:

- A $5.5 million pre-tax increase in unrealized marketing margins; and
- Lower compensation cost related to the decreased marketing margins.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007. Income from continuing operations decreased $20.9 million due to:

- A $32.5 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 first quarter of 2008 resulting in a compressed Rocky Mountain basis spread, which contributed 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 higher margins per barrel marketed. Physical volumes marketed decreased 2 percent for natural gas and decreased 17 percent for crude oil; and
- A $9.8 million pre-tax decrease in unrealized marketing margins.

Partially offsetting these decreases was the following:

- Lower compensation cost related to the decreased marketing margins.

Corporate

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2007. Losses increased $3.1 million due to increased unallocated costs in the three months ended June 30, 2008, compared to the same period in 2007, primarily as a result of increased transition and integration costs of approximately $1.7 million after-tax related to the recently completed purchase of certain Aquila assets.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007. Losses increased $4.9 million due to increased unallocated costs in the six months ended June 30, 2008, compared to the same period in 2007, primarily as a result of increased transition and integration costs of approximately $4.2 million after-tax related to the recently completed purchase of certain Aquila assets. Partially offsetting the cost increases were $1.1 million in 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 the occurrence of certain agreed-upon terms for permitting and construction progress.

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 six month period ended June 30, 2008, we generated sufficient cash flow from operations to meet our operating needs and to pay dividends on our common stock. We utilized borrowings on our revolving credit facility to pay our scheduled long-term debt maturities and to fund a portion of our property, plant and equipment additions. Our July 14, 2008 acquisition of certain electric and gas utility assets of Aquila for $940 million, subject to customary closing adjustments, was financed through a $383 million borrowing on our $1 billion acquisition facility and from cash proceeds generated from our July 11, 2008 sale of the IPP assets. We plan to fund future property and investment additions including the construction costs of the 100 MW Wygen III generation facility located near Gillette, Wyoming from internally generated cash resources and external financings.

Cash flows from operations of $41.3 million for the six month period ended June 30, 2008 represent a $43.9 million decrease for the six month period ended June 30, 2008 compared to the same period in the prior year due to a $22.3 million decrease in income from continuing operations and from the following:

- A $36.6 million decrease in cash flows from working capital changes. This decrease primarily resulted from a $27.5 million decrease in cash flows from a net purchase 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 $14.7 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 our oil and gas segment related commodity price fluctuations;

- A $6.8 million increase in cash flows related to changes in deferred income taxes which is primarily the result of the inclusion in prior year deferred income taxes of a deferred income tax benefit attributable to amended federal tax returns, net of a reduction in accelerated deductions relating to intangible drilling costs related to our Oil and gas segment and changes in derivative assets and liabilities; and

- A $5.9 million increase in depreciation, depletion and amortization.

During the six months ended June 30, 2008, we had cash outflows from investing activities of $166.9 million, which were primarily due to the following:

- Cash outflows of $127.0 million for property, plant and equipment additions. These outflows include approximately $49.6 million related to the construction of our Wygen III power plant and approximately $28.9 million in oil and gas property maintenance capital and development drilling; and

- Cash outflows of $33.4 million for discontinued operations, primarily related to construction costs of the Valencia power plant, which was included in the IPP asset sale.

- Cash outflows of $7.5 million for short-term investments primarily related to Auction Rate Securities held and previously classified as "cash and cash equivalents."

During the six months ended June 30, 2008, we had net cash inflows from financing activities of $85.2 million, primarily due to:

- $246.0 million net borrowings of funds from our revolving credit facility.

Partially offset by:

- Repayment of $130.3 million of long-term debt, including $128.3 million for the Wygen I project debt; and

- The payment of cash dividends on common stock.

Dividends

At its April 28, 2008 meeting, our Board of Directors declared a quarterly dividend payable June 1, 2008 of $0.35 per common share, equivalent to an annual dividend rate of $1.40 per share. Additionally, at its July 30, 2008 meeting, our Board of Directors declared a quarterly dividend of $0.35 per common share to all shareholders of record on August 15, 2008 which is payable September 1, 2008. Dividends paid on our common stock totaled $26.7 million during the six months ended June 30, 2008, or $0.70 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 six months of 2008. As of June 30, 2008, we had approximately $36.9 million of cash unrestricted for operations. Approximately $2.6 million of the June 30, 2008 cash balance was restricted by subsidiary debt agreements that limit our subsidiaries' ability to dividend cash to the parent company.

On July 10, 2008, our revolving credit facility was increased from $400 million to $525 million. Our 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 3.16 percent one-month borrowing rate as of June 30, 2008).

Our revolving credit facility can be used to fund our working capital needs and for general corporate purposes. At June 30, 2008, we had borrowings of $283.0 million and $49.0 million of letters of credit issued on our revolving credit facility. Available capacity remaining on our revolving credit facility was approximately $68.0 million at June 30, 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 $968.6 million at June 30, 2008, which was approximately $217.5 million in excess of the net worth we were required to maintain under the credit facility. Our long-term debt ratio at June 30, 2008 was 34.1 percent, our total debt leverage (long-term debt and short-term debt) was 44.8 percent, our recourse leverage ratio was approximately 48.0 percent and our interest expense coverage ratio for the twelve month period ended June 30, 2008 was 5.1 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 June 30, 2008, there were outstanding letters of credit issued under the facility of $233.1 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 six months of 2008; on July 15, 2008, Moody's revised the outlook of our credit rating from negative to stable. Our corporate credit rating by S&P was "BBB-;" the outlook is stable. On July 15, 2008 we received a BBB issuer default rating from Fitch.

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 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 up to $1.0 billion. On July 14, 2008 in conjunction with the completion of the purchase of the Aquila properties, we borrowed a single draw of $383 million under the Acquisition Facility; no additional capacity is thus available under the acquisition facility. The loan termination date is February 5, 2009.

Borrowings under the Acquisition Facility 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 and 67.5 basis points during the period from six months and one day after the initial funding to the loan maturity. The facility contains certain customary affirmative and negative covenants which largely replicate the covenants under our existing revolving credit facility.

We initially funded the payment for our June 2008 project debt maturity of $128.3 million on the Wygen I facility through borrowings on our revolving credit facility. We plan to complete a parent company senior unsecured long-term debt offering of $450 million or more in the fourth quarter of 2008. Proceeds of the offering are expected to be used to pay off the $383 million borrowing on the Acquisition Facility and to reduce borrowings on the revolving credit facility.

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 six months ended June 30, 2008, capital expenditures were approximately $128.8 million for property, plant and equipment additions, which were partially financed through approximately $20.1 million of accrued liabilities. We currently expect total capital expenditures for 2008, excluding the Aquila asset acquisition, to approximate $345.3 million, including $27.8 million related to the Valencia 149 MW, simple-cycle gas turbine generating facility located near Albuquerque, New Mexico which was sold as part of the IPP asset sale, $76.2 million for the 100 MW Wygen III power plant located near Gillette, Wyoming (with the assumption we retain 75 percent ownership in the plant), and $65.0 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 executed 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.

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

	Six Months Ended June 30, 2008 Expenditures	Total 2008 Planned Expenditures
	(in thousands)	
Utilities: [1]		
Electric utility - Wygen III[2]	$ 49,558	$ 76,199
Electric utility [3]	21,622	74,000[5]
Electric and gas utility	9,334	18,972
Non-regulated energy:		
Oil and gas	19,212	65,000
Power generation - Valencia[4]	27,847	30,600
Power generation	953	5,802[5]
Coal mining	12,764	22,070
Energy marketing	2	135
Corporate (includes Aquila acquisition costs)	15,362	24,629
	$ 156,654	$ 317,407

(1) Forecasted capital requirements are exclusive of the $940.0 million purchase price and related other costs for the acquisition of Aquila utility assets in 2008, and any maintenance capital subsequent to the acquisition.

(2) Forecasted expenditures of the Wygen III coal-fired plant reflects our expectation that we will retain a 75 percent ownership interest in the plant.

(3) Electric utility capital requirements include approximately $17.2 million for Wygen III-related transmission projects in 2008.

(4) The Valencia power plant was included in the IPP assets sold July 11, 2008.

(5) 2008 forecasted capital requirements include $8.0 million of project costs for air-cooled condenser upgrades for our Neil Simpson II and Wygen I coal-fired plants. Total project costs are expected to be approximately $16.2 million and will add approximately 8.2 MW of rated capacity to each plant. This represents additional base load installed capacity at approximately $995 per kilowatt.

Contractual Obligations

Unconditional purchase obligations for firm transportation and storage fees for our Energy marketing segment increased $39.8 million from $47.9 million at December 31, 2007 to $84.3 million at June 30, 2008. Approximately $21.1 million of the fee obligations relate to the 2009-2011 period with the remaining occuring thereafter.

In addition, contractual obligations of $14.0 million related to the IPP plants sold consisted of $12.7 million of land lease obligations for the Arapahoe, Valmont and Harbor power plants and $1.3 million for a Las Vegas II transmission agreement. These obligations were previously reported as purchase obligations in the Liquidity section of Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations, in our 2007 Annual Report on Form 10-K.

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 reports 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, transmission, and purchased power in our regulated utilities; and our ability to add power generation assets into our regulatory rate base;
- Our ability to successfully integrate and profitably operate any recent 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 prudency 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, renewable portfolio standards, climate change and greenhouse gas legislation;
- 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 six months ended June 30, 2008 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2007	$	3,718 [(a)]
Net cash settled during the period on positions that existed at December 31, 2007		15,262
Change in fair value due to change in assumptions		1,898
Unrealized gain on new positions entered during the period and still existing at June 30, 2008		1,296
Realized loss on positions that existed at December 31, 2007 and were settled during the period		(19,787)
Change in cash collateral[(b)]		50,337
Unrealized gain on positions that existed at December 31, 2007 and still exist at June 30, 2008		1,032
Total fair value of energy marketing positions at June 30, 2008	$	53,756 [(a)]

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

	June 30, 2008	March 31, 2008	December 31, 2007
Net derivative (liabilities) assets	$ (1,606)	$ (8,475)	$ 14,797
Cash collateral	49,050	32,876	(1,287)
Market adjustment recorded in material, supplies and fuel	6,312	4,551	(9,792)
	$ 53,756	$ 28,952	$ 3,718

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

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

	Maturities		
Source of Fair Value	Less than 1 year	1 – 2 years	Total Fair Value
Level 1	$ 49,050	$ —	$ 49,050
Level 2	(2,679)	10,292	7,613
Level 3	(10,457)	1,238	(9,219)
Market value adjustment for inventory (see footnote (a) above)	6,312	—	6,312
Total	$ 42,226	$ 11,530	$ 53,756

The following table presents a reconciliation of our June 30, 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)	$ 53,756
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	86,882
Fair value of all forward positions (non-GAAP)	140,638
Cash collateral included in GAAP marked-to-market fair value	(49,050)
Fair value of all forward positions excluding cash collateral (non-GAAP)	$ 91,588

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 the 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

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)		Price
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	11/16/2007	Basis Swap	04/08 – 12/08	-1,500	$	(0.93)
NWR	11/16/2007	Basis 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

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)		Price
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	07/09 – 09/09	5,000	$	75.00
NYMEX	11/16/2007	Put	10/09 – 12/09	5,000	$	75.00
NYMEX	01/03/2008	Put	01/10 – 03/10	5,000	$	80.00
NYMEX	01/03/2008	Swap	01/10 – 03/10	5,000	$	88.70
NYMEX	01/23/2008	Swap	10/09 – 12/09	5,000	$	83.10
NYMEX	01/23/2008	Swap	01/10 – 03/10	5,000	$	82.90
NYMEX	02/28/2008	Put	01/10 – 03/10	5,000	$	85.00
NYMEX	04/09/2008	Swap	04/10 – 06/10	5,000	$	99.60
NYMEX	04/30/2008	Put	04/10 – 06/10	5,000	$	85.00
NYMEX	05/29/2008	Put	04/10 – 06/10	5,000	$	105.00
NYMEX	07/16/2008	Swap	04/10 – 06/10	5,000	$	135.10
NYMEX	07/16/2008	Swap	07/10 – 09/10	5,000	$	134.90

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 June 30, 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 June 30, 2008 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
April 1, 2008 – April 30, 2008	538 (1)	$ 38.78	—	—
May 1, 2008 – May 31, 2008	—	$ —	—	—
June 1, 2008 – June 30, 2008	—	$ —	—	—
Total	538	$ 38.78	—	—

(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 4. <u>Submission of Matters to a Vote of Security Holders</u>

(a) The Annual Meeting of Shareholders was held on May 20, 2008.

(b) Matters Voted Upon at the Meeting

1. Elected four Class II Directors to serve until the Annual Meeting of Shareholders in 2011.

David R. Emery	
Votes For	32,956,488
Votes Withheld	1,183,470
Kay S. Jorgensen	
Votes For	32,960,183
Votes Withheld	1,179,775
Warren L. Robinson	
Votes For	33,047,446
Votes Withheld	1,092,512
John B. Vering	
Votes For	33,045,498
Votes Withheld	1,094,460

2. Ratified the appointment of Deloitte & Touche LLP to serve as Black Hills Corporation’s independent auditors in 2008.

Votes For	33,880,556
Votes Against	181,697
Abstain	77,705
Broker Non-Votes	—

3. Shareholder Proposal requesting the Board of Directors of Black Hills Corporation take the steps necessary to eliminate classification of terms of its Board of Directors to require that all directors stand for election annually.

Votes For	18,856,631
Votes Against	12,546,078
Abstain	292,108
Broker Non-Votes	4,446,141

Item 6. Exhibits

Exhibit 10.1	Mutual Notice of Extension provided as of April 29, 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 April 30, 2008 and incorporated by reference herein).
Exhibit 10.2	Purchase and Sale Agreement by and between Black Hills Generation, Inc., as Seller, and Southwest Generation Operating Company, LLC, as Buyer, dated as of April 29, 2008 (filed as Exhibit 10 to the Company's Form 8-K filed on May 1, 2008 and incorporated by reference herein).
Exhibit 10.3	Change in Control Agreement dated June 1, 2008 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Company's Form 8-K filed on June 5, 2008 and incorporated by reference herein).
Exhibit 10.4	Form of Change in Control Agreement dated June 1, 2008 between Black Hills Corporation and its Non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Company's Form 8-K filed on June 5, 2008 and incorporated by reference herein).
Exhibit 10.5	Third Amendment to the Credit Agreement dated May 5, 2005 among Black Hills Corporation, as Borrower, ABN AMRO Bank N.V., in its capacity as agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10.1 to the Company's Form 8-K filed on July 14, 2008 and incorporated by reference herein).
Exhibit 10.6	First Amendment to the Credit Agreement dated May 7, 2007 among Black Hills Corporation, as Borrower, ABN AMRO Bank N.V., in its capacity as agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10.2 to the Company's Form 8-K filed on July 14, 2008 and incorporated by reference herein).
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.

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: August 11, 2008

EXHIBIT INDEX

Exhibit Number	Description
Exhibit 10.1	Mutual Notice of Extension provided as of April 29, 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 April 30, 2008 and incorporated by reference herein).
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Exhibit 31

CERTIFICATION

I, David R. Emery, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 11, 2008

/S/ DAVID R. EMERY
David R. Emery
Chairman, President and
Chief Executive Officer and
interim Principal Financial Officer

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Black Hills Corporation (the "Company") on Form 10-Q for the period ended June 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David R. Emery, Chairman, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 11, 2008

/S/ DAVID R. EMERY

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