BLACK HILLS CORP /SD/
Form 10-Q
August 09, 2007
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, 2007.

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 or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer x Accelerated filer o Non-accelerated filer 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, 2007
Common stock, $1.00 par value	37,750,250 shares

TABLE OF CONTENTS

		Page
	Glossary of Terms	3-4
PART I.	FINANCIAL INFORMATION	
Item 1.	Financial Statements	
	Condensed Consolidated Statements of Income Three and Six Months Ended June 30, 2007 and 2006	5
	Condensed Consolidated Balance Sheets June 30, 2007, December 31, 2006 and June 30, 2006	6
	Condensed Consolidated Statements of Cash Flows Six Months Ended June 30, 2007 and 2006	7
	Notes to Condensed Consolidated Financial Statements	8-27
Item 2.	Management s Discussion and Analysis of Financial Condition and Results of Operations	28-51
Item 3.	Quantitative and Qualitative Disclosures about Market Risk	52-55
Item 4.	Controls and Procedures	55
PART II.	OTHER INFORMATION	
Item 1.	Legal Proceedings	56
Item 1A.	Risk Factors	56
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	57
Item 4.	Submission of Matters to a Vote of Security Holders	58
Item 6.	Exhibits	59
	Signatures	60
	Exhibit Index	61

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
Aquila	Aquila, Inc.
Bbl	Barrel
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
BHER	Black Hills Energy Resources, Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
Black Hills Energy	Black Hills Energy, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Generation	Black Hills Generation, Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Wyoming	Black Hills Wyoming, Inc., an indirect, wholly-owned subsidiary of Black Hills Energy, Inc.
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company
Cheyenne Light Pension Plan	The Cheyenne Light, Fuel and Power Company Pension Plan
Dth	Dekatherms
EITF	Emerging Issues Task Force
Enserco	Enserco Energy Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN 48	FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement 109
GAAP	Generally Accepted Accounting Principles
GECC	General Electric Capital Corporation
Great Plains	Great Plains Energy Incorporated
Indeck	Indeck Capital, Inc.
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 Energy, Inc.
Mbbl	One thousand barrels
Mcf	One thousand cubic feet
Mcfe	One thousand cubic feet equivalent
MMBtu	One million British thermal units
MMcf	One million cubic feet
MMcfe	One million cubic feet equivalent
Moody s	Moody s Investor Services, Inc.
MW	Megawatt
MWh	Megawatt-hour
Nevada Power	Nevada Power Company
PNM	PNM Resources, Inc.
PPA	Power Purchase Agreement

SAB	SEC Staff Accounting Bulletin
SAB 108	SAB 108, Effects of Prior Year Misstatement on Current Year Financial Statements
SEC	U. S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS 71, Accounting for the Effects of Certain Types of Regulation
SFAS 109	SFAS 109, Accounting for Income Taxes
SFAS 133	SFAS 133, Accounting for Derivative Instruments and Hedging Activities
SFAS 144	SFAS 144, Accounting for the Impairment of Long-lived Assets
SFAS 157	SFAS 157, Fair Value Measurements
SFAS 158	SFAS 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of FASB Statements No. 87, 88 106 and 132(R)
SFAS 159	SFAS 159, The Fair Value Option for Financial Assets and Financial Liabilities
S&P	Standard & Poor s Rating Services
Valencia	Valencia Power, LLC, an indirect, wholly-owned subsidiary of Black Hills Energy, Inc.
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.

BLACK HILLS CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands, except per share amounts)			
Operating revenues	$ 163,943	$ 153,813	$ 350,476	$ 325,704
Operating expenses:				
Fuel and purchased power	36,598	49,280	87,886	103,409
Operations and maintenance	20,718	22,073	41,278	44,077
Administrative and general	26,306	20,105	51,969	45,056
Depreciation, depletion and amortization	24,914	22,378	48,082	43,266
Taxes, other than income taxes	10,091	7,546	19,990	18,097
	118,627	121,382	249,205	253,905
Operating income	45,316	32,431	101,271	71,799
Other income (expense):				
Interest expense	(9,977)	(12,910)	(21,086)	(24,910)
Interest income	705	346	1,439	1,014
Allowance for funds used during construction equity	1,206		3,040	
Other (expense) income, net	(2)	123	346	412
	(8,068)	(12,441)	(16,261)	(23,484)
Income from continuing operations before equity in earnings of unconsolidated subsidiaries, minority interest and income taxes	37,248	19,990	85,010	48,315
Equity in earnings (loss) of unconsolidated subsidiaries	673	(1,145)	1,518	(632)
Minority interest	(95)	(91)	(188)	(177)
Income tax expense	(12,595)	(6,386)	(28,608)	(16,577)
Income from continuing operations	25,231	12,368	57,732	30,929
(Loss) income from discontinued operations, net of taxes	(133)	(611)	(181)	6,979
Net income	$ 25,098	$ 11,757	$ 57,551	$ 37,908
Weighted average common shares outstanding:				
Basic	37,588	33,164	36,387	33,142
Diluted	38,007	33,506	36,793	33,493
Earnings per share:				
Basic				
Continuing operations	$ 0.67	$ 0.37	$ 1.59	$ 0.93
Discontinued operations		(0.02)	(0.01)	0.21
Total	$ 0.67	$ 0.35	$ 1.58	$ 1.14
Diluted				
Continuing operations	$ 0.66	$ 0.37	$ 1.57	$ 0.92
Discontinued operations		(0.02)	(0.01)	0.21
Total	$ 0.66	$ 0.35	$ 1.56	$ 1.13
Dividends paid per share of common stock	$ 0.34	$ 0.33	$ 0.68	$ 0.66

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, 2007	December 31, 2006	June 30, 2006
	(in thousands, except share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 40,172	$ 36,939	$ 42,234
Restricted cash	5,341	2,004	
Receivables (net of allowance for doubtful accounts of $4,735; $4,202 and $4,077, respectively)	277,552	263,109	195,090
Materials, supplies and fuel	132,986	92,560	96,871
Derivative assets	40,138	69,244	29,204
Other assets	9,400	9,221	8,353
Assets of discontinued operations	1,135	1,424	6,058
	506,724	474,501	377,810
Investments	23,506	23,808	23,244
Property, plant and equipment	2,383,561	2,242,396	2,093,519
Less accumulated depreciation and depletion	(635,651)	(596,029)	(554,167)
	1,747,910	1,646,367	1,539,352
Other assets:			
Derivative assets	5,413	2,871	3,149
Goodwill	30,171	30,563	30,563
Intangible assets (net of accumulated amortization of $27,411; $25,852 and $24,293, respectively)	22,870	24,429	25,989
Other	66,369	42,137	40,993
	124,823	100,000	100,694
	$ 2,402,963	$ 2,244,676	$ 2,041,100
LIABILITIES AND STOCKHOLDERS EQUITY			
Current liabilities:			
Accounts payable	$ 229,979	$ 224,009	$ 159,207
Accrued liabilities	91,594	95,020	66,775
Derivative liabilities	17,069	24,041	14,959
Deferred income taxes	4,769	1,215	1,450
Notes payable	112,500	145,500	98,500
Current maturities of long-term debt	143,376	17,106	11,125
Accrued income taxes	30,306	19,561	8,311
Liabilities of discontinued operations	724	2,526	5,979
	630,317	528,978	366,306
Long-term debt, net of current maturities	469,394	628,340	660,147
Deferred credits and other liabilities:			
Deferred income taxes	192,492	174,332	149,129
Derivative liabilities	2,769	1,530	1,249
Other	132,866	116,297	98,309
	328,127	292,159	248,687
Minority interest in subsidiaries	4,978	5,158	5,103
Stockholders equity:			
Common stock equity			
Common stock $1 par value; 100,000,000 shares authorized; Issued 37,768,792; 33,404,902 and 33,294,945 shares, respectively	37,769	33,405	33,295
Additional paid-in capital	556,981	409,826	406,196
Retained earnings	382,254	348,245	327,135
Treasury stock at cost 42,209; 35,700 and 36,245 shares, respectively	(1,189)	(920)	(931)
Accumulated other comprehensive loss	(5,668)	(515)	(4,838)
	970,147	790,041	760,857

$ 2,402,963	$ 2,244,676	$ 2,041,100

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,	
	2007	2006
	(in thousands)	
Operating activities:		
Net income	$ 57,551	$ 37,908
Loss (income) from discontinued operations, net of taxes	181	(6,979)
Income from continuing operations	57,732	30,929
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	48,082	43,266
Net change in derivative assets and liabilities	(12,382)	(3,138)
Deferred income taxes	8,052	11,809
Distributed earnings in associated companies	500	4,818
Allowance for funds used during construction equity	(3,040)	
Change in operating assets and liabilities:		
Materials, supplies and fuel	(14,944)	14,672
Accounts receivable and other current assets	(15,111)	70,079
Accounts payable and other current liabilities	11,645	(77,541)
Other operating activities	7,517	12,417
Net cash provided by operating activities of continuing operations	88,051	107,311
Net cash used in operating activities of discontinued operations	(2,906)	(665)
Net cash provided by operating activities	85,145	106,646
Investing activities:		
Property, plant and equipment additions	(111,389)	(150,201)
Proceeds from the sale of business operations		40,735
Other investing activities	(3,143)	(505)
Net cash used in investing activities of continuing operations	(114,532)	(109,971)
Net cash provided by investing activities of discontinued operations	2,343	2,939
Net cash used in investing activities	(112,189)	(107,032)
Financing activities:		
Dividends paid	(24,218)	(21,959)
Common stock issued	148,663	2,233
(Decrease) increase in short-term borrowings, net	(61,500)	43,500
Long-term debt repayments	(32,676)	(10,692)
Other financing activities	(555)	(5)
Net cash provided by financing activities of continuing operations	29,714	13,077
Net cash provided by financing activities of discontinued operations		
Net cash provided by financing activities	29,714	13,077
Increase in cash and cash equivalents	2,670	12,691
Cash and cash equivalents:		
Beginning of period	37,530 [(a)]	34,198 [(c)]
End of period	$ 40,200	$ 46,889 [(b)]
Supplemental disclosure of cash flow information:		
Non-cash investing and financing activities-		
Property, plant and equipment acquired with accrued liabilities or short-term debt	$ 51,071	$ 20,801
Cash paid during the period for-		
Interest (net of amounts capitalized)	$ 20,229	$ 26,095
Income taxes paid (net of amounts refunded)	$ 7,483	$ 12,514

(a) Includes approximately $0.6 million at December 31, 2006 of cash included in the assets of discontinued operations.
(b) Includes approximately $4.7 million at June 30, 2006 of cash included in the assets of discontinued operations.
(c) Includes approximately $2.4 million at December 31, 2005 of cash included in the assets of discontinued operations.

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

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements

(unaudited)

(Reference is made to Notes to Consolidated Financial Statements

included in the Company s 2006 Annual Report on Form 10-K)

(1) MANAGEMENT S STATEMENT

The 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 2006 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, 2007, December 31, 2006 and June 30, 2006 financial information and are of a normal recurring nature. Some of the Company s operations are highly seasonal and revenues from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market price. The results of operations for the three and six months ended June 30, 2007, 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

FIN 48

The Company adopted FIN 48 on January 1, 2007 (see Note 8). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS 109 and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return.

SAB 108

During September 2006, the staff of the SEC released SAB 108. SAB 108 provides guidance on how the effects of the carryover or reversal of prior year financial statement misstatements should be considered in quantifying a current year misstatement. Prior practice allowed the evaluation of materiality on the basis of (1) the error quantified as the amount by which the current year income statement was misstated (rollover method) or (2) the cumulative error quantified as the cumulative amount by which the current year balance sheet was misstated (iron curtain method). Reliance on either method in prior years could have resulted in misstatement of the financial statements. The guidance provided in SAB 108 requires both methods to be used in evaluating materiality. Immaterial prior year errors may be corrected with the first filing of prior year financial statements after adoption. The cumulative effect of the correction can either be reported in the carrying amounts of assets and liabilities as of the beginning of that fiscal year, and the offsetting adjustment made to the opening balance of retained earnings for that year, or by restating prior periods. Disclosure requirements include the nature and amount of each individual error being corrected in the cumulative adjustment, as well as a disclosure of when and how each error being corrected arose and the fact that the errors had previously been considered immaterial. SAB 108 was effective January 1, 2007. SAB 108 did not have a material effect on the Company s consolidated financial position, results of operations or cash flows.

(3) RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

SFAS 157

During September 2006, the FASB issued SFAS 157, which applies to other accounting pronouncements that require or permit fair value measurements. This Statement defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. Management is currently evaluating the impact SFAS 157 will have on the Company s consolidated financial statements.

SFAS 159

During February 2007, the FASB issued SFAS 159, which 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 is effective for fiscal years beginning after November 15, 2007. Management is currently evaluating the impact SFAS 159 will have on the Company s consolidated financial statements.

(4) MATERIALS, SUPPLIES AND FUEL

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

Major Classification	June 30, 2007	December 31, 2006	June 30, 2006
Materials and supplies	$ 35,067	$ 31,946	$ 28,077
Fuel	6,444	9,663	8,580
Gas and oil held by Energy marketing*	91,475	50,951	60,214
Total materials, supplies and fuel	$ 132,986	$ 92,560	$ 96,871

* As of June 30, 2007, December 31, 2006 and June 30, 2006, market adjustments related to natural gas held by Energy marketing and recorded in inventory were $(6.4) million, $(31.5) million and $(4.3) million, respectively (see Note 12 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 and gas imbalances held on account with pipelines. 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. A substantial majority of the gas was economically hedged at the time of purchase either through a fixed price physical or financial forward sale.

(5) LONG-TERM DEBT, NOTES PAYABLE AND GUARANTEES

Note Payable

During June 2007, the Company entered into a short-term, non-interest bearing, secured promissory note payable to Public Service Company of New Mexico in connection with the purchase of certain equipment and related assets for the Company's Valencia project in New Mexico. The secured promissory note payable is due December 2007, and is secured by the purchased equipment and related assets. The Company recorded the promissory note payable at the stated amount of the debt of $30.0 million, less interest imputed at a rate of 6 percent totaling $0.9 million, for a net amount of $29.1 million.

During the first quarter of 2007, the Company repaid the then existing $145.5 million borrowing balance outstanding on its revolving credit facility with proceeds from the Company s February 22, 2007 equity issuance (see Note 9).

Long-term Debt

On April 30, 2007, the Company called its outstanding debt with GE Capital in the amount of $23.5 million. In conjunction with this, the Company expensed $0.1 million in unamortized deferred finance costs. The associated payment guarantees provided by the Company were also terminated.

The Company has classified the $128.3 million Wygen I project debt to current maturities as the debt has a maturity date of June 2008. The Company intends to refinance this debt with other long-term financing prior to its maturity.

Amendments to Revolver

On March 13, 2007, the Company entered into a second amendment to its revolving credit facility. The second amendment (i) increased the limit for borrowings or other credit accommodations for the separate credit facility for the Company s energy marketing subsidiary from $260 million to $300 million, (ii) increased the allowed total commitments under the facility without requiring amendment of the facility from $500 million to $600 million, (iii) effective with the acquisition of certain electric and gas utility assets from Aquila, will increase the recourse leverage ratio limit from 0.65 to 1.00 to 0.70 to 1.00 for the first year after completion of the Aquila asset acquisition, reverting to 0.65 to 1.00 thereafter, and (iv) allowed for other modifications to enable the Company to complete the Aquila asset acquisition.

Guarantees

During the six months ended June 30, 2007, the Company had the following changes to its guarantees:

Extinguished two guarantees totaling $24.2 million at December 31, 2006 related to the payment and performance under our GE Capital debt obligations. Our outstanding debt obligations with GE Capital were paid on April 30, 2007;

The $0.3 million guarantee for the payments of Black Hills Power under various transactions with Idaho Power Company expired on March 1, 2007;

The $3.0 million guarantee for the payments of Cheyenne Light under various transactions with Questar Energy Trading Company expired on March 31, 2007;

Issued a guarantee for obligations and damages, if any, due by Valencia under a power purchase agreement with Public Service Company of New Mexico for up to $12.0 million and expiring in 2028; and

Issued a guarantee for up to $7.0 million related to the obligations of Enserco under an agency agreement whereby Enserco provides services to structure up to $100.0 million of certain transactions involving the buying, selling, transportation and storage of natural gas on behalf of another energy company and which expires in 2008.

(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, 2007	Three Months		Six Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 25,231		$ 57,732	
Basic earnings	25,231	37,588	57,732	36,387
Dilutive effect of:				
Stock options		112		107
Estimated contingent shares issuable for prior acquisition		159		159
Others		148		140
Diluted earnings	$ 25,231	38,007	$ 57,732	36,793

Period ended June 30, 2006	Three Months		Six Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 12,368		$ 30,929	
Basic earnings	12,368	33,164	30,929	33,142
Dilutive effect of:				
Stock options		79		81
Estimated contingent shares issuable for prior acquisition		159		159
Others		104		111
Diluted earnings	$ 12,368	33,506	$ 30,929	33,493

(7) COMPREHENSIVE INCOME

The following table presents the components of the Company s comprehensive income

(in thousands):

	Three Months Ended June 30,	
	2007	2006
Net income	$ 25,098	$ 11,757
Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $(5,686) and $(1,028), respectively)	10,087	1,297
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $2,700 and $(96), respectively)	(4,798)	121
Comprehensive income	$ 30,387	$ 13,175

	Six Months Ended June 30,	
	2007	2006
Net income	$ 57,551	$ 37,908
Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $(1,794) and $(3,318), respectively)	3,723	5,162
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $4,372 and $109, respectively)	(8,876)	(170)
Comprehensive income	$ 52,398	$ 42,900

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 Investees	Total
As of June 30, 2007	$ 2,892	$ (8,404)	$ (156)	$ (5,668)
As of December 31, 2006	$ 8,119	$ (8,404)	$ (230)	$ (515)
As of June 30, 2006	$ (1,699)	$ (2,936)	$ (203)	$ (4,838)

(8) INCOME TAXES

The Company adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, the Company recognized an approximate $0.7 million benefit from a decrease in the liability for unrecognized tax benefits. This benefit was accounted for as an adjustment to the January 1, 2007 balance of retained earnings.

The total gross amount of unrecognized tax benefits at January 1, 2007 was approximately $72.6 million. The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $2.0 million (net of the federal benefit on state tax items and interest) at the date of adoption.

It is the Company s continuing practice to recognize penalties and/or interest related to income tax matters in income tax expense. The Company had no penalties accrued and approximately $0.4 million for the accrual of interest income at the date of adoption of FIN 48.

The Company files income tax returns in the U.S. federal jurisdiction, various state jurisdictions and Canada. The Company is no longer subject to U.S. federal examination for tax years before 2004. However, the Company is under examination by a state taxing authority for tax years 2001 through 2003 and remains subject to examination by Canadian income tax authorities for tax years as early as 1999.

The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statute of limitations prior to June 30, 2008.

(9) 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 2006 Annual Report on Form 10-K.

Private Placement of Common Stock

On February 22, 2007, the Company completed the issuance and sale of approximately 4.17 million shares of common stock at a price of $36.00 per share in a private placement offering. The Company used the approximate $145.6 million of net proceeds from this offering for debt reduction.

These shares were not initially registered under the Securities Act of 1933, therefore restricting the purchasers ability to offer or sell the shares. The offering agreements required the Company to register the related securities with the SEC within a specified period of time, and the Company has performed this obligation. In addition, the Company must maintain an effective shelf registration statement with the SEC, allowing resale of the restricted shares, until all related shares have been resold or cease to be restricted. If the Company fails to maintain an effective shelf registration statement in accordance with the terms of the offering agreements, it may be required to pay damages to the purchasers at a per thirty-day rate of 1.0 percent of the related share purchase price until the default is cured. The total damage payments under the agreements are limited to 10.0 percent of the related share purchase price. The Company believes the likelihood of making any payments under the damage provisions is remote and accordingly has not recognized any liability within its consolidated financial statements.

Equity Compensation Plans

Effective January 1, 2007, the Company granted 35,026 target performance shares to certain officers and business unit leaders of the Company for the January 1, 2007 through December 31, 2009 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. In addition, the Company s stock price must also increase during the performance period.

Participants may earn additional performance shares if the Company s total shareholder return exceeds the 50th percentile of the selected peer group. 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 $34.17 per share.

The Company issued 33,143 shares of common stock under the short-term incentive compensation plan during the six months ended June 30, 2007. Pre-tax compensation cost related to the award was approximately $1.2 million, which was accrued for in 2006.

The Company granted 43,556 restricted common shares during the six months ended June 30, 2007. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $1.6 million will be recognized over the three-year vesting period.

122,954 stock options were exercised during the six months ended June 30, 2007, at a weighted-average exercise price of $28.94 per share providing $3.6 million of proceeds to the Company.

Total compensation expense recognized for all equity compensation plans for the three months ended June 30, 2007 and 2006 was $2.0 million and $0.9 million, respectively, and for the six month periods ended June 30, 2007 and 2006 was $3.0 million and $1.7 million, respectively.

(10) 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,	
	2007	2006	2007	2006
Service cost	$ 687	$ 649	$ 1,374	$ 1,298
Interest cost	1,129	1,041	2,258	2,082
Expected return on plan assets	(1,374)	(1,247)	(2,748)	(2,494)
Prior service cost	38	38	76	76
Net loss	127	227	254	454
Net periodic benefit cost	$ 607	$ 708	$ 1,214	$ 1,416

The Company made a $0.5 million contribution to the Cheyenne Light Pension Plan in the first quarter of 2007; no additional contributions are anticipated to be made to the Plans during the 2007 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,	
	2007	2006	2007	2006
Service cost	$ 103	$ 87	$ 206	$ 174
Interest cost	289	270	578	540
Prior service cost	3	3	6	6
Net loss	178	199	356	398
Net periodic benefit cost	$ 573	$ 559	$ 1,146	$ 1,118

The Company anticipates that it will need to make contributions to the Supplemental Plans for the 2007 fiscal year of approximately $0.7 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,	
	2007	2006	2007	2006
Service cost	$ 135	$ 164	$ 270	$ 328
Interest cost	207	203	414	406
Net transition obligation	15	38	30	76
Prior service cost		(6)		(12)
Net gain/loss	(4)		(8)	
Net periodic benefit cost	$ 353	$ 399	$ 706	$ 798

The Company anticipates that it will make contributions to the Healthcare Plans for the 2007 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, 2007 and 2006.

(11) 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, 2007, substantially all of the Company s operations and assets are located within the United States.

The Company conducts its operations through the following six reporting segments: Retail Services group consisting of the following segments: 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; and Wholesale Energy group, consisting of the following segments: Oil and gas, which produces, explores and operates oil and natural gas interests located in the Rocky Mountain region, Texas, California and other states; Power generation, which produces and sells power and capacity to wholesale customers with plants concentrated in Colorado, Nevada, Wyoming and California; Coal mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; and Energy marketing, which markets natural gas, crude oil and related services primarily in the western and central regions of the United States and Canada.

Segment information follows the same accounting policies as described in Note 20 of the Notes to Consolidated Financial Statements in the Company s 2006 Annual Report on Form 10-K. In accordance with the provisions of SFAS 71, intercompany fuel sales to the electric utility are not eliminated.

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

	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Three Month Period Ended June 30, 2007			
Retail services:			
Electric utility	$ 44,387	$ 585	$ 4,881
Electric and gas utility	21,652		1,043
Wholesale energy:			
Oil and gas	25,814		4,376
Power generation	39,962		5,433
Coal mining	6,424	3,578	1,379
Energy marketing	22,909		8,938
Corporate			(819)
Inter-segment eliminations		(1,368)	
Total	$ 161,148	$ 2,795	$ 25,231

	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Three Month Period Ended June 30, 2006			
Retail services:			
Electric utility	$ 46,405	$ 631	$ 2,436
Electric and gas utility	29,730		864
Wholesale energy:			
Oil and gas	21,313		2,042
Power generation	38,697		2,379
Coal mining	3,854	2,913	768
Energy marketing	11,624		4,264
Corporate	16		(385)
Inter-segment eliminations		(1,370)	
Total	$ 151,639	$ 2,174	$ 12,368

Six Month Period Ended June 30, 2007	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Retail services:			
Electric utility	$ 91,743	$ 996	$ 11,580
Electric and gas utility	58,015		4,115
Wholesale energy:			
Oil and gas	51,657		7,967
Power generation	79,528		10,412
Coal mining	12,641	7,106	2,995
Energy marketing	51,347		21,596
Corporate	1		(933)
Inter-segment eliminations		(2,558)	
Total	$ 344,932	$ 5,544	$ 57,732

Six Month Period Ended June 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Retail services:			
Electric utility	$ 90,209	$ 795	$ 7,335
Electric and gas utility	73,428		2,261
Wholesale energy:			
Oil and gas	46,550		7,432
Power generation	72,290		4,471
Coal mining	9,850	6,188	2,183
Energy marketing	28,581		10,511
Corporate	32		(3,264)
Inter-segment eliminations		(2,219)	
Total	$ 320,940	$ 4,764	$ 30,929

During 2007, the Company has added approximately $35.6 million on the ongoing construction of the Wygen II power plant within our electric and gas utility segment; approximately $34.7 million on maintenance capital and development drilling within our oil and gas segment; and approximately $39.7 million on assets related to the Valencia project in our power generation segment. Other than these significant additions and changes beyond normal operating activities, 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 2006 Annual Report on Form 10-K.

(12) 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 2006 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, 2007		Outstanding at December 31, 2006		Outstanding at June 30, 2006	
(in thousands of MMBtus)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
Natural gas basis swaps purchased	179,020	18	138,111	22	110,281	16
Natural gas basis swaps sold	195,952	18	148,720	22	118,342	16
Natural gas fixed for float swaps purchased	33,520	24	38,239	16	29,537	17
Natural gas fixed for float swaps sold	59,401	24	59,061	15	40,604	17
Natural gas physical purchases	81,261	18	87,782	22	80,193	28
Natural gas physical sales	108,359	28	106,500	34	128,747	40
Natural gas options purchased	9,266	9	22,373	15	18,145	18
Natural gas options sold	8,832	9	22,373	15	18,145	18

	Outstanding at June 30, 2007		Outstanding at December 31, 2006		Outstanding at June 30, 2006	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of Bbls)						
Crude oil physical purchases	2,178	4	1,600	4	1,785 [(a)]	4
Crude oil physical sales	2,092	5	1,367	7	1,568 [(a)]	4
Crude oil swaps purchased	465	15	240	12	360	18
Crude oil swaps sold	465	15	240	12	360	18
(Dollars, in thousands)						
Canadian dollars purchased	$ 41,000	2	$ 44,000	1	$ 18,000	2
Canadian dollars sold	$		$		$ 11,000	5

(a) The Company began marketing crude oil in the Rocky Mountain region during May 2006.

Derivatives and certain natural gas and crude oil marketing activities were marked to fair value on June 30, 2007, December 31, 2006 and June 30, 2006, 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	Unrealized Gain
June 30, 2007	$ 32,722	$ 184	$ 15,235	$ 470	$ 17,201
December 31, 2006	$ 53,728	$ 4	$ 23,296	$ 377	$ 30,059
June 30, 2006	$ 24,631	$ 697	$ 11,673	$ 70	$ 13,585

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in a fair value hedge transaction. These volumes are stated at market value using published spot 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, 2007, December 31, 2006 and June 30, 2006, the market adjustments recorded in inventory were $(6.4) million, $(31.5) million and $(4.3) million, respectively.

Activities Other Than Trading

Oil and Gas Exploration and Production

On June 30, 2007, December 31, 2006 and June 30, 2006, 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, 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
December 31, 2006								
Crude oil swaps/options	240,000	1.00	$ 524	$	$ 362	$	$ 36	$ 126
Natural gas swaps	10,588,000	1.25	13,485	2,000	309	175	15,339	(338)
			$ 14,009	$ 2,000	$ 671	$ 175	$ 15,375	$ (212)
June 30, 2006								
Crude oil swaps	360,000	1.00	$ 302	$	$ 3,286	$ 1,179	$ (4,465)	$ 302
Natural gas swaps	4,485,000	0.60	3,748	202			3,950	
			$ 4,050	$ 202	$ 3,286	$ 1,179	$ (515)	$ 302

*crude in Bbls, gas in MMBtus

Based on June 30, 2007 market prices, a $4.5 million gain would be realized and reported in pre-tax earnings during the next twelve months related to hedges of production. Estimated and actual realized gains will likely change during the next twelve months as market prices change.

Fuel in Storage

On June 30, 2007, December 31, 2006 and June 30, 2006, the Company had the following swaps 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)	Unrealized Gain
June 30, 2007								
Natural gas swaps	455,000	0.83	$	$	$ 76	$	$ (76)	$
December 31, 2006								
Natural gas swaps	380,000	0.25	$ 1,220	$	$	$	$ 878	$ 342
June 30, 2006								
Natural gas swaps	155,000	0.75	$ 73	$	$	$	$ 73	$

*gas in MMBtus

Based on June 30, 2007 market prices, a loss of $(0.1) million would be realized and reported in pre-tax earnings during the next twelve months related to the cash flow hedge. Estimated and actual realized losses will likely change during the next twelve months as market prices change.

Financing Activities

On June 30, 2007, December 31, 2006 and June 30, 2006, 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 Income	Pre-tax Income
June 30, 2007									
Interest rate swaps	$ 150,000	5.04%	9.25	$ 384	$ 4,916	$ 55	$	$ 5,245	$
December 31, 2006									
Interest rate swaps	$ 150,000	5.04%	9.75	$ 287	$ 867	$ 74	$ 978	$ 102	$
June 30, 2006									
Interest rate swaps	$ 75,000	4.93%	9.50	$ 350	$ 2,250	$	$	$ 2,566	$ 34

Based on June 30, 2007 market interest rates and balances, a gain of approximately $0.3 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized gains will likely change during the next twelve months as market interest rates change.

(13) POWER PLANT PROJECT AND POWER PURCHASE AGEEMENT

In April 2007, the Company entered into a power purchase agreement to provide electric power to Public Service Company of New Mexico, a regulated electric and natural gas utility subsidiary of PNM.

Under the terms of the agreement, the Company will provide the capacity and energy of a 149 MW, simple-cycle gas turbine generation facility to be located near Albuquerque, New Mexico. The project is expected to cost approximately $101 million, and has a commercial operation in-service date in June 2008. If the Company would fail to meet the June 2008 in-service date, significant penalties could be incurred under the delay damage provisions that are customary within agreements of this nature. The agreement is a customary tolling agreement, where the Company receives variable and fixed fees for the plant s availability and operation, and Public Service Company of New Mexico will be responsible for providing fuel for the operation. In addition, the agreement affords the Company favorable change of law and government impositions pass-throughs to Public Service Company of New Mexico. The duration of the power purchase agreement is 20 years. During the term of the agreement, Public Service Company of New Mexico is also provided an option to acquire a 50 percent equity interest in this project for a price equal to the fair market value at the time of the option exercise, with a minimum price equal to book value.

On June 20, 2007, the Company purchased certain equipment and assets related to the Valencia project from Public Service Company of New Mexico. The assets included the power plant turbine, permits, land and other auxiliary equipment. The purchase price was approximately $40.6 million, paid through entering into a $30.0 million short-term promissory note, payable to Public Service Company of New Mexico in December 2007, and $10.6 million in cash.

24

(14) LEGAL PROCEEDINGS

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 2006 Annual Report on Form 10-K.

Earn-Out Litigation

As disclosed in previous filings with the SEC, the Company has ongoing litigation with the former Indeck stockholders. On March 12, 2007, the Court granted, in part, the Company s Motion to Dismiss the Amended Complaint. The Court dismissed Counts 1 and 5 of the Amended Complaint. Count 1 included all claims of fraud against individual defendants. Those individuals were not named in other counts of the Amended Complaint, so they were dismissed as parties to the lawsuit. Count 5 asserted a claim for breach of the covenant of good faith and fair dealing relating to the alleged destruction of evidence. The Court approved the amendment of the complaint on other theories. The Company expects to file pre-trial motions to dismiss some or all of these claims. To the extent motions to dismiss are denied, a trial of this matter is set to commence on February 25, 2008.

The parties retained an arbitrator who will direct the process and decide the Earn-Out issues presently in arbitration, according to the procedure stated in the Merger Agreement. No date for a final decision has been set by the arbitrator.

The outcome of this matter is uncertain, as is the amount of contingent merger consideration that could be awarded following arbitration and/or litigation. If any additional merger consideration is awarded, it would be recorded as additional goodwill, which would be subject to a recoverability analysis under GAAP.

Las Vegas Cogeneration/Nevada Power Company Arbitration

On March 16, 2007, Nevada Power filed a Demand for Arbitration pursuant to a Power Purchase Agreement dated May 27, 1992, (the Agreement) between Nevada Power and LVC. Nevada Power asserts that LVC is in breach of its obligation under the Agreement to maintain a reliable fuel supply throughout the term of the Power Contract. On July 5, 2007, Nevada Power served an Amended Demand for Arbitration. The relief Nevada Power requests include: (1) A determination that the Agreement requires LVC to obtain and maintain firm, long-term fuel supply and transportation agreements for the full term of the Agreement; (2) A determination that LVC failed to honor this obligation; (3) A determination that LVC s failure to obtain and maintain firm fuel supply and transportation agreements constitutes a material breach of the Agreement; and (4) An order of specific performance requiring LVC to enter into long-term fuel supply and transportation agreements to cure the alleged breach.

LVC denies all these claims and filed its response to the Demand for Arbitration, asserting the following defenses: (1) That Nevada Power failed to honor its contractual obligation to properly negotiate in good faith before filing the Demand for Arbitration; (2) That LVC has complied with its obligations relating to fuel supply and transportation; and (3) That numerous other affirmative defenses preclude Nevada Power from receiving the relief requested.

The arbitration demand was filed with the American Arbitration Association, pursuant to its Commercial Arbitration Rules. The parties selected an arbitrator and expect resolution to the matter by the end of 2007. While the Company cannot predict the final timing or outcome of this action, and it is not expected to have a material impact on the Company s consolidated financial position or results of operations.

25

California Price Reporting and Anti-Trust Litigation

As disclosed in previous filings with the SEC, the Company s subsidiary, Enserco, has ongoing litigation in the San Diego Superior Court, in the State of California, under the heading In re Natural Gas Anti-Trust Cases I, II, III, IV and V. The lawsuits have been pending against other marketers, traders, transporters and sellers of natural gas since as early as 2004. The plaintiffs allege the defendants, including Enserco, used various practices to manipulate natural gas prices in California in violation of the Cartwright Act and other California state laws. Enserco had filed motions to dismiss, which were pending before the court. On June 2, 2007, Enserco reached a settlement agreement set forth in a Letter of Intent. Final documentation is expected to be completed by the end of 2007. The Company has previously made accruals sufficient to cover the agreed upon settlement payment, the amount of which is not material to the Company s consolidated financial position, results of operations or cash flows.

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 2007.

(15) ACQUISITIONS

Aquila

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

The purchase is conditioned on the completion of the acquisition of the outstanding shares of Aquila by Great Plains immediately following the sale of the regulated utilities to the Company. The purchase is also subject to regulatory approvals from the Missouri Public Service Commission, the Kansas Corporation Commission, the Colorado Public Utilities Commission, the Nebraska Public Service Commission, the Iowa Utilities Board and FERC; Hart-Scott-Rodino antitrust review; as well as other customary conditions.

In conjunction with the asset acquisition, on May 7, 2007, the Company entered into a senior unsecured $1.0 billion Acquisition Facility to provide for funding for the Company s pending acquisition of Aquila assets. The Acquisition Facility is a committed facility to fund an acquisition term loan in a single draw in an amount of up to $1.0 billion. The commitment to fund the acquisition term loan terminates on August 5, 2008. Upon funding of the loan, the loan termination date is the earlier of the date which is 364 days from the loan funding date or February 5, 2009.

This transaction would add approximately 93,000 electric utility customers and 523,000 gas utility customers to the Company s utility operations.

The Company is capitalizing certain incremental acquisition costs incurred related to this pending acquisition. Amounts capitalized in the three and six month periods ended June 30, 2007 were approximately $5.1 million and $7.2 million, respectively.

26

(16) 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 (Loss) 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 Crude Oil Marketing and Transportation Assets

On March 1, 2006, the Company sold the operating assets of BHER and related subsidiaries, its crude oil marketing and transportation business, for approximately $41 million. Assets sold include the 200-mile Millennium and the 190-mile Kilgore Pipelines, oil marketing contracts and certain other ancillary assets. Following the sale, the Company closed the operations of the Houston, Texas based business. For business segment reporting purposes, BHER was included in the Energy marketing and transportation segment.

Revenues and net (loss) income from the discontinued operations were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Operating revenues	$	$ 36	$	$ 171,905
Pre-tax loss from discontinued operations (including severance payments)	$ (208)	$ (376)	$ (281)	$ (2,218)
Pre-tax (loss) gain on sale of assets		(558)		13,104
Income tax benefit (expense)	75	323	100	(3,907)
Net (loss) income from discontinued operations	$ (133)	$ (611)	$ (181)	$ 6,979

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

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 retail services and wholesale energy. We report our business groups in the following segments:

Business Group	Financial Segment
Retail services group	Electric utility Electric and gas utility
Wholesale energy group	Oil and gas Power generation Coal mining Energy marketing

Our retail services group consists of our electric and gas utilities segments. Our electric utility, Black Hills Power, generates, transmits and distributes electricity to an average of approximately 64,200 customers in South Dakota, Wyoming and Montana. Our electric and gas utility, Cheyenne Light, serves approximately 38,900 electric and 32,600 natural gas customers in Cheyenne, Wyoming and vicinity. Our wholesale 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 fuel products.

Pending Power Plant Project and Power Purchase Agreement

In April 2007, we entered into a power purchase agreement to provide electric power to Public Service Company of New Mexico, a regulated electric and natural gas utility subsidiary of PNM.

Under the terms of the agreement, we will provide the capacity and energy of a 149 MW, simple-cycle gas turbine generation facility to be located near Albuquerque, New Mexico. The project is expected to cost approximately $101 million, and has a commercial operation in-service date in June 2008. If the Company would fail to meet the June 2008 in-service date, significant penalties could be incurred under the delay damage provisions that are customary within agreements of this nature. The agreement is a customary tolling agreement, where we receive variable and fixed fees for the plant s availability and operation, and Public Service Company of New Mexico will be responsible for providing fuel for the operation. In addition, the agreement affords us favorable change of law and government impositions pass-throughs to Public Service Company of New Mexico. The duration of the power purchase agreement is 20 years. During the term of the agreement, Public Service Company of New Mexico is also provided an option to acquire a 50 percent equity interest in this project for a price equal to the fair market value at the time of the option exercise with a minimum price equal to book value.

On June 20, 2007, we purchased certain equipment and assets related to the Valencia project from Public Service Company of New Mexico. The assets included the power plant turbine, permits, land and other auxiliary equipment. The purchase price was approximately $40.6 million, paid through entering into a $30.0 million short-term promissory note, payable to Public Service Company of New Mexico in December 2007, and $10.6 million in cash.

Pending Acquisition of Assets from Aquila

On February 7, 2007, we entered into a definitive agreement with Aquila for the asset acquisition of Aquila s regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa. The purchase price of the assets is $940 million, subject to closing adjustments. In conjunction with this agreement, we have entered into a binding agreement with a group of lenders for a committed acquisition credit facility as a bridge financing for the transaction. The Acquisition Credit Facility was completed on May 7, 2007.

The purchase is conditioned on the completion of the acquisition of the outstanding shares of Aquila by Great Plains immediately following the sale of the regulated utilities to us. The purchase is also subject to regulatory approvals from the Missouri Public Service Commission, the Kansas Corporation Commission, the Colorado Public Utilities Commission, the Nebraska Public Service Commission, the Iowa Utilities Board and FERC; Hart-Scott-Rodino antitrust review; as well as other customary conditions. We have filed all necessary applications for the state and federal regulatory reviews and approvals required for the proposed transaction.

This transaction would add approximately 93,000 electric utility customers and 523,000 gas utility customers to our utility operations.

We are capitalizing certain incremental acquisition costs incurred related to this pending acquisition. Amounts capitalized in the three and six month periods ended June 30, 2007 were approximately $5.1 million and $7.2 million, respectively.

Disposition of Crude Oil Marketing and Transportation Business

In March 2006, we sold the operating assets of BHER and related subsidiaries, our crude oil marketing and pipeline transportation business headquartered in Houston, Texas. These activities were previously reported in our Energy marketing and transportation segment.

Results of Operations

Executive Summary

Results for the three and six month periods ended June 30, 2007 reflect increased earnings from all of our business segments. For the three month period ended June 30, 2007, net income was $25.1 million or $0.66 per share, compared to $11.8 million, or $0.35 per share, for the same period in 2006. Income from continuing operations for the three month period ended June 30, 2007 was $25.2 million, or $0.66 per share, compared to $12.4 million, or $0.37 per share, reported for the same period in 2006. For the six months ended June 30, 2007, net income was $57.6 million, or $1.56 per share, compared to $37.9 million, or $1.13 per share, reported for the same period in 2006. For the six months ended June 30, 2007, income from continuing operations was $57.7 million, or $1.57 per share, compared to $30.9 million, or $0.92 per share, reported for the same period in 2006.

Increased retail services earnings were driven by Black Hills Power benefiting from a 2007 South Dakota rate increase and having our Wyodak power plant in service compared to being under a planned maintenance outage in 2006. Cheyenne Light exhibited steady operations and benefited from the increased earnings impact of AFUDC related to the ongoing construction of Wygen II.

Earnings from the oil and gas operations increased for the quarter due to higher production on an equivalent basis from our San Juan and Powder River properties and some recent softening in overall industry costs. Year-to-date production is approximately 1 percent behind the prior year as a result of beginning 2007 with a 9 percent shortfall in the first quarter due to difficult winter conditions and production declines in the Denver-Julesburg Basin; while second quarter 2007 production was 4 percent over 2006 volumes for the period. Additionally, earnings were positively impacted by increased hedged natural gas and crude oil prices received compared to the prior year as well as income tax benefits resulting from amended income tax returns.

Increased earnings from power generation reflect increased plant availability compared to 2006, primarily due to the return to service of the Las Vegas facilities after scheduled and unscheduled maintenance in the first and second quarters of 2006. In addition, the power generation segment earnings benefited from lower interest expense associated with recent debt reductions.

Strong earnings from energy marketing reflect higher margins received and increased volumes. Through our transportation and other marketing strategies, we were able to take advantage of natural gas price volatility and basis differentials between the Rocky Mountain prices and other regions.

On February 22, 2007, we completed the issuance and sale of approximately 4.17 million shares of common stock at a price of $36.00 per share in a private placement to institutional investors pursuant to a Securities Purchase Agreement dated as of February 14, 2007. We used the net offering proceeds of $145.6 million for debt reduction. As a result of the use of a weighted average methodology to calculate the number of shares outstanding, the dilutive effect of the stock issuance will increase as the year progresses.

Consolidated Results

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Revenues				
Retail services	$ 66,039	$ 76,135	$ 149,758	$ 163,637
Wholesale energy	97,904	77,662	200,717	162,035
Corporate		16	1	32
	$ 163,943	$ 153,813	$ 350,476	$ 325,704
Income/(Loss) from Continuing Operations				
Retail services	$ 5,924	$ 3,300	$ 15,695	$ 9,596
Wholesale energy	20,126	9,453	42,970	24,597
Corporate	(819)	(385)	(933)	(3,264)
	$ 25,231	$ 12,368	$ 57,732	$ 30,929

Discontinued operations in 2007 and 2006 represent the operations of our crude oil marketing and transportation business. The assets of this business were sold in March 2006.

Three Months Ended June 30, 2007 Compared to Three Months Ended June 30, 2006. Revenues for the three months ended June 30, 2007 increased 7 percent, or $10.1 million, compared to the same period in 2006. Increased revenues were primarily driven by higher margins from our energy marketing activities, higher prices and volumes from our oil and gas operations and higher average price received and higher tons sold from our coal mining operations. These factors were partially offset by lower revenues at our retail services group due to the impact of cost recovery rate adjustments at Cheyenne Light and lower off-system sales at Black Hills Power.

Operating expenses decreased 2 percent, or $2.8 million, primarily due to lower fuel and purchased power costs and lower operating and maintenance cost at the electric and gas utility, partially offset by increased compensation expense and depreciation and depletion expense.

Income from continuing operations increased $12.9 million due primarily to the following:

- a $2.4 million increase in Electric utility earnings;
- a $0.2 million increase in Electric and gas utility earnings;
- a $2.3 million increase in Oil and gas earnings;
- a $4.7 million increase in Energy marketing earnings;
- a $3.1 million increase in Power generation earnings; and
- a $0.6 million increase in Coal mining earnings,

partially offset by:

- a $0.4 million increase in unallocated corporate costs.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006. Revenues for the six months ended June 30, 2007 increased 8 percent, or $24.8 million, compared to the same period in 2006. Increased revenues were primarily driven by higher margins from our energy marketing activities and improved revenues from Power generation. These factors were partially offset by lower revenues at our retail services group due to the impact of cost recovery rate adjustments at Cheyenne Light and lower off-system sales at Black Hills Power.

Operating expenses decreased 2 percent, or $4.7 million, primarily due to lower fuel and purchased power costs at the electric and gas utility, and lower operating and maintenance cost at Power generation due to the 2006 outages at the Las Vegas facility, partially offset by increased compensation expense and depreciation and depletion expense.

Income from continuing operations increased $26.8 million due primarily to the following:

- a $4.2 million increase in Electric utility earnings;
- a $1.9 million increase in Electric and gas utility earnings;
- a $0.5 million increase in Oil and gas earnings;
- a $11.1 million increase in Energy marketing earnings;
- a $5.9 million increase in Power generation earnings;
- a $0.8 million increase in Coal mining earnings; and
- a $2.3 million decrease in unallocated corporate costs.

See the following discussion of our business segments under the captions Retail Services Group and Wholesale Energy Group for more detail on our results of operations.

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

Retail Services Group

Electric Utility

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)			
Revenue	$ 44,972	$ 47,036	$ 92,739	$ 91,004
Operating expenses	34,912	40,545	70,134	74,416
Operating income	$ 10,060	$ 6,491	$ 22,605	$ 16,588
Income from continuing operations and net income	$ 4,881	$ 2,436	$ 11,580	$ 7,335

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	2007	Percentage Change	2006	2007	Percentage Change	2006
Commercial	$ 13,094	10%	$ 11,892	$ 26,193	12%	$ 23,290
Residential	9,667	9	8,868	22,079	13	19,556
Industrial	5,482	6	5,187	10,578	4	10,198
Municipal sales	647	9	591	1,226	10	1,111
Total retail sales	28,890	9	26,538	60,076	11	54,155
Contract wholesale	5,832	(1)	5,920	12,289	2	12,028
Wholesale off system	7,415	(30)	10,575	13,998	(26)	18,809
Total electric sales	42,137	(2)	43,033	86,363	2	84,992
Other revenue	2,835	(29)	4,003	6,376	6	6,012
Total revenue	$ 44,972	(4)%	$ 47,036	$ 92,739	2%	$ 91,004

Megawatt Hours Sold

	Three Months Ended June 30,			Six Months Ended June 30,		
Customer Base	2007	Percentage Change	2006	2007	Percentage Change	2006
Commercial	160,482	2%	158,046	326,576	3%	316,639
Residential	106,788	1	105,484	259,524	5	247,278
Industrial	110,004	2	108,333	209,258	(1)	211,360
Municipal sales	7,788	2	7,652	15,208	3	14,711
Total retail sales	385,062	1	379,515	810,566	3	789,988
Contract wholesale	151,828	(2)	154,694	316,938		316,945

Wholesale off system	150,363	(44)	268,174	284,212	(37)	448,337
Total electric sales	687,253	(14)	802,383	1,411,716	(9)	1,555,270

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Regulated power plant fleet availability:				
Coal-fired plants	93.9%	83.9%	94.6%	90.6%
Other plants	99.1%	99.5%	99.5%	99.4%
Total availability	96.2%	90.9%	96.8%	94.5%

	Three Months Ended June 30,			Six Months Ended June 30,		
Resources	2007	Percentage Change	2006	2007	Percentage Change	2006
MWhs generated:						
Coal	434,707	19%	366,821	875,225	7%	820,954
Gas	28,643	149	11,482	34,341	151	13,693
	463,350	22%	378,303	909,566	9%	834,647
MWhs purchased	254,588	(45)%	464,219	549,051	(29)%	776,506
Total resources	717,938	(15)%	842,522	1,458,617	(9)%	1,611,153

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Heating and cooling degree days:				
Actual				
Heating degree days	857	710	3,912	3,656
Cooling degree days	203	211	203	211
Percent of normal				
Heating degree days	86%	71%	91%	85%
Cooling degree days	201%	209%	201%	209%

Three Months Ended June 30, 2007 Compared to Three Months Ended June 30, 2006. Income from continuing operations increased $2.4 million primarily due to lower maintenance expenses compared to 2006, which included a planned maintenance outage of the Wyodak plant, and higher retail revenues in 2007 resulting from rate increases that went into effect January 1, 2007. These items were partially offset by higher allocated corporate costs and lower gross margin from off-system sales.

Total revenues decreased 4 percent for the three month period ended June 30, 2007, compared to the same period in the prior year. Wholesale off-system sales decreased 30 percent due to a 44 percent decrease in MWhs sold partially offset by a 25 percent increase in average price received. MWhs available for wholesale off-system sales decreased from the prior period due to storm damage related transmission constraints to the east of our AC-DC transmission tie and increased native load. Following transmission repairs, we were able to resume full utilization of the AC-DC tie in June 2007. Decreases in off-system sales were partially offset by higher revenues from retail sales resulting from the January 1, 2007 rate increase and a slight increase in MWhs sold.

Operating expenses decreased 14 percent for the three month period ended June 30, 2007, compared to the same period in the prior year. Fuel and purchased power costs decreased 19 percent primarily due to a 14 percent decrease in MWh resource requirements resulting from a significant decrease in off-system sales volumes and higher MWhs generated from our low-cost coal resources due to the availability of the Wyodak plant for the whole period, partially offset by higher per MWh cost for purchased power. Maintenance costs for the three month period ended June 30, 2007 also decreased compared to costs incurred for 2006.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006. Income from continuing operations increased $4.2 million primarily due to lower maintenance expenses compared to 2006, which included a planned maintenance outage of the Wyodak plant and higher retail revenues in 2007 resulting from rate increases that went into effect January 1, 2007. These items were partially offset by lower gross margin from off-system sales.

Revenues increased 2 percent for the six month period ended June 30, 2007, compared to the same period in the prior year. Higher retail revenues resulted from rate increases that went into effect January 1, 2007 and a 3 percent increase in MWhs sold, partially offset by wholesale off-system sales decreasing 26 percent due to a 37 percent decrease in MWhs sold partially offset by a 17 percent increase in average price received. MWhs available for wholesale off-system sales decreased from the prior period due to storm damage related transmission constraints to the east of our AC-DC transmission tie and increased native load. Following transmission repairs, we were able to resume full utilization of the AC-DC tie in June 2007.

Operating expenses decreased 6 percent for the six month period ended June 30, 2007, compared to the same period in the prior year. Fuel and purchased power costs decreased 8 percent, primarily due to a 9 percent decrease in MWh resource requirements resulting from a significant decrease in MWhs sold off-system and higher MWhs generated from our low-cost coal resources due to the increased availability of the Wyodak plant for the period, partially offset by higher per MWh cost for purchased power. Operating expense for the six months ended June 30, 2007 was also affected by decreased maintenance costs compared to costs incurred for 2006 scheduled outages and higher depreciation expense.

Electric and Gas Utility

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)			
Revenue	$ 21,652	$ 29,730	$ 58,015	$ 73,428
Purchased gas and electricity	15,480	23,427	44,069	59,603
Gross margin	6,172	6,303	13,946	13,825
Operating expenses	5,112	5,297	10,439	10,919
Operating income	$ 1,060	$ 1,006	$ 3,507	$ 2,906
Income from continuing operations and net income	$ 1,043	$ 864	$ 4,115	$ 2,261

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	2007	Percentage Change	2006	2007	Percentage Change	2006
Commercial	$ 1,837	4%	$ 1,769	$ 3,653	10%	$ 3,324
Residential	2,063	(2)	2,107	4,278	(2)	4,368
Industrial	84	(3)	87	168	(3)	174
Municipal	144	2	141	288	5	273
Total electric	4,128	1	4,104	8,387	3	8,139
Other	52	(60)	131	79	(65)	225
Total electric margins	$ 4,180	(1)%	$ 4,235	$ 8,466	1%	$ 8,364

Gas Margins
(in thousands)

	Three Months Ended June 30,			Six Months Ended June 30,		
Customer Base	2007	Percentage Change	2006	2007	Percentage Change	2006
Commercial	$ 472	1%	$ 469	$ 1,398	5%	$ 1,326
Residential	1,243	(1)	1,251	3,428	1	3,381
Industrial	85	(8)	92	250	(9)	276
Total gas	1,800	(1)	1,812	5,076	2	4,983
Other	192	(25)	256	404	(15)	478
Total gas margins	$ 1,992	(4)%	$ 2,068	$ 5,480	%	$ 5,461

	Three Months Ended June 30,			Six Months Ended June 30,		
	2007	Percentage Change	2006	2007	Percentage Change	2006
Electric sales - MWh	222,459	2%	218,795	464,289	3%	451,622
Gas sales - Dth	881,983	7%	823,868	2,851,568	6%	2,694,322

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Heating and cooling degree days:				
Actual				
Heating degree days	1,139	877	4,162	3,868
Cooling degree days	90	124	90	124
Percent of normal				
Heating degree days	92%	71%	95%	88%
Cooling degree days	214%	295%	214%	295%

36

Three Months Ended June 30, 2007 Compared to Three Months Ended June 30, 2006. Income from continuing operations increased $0.2 million for the three months ended June 30, 2007 compared to the three months ended June 30, 2006. The increase in income from continuing operations was impacted by income related to AFUDC attributable to the ongoing construction of the Wygen II power plant and a slight decrease in operating expenses, partially offset by a slight decrease in electric and gas gross margins.

Gross margin decreased 2 percent primarily due to lower revenues from customer late fees in 2007, compared to a period of collection challenges in 2006. We consider gross margin to be the most useful performance measure as fluctuations in cost of gas and electricity flow through to revenues through cost recovery rate adjustments.

Operating expenses decreased 3 percent primarily due to lower depreciation expense, benefit costs and bad debt provisions.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006. Income from continuing operations increased $1.9 million for the six months ended June 30, 2007 compared to the six months ended June 30, 2006. The increase in income from continuing operations was impacted by income related to AFUDC attributable to the ongoing construction of the Wygen II power plant, the related income tax benefit due to the nature of the AFUDC tax effects, and a 4 percent decrease in operating expenses compared to the same period in 2006.

Gross margin was flat for the six months ended June 30, 2007, compared to the same period in 2006. We consider gross margin to be the most useful performance measure as fluctuations in cost of gas and electricity flow through to revenues through cost recovery rate adjustments.

Operating expenses decreased 4 percent primarily due to lower depreciation expense, benefit costs and bad debt provisions.

Rate Increase Requested. During March 2007, Cheyenne Light filed a rate request with the WPSC. The filing requests general rate increases of $8.4 million for electric rates and $4.6 million for gas rates, based upon rates in place at December 31, 2006. The requested increases also include rate base additions for Wygen II and other capital investments necessary for the expansion and maintenance of both electric and gas distribution systems to accommodate population and energy growth.

Wholesale Energy Group

A discussion of results from our Wholesale Energy group s operating segments follows:

Oil and Gas

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)			
Revenue	$ 25,814	$ 21,313	$ 51,657	$ 46,550
Operating expenses	18,488	16,271	36,986	32,224
Operating income	$ 7,326	$ 5,042	$ 14,671	$ 14,326
Income from continuing operations and net income	$ 4,376	$ 2,042	$ 7,967	$ 7,432

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Fuel production:				
Bbls of oil sold	103,500	96,300	206,900	186,800
Mcf of natural gas sold	3,183,700	3,088,500	5,862,000	6,047,600
Mcf equivalent sales	3,804,700	3,666,300	7,103,400	7,168,400

Year-to-date production is approximately 1 percent behind 2006 as a result of beginning 2007 with a 9 percent shortfall in the first quarter due to difficult winter weather conditions and production declines in the Denver-Julesburg Basin. Second quarter 2007 production on an equivalent basis was 4 percent higher than the same period in 2006 due to higher production from our San Juan and Powder River Basin properties. As discussed earlier this year, we lowered our long-term production and reserve growth targets to a range of 4 to 6 percent annually, down from our December 31, 2006 annual growth estimate of 10 percent. We expect to be at the lower end of this range based on year-to-date and forecasted results.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Average price received*:				
Gas/Mcf**	$ 5.48	$ 5.19	$ 6.27	$ 6.07
Oil/Bbl	$ 58.26	$ 48.40	$ 55.45	$ 46.91
Depletion expense/Mcfe	$ 2.03	$ 1.77	$ 2.04	$ 1.70

* Net of hedges
** Exclusive of gas liquids

The following are summaries of LOE/Mcfe:

	Three Months Ended June 30, 2007			Three Months Ended June 30, 2006		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$ 0.76	$ 0.31	$ 1.07	$ 0.93	$ 0.43	$ 1.36
Colorado	1.21	0.67[(a)]	1.88	1.52	0.57	2.09
Wyoming	1.34		1.34	1.25		1.25
All other properties	0.51	0.08	0.59	0.70	0.12	0.82
All locations	$ 0.84	$ 0.20	$ 1.04	$ 0.94	$ 0.24	$ 1.18

	Six Months Ended June 30, 2007			Six Months Ended June 30, 2006		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$ 0.99	$ 0.37	$ 1.36	$ 1.02	$ 0.46	$ 1.48
Colorado	1.34	0.95[(a)]	2.29	1.45	0.43	1.88
Wyoming	1.22		1.22	1.17		1.17
All other properties	0.66	0.14	0.80	0.66	0.15	0.81
All locations	$ 0.97	$ 0.26	$ 1.23	$ 0.94	$ 0.25	$ 1.19

(a) Reflects the expenses associated with Colorado acquisitions completed in 2006 which included underutilized gathering, processing and compression assets. It is anticipated 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, 2007 Compared to Three Months Ended June 30, 2006. Income from continuing operations increased $2.3 million for the three months ended June 30, 2007 compared to the same period in 2006 due to increased revenues and approximately $1.0 million of recognized income tax benefits resulting from amended federal income tax returns, partially offset by a net $0.4 million after-tax impact primarily related to an accrual increase related to the settlement of an ongoing royalty audit, and a 14 percent increase in operating expenses.

Revenue increased 21 percent for the three months ended June 30, 2007 compared to the three months ended June 30, 2006. Gas production increased 3 percent and the average hedged gas price received increased 6 percent. Oil production increased 7 percent and average hedged oil price received increased 20 percent.

Total operating expenses increased 14 percent for the three month period ended June 30, 2007 primarily due to increased field service costs and depletion expense. Lease operating expense was down due to the effect of increased production volumes and property tax adjustments, partially offset by increased pumping and wellhead compression costs. The average depletion rate per Mcfe is a function of capitalized costs, projected future development costs and the related underlying reserves in the periods presented. The increased depletion rate per Mcfe in 2007 compared to 2006 is primarily due to increases in current year finding costs and higher estimated future development costs as well as the higher average cost of reserves acquired in 2006 transactions, and the impact of year-end 2006 negative reserve revisions.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006. Income from continuing operations increased $0.5 million for the six months ended June 30, 2007 compared to the same period in 2006 due to increased revenues and approximately $1.0 million of recognized income tax benefits resulting from amended federal income tax returns, partially offset by a net $0.4 million after-tax impact primarily related to an accrual increase related to the settlement of an ongoing royalty audit, and a 15 percent increase in operating expenses.

Revenue increased 11 percent for the six months ended June 30, 2007 compared to the six months ended June 30, 2006. Gas production decreased 3 percent and the average hedged gas price received increased 3 percent. Oil production increased 11 percent and average hedged oil price received increased 18 percent.

Total operating expenses increased 15 percent for the six month period ended June 30, 2007 primarily due to increased field service costs and depletion expense. The LOE per Mcfe sold (LOE/Mcfe) increased 3 percent due to changing property mix with the 2006 acquisitions and increased repair and weather-related costs incurred in 2007. Depletion expense per Mcfe increased 20 percent. The average depletion rate per Mcfe is a function of capitalized costs, projected future development costs and the related underlying reserves in the periods presented. The increased depletion rate is due to increases in current year finding costs and higher estimated future development costs as well as the higher average cost of reserves acquired in 2006 transactions, and the impact of year-end 2006 negative reserve revisions.

Power Generation

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)			
Revenue	$ 39,962	$ 38,697	$ 79,528	$ 72,290
Operating expenses	25,878	24,858	51,008	48,897
Operating income	$ 14,084	$ 13,839	$ 28,520	$ 23,393
Income from continuing operations and net income	$ 5,433	$ 2,379	$ 10,412	$ 4,471

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Contracted power plant fleet availability:				
Coal-fired plant	94.0%	94.7%	93.8%	94.4%
Other plants	98.6%	89.8%	98.7%	88.3%
Total availability	98.2%	90.2%	98.3%	88.9%

Three Months Ended June 30, 2007 Compared to Three Months Ended June 30, 2006. Income from continuing operations increased $3.1 million primarily due to higher revenues and lower interest costs, partially offset by a 4 percent increase in operating expenses.

Revenues in the second quarter of 2007 increased 3 percent compared to revenues in the second quarter of 2006, primarily due to the return of the Las Vegas facilities to normal operation levels. In 2006, the Las Vegas plants experienced scheduled and unscheduled repair outages. Las Vegas I returned to service on April 22, 2006, while the two Las Vegas II heat recovery units returned to service on June 13, 2006 and July 4, 2006.

Operating expenses for the three months ended June 30, 2007, increased 4 percent over the same period in the prior year. The increase in operating expenses primarily resulted from higher variable operating costs and increased fuel costs at the Las Vegas I plant partially offset by lower maintenance costs compared to costs incurred for repairs of the Las Vegas facilities in 2006.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006. Income from continuing operations increased $5.9 million primarily due to higher revenues and lower interest costs, partially offset by a 4 percent increase in operating expenses.

Revenues in the six month period ended June 30, 2007 increased 10 percent compared to 2006, primarily due to the return of the Las Vegas facilities to normal operation levels. In 2006, the Las Vegas plants experienced scheduled and unscheduled repair outages. Las Vegas I returned to service on April 22, 2006, while the two Las Vegas II heat recovery units returned to service on June 13, 2006 and July 4, 2006.

41

Operating expenses for the six months ended June 30, 2007, increased 4 percent from the same period in the prior year. The increase primarily resulted from higher variable operating costs at the Las Vegas plants partially offset by lower maintenance costs compared to costs incurred for repairs of the Las Vegas facilities in 2006.

Coal Mining

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)			
Revenue	$ 10,002	$ 6,767	$ 19,747	$ 16,038
Operating expenses	8,582	6,156	16,711	13,812
Operating income	$ 1,420	$ 611	$ 3,036	$ 2,226
Income from continuing operations and net income	$ 1,379	$ 768	$ 2,995	$ 2,183

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)			
Fuel production:				
Tons of coal sold	1,269	1,012	2,482	2,234

Three Months Ended June 30, 2007 Compared to Three Months Ended June 30, 2006.

Income from continuing operations from our Coal mining segment increased $0.6 million. Revenue increased 48 percent for the three month period ended June 30, 2007 compared to the same period in 2006 due to an increase in average price received and higher tons of coal sold resulting from a return to normal operations after the 2006 Wyodak plant outage. Operating expenses increased 39 percent during the three months ended June 30, 2007 primarily due to increased royalty expense and coal taxes associated with increased production, as well as higher equipment repair costs.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006.

Income from continuing operations from our Coal mining segment increased $0.8 million. Revenue increased 23 percent for the six month period ended June 30, 2007 compared to the same period in 2006 due to an increase in average price received and higher tons of coal sold resulting from a return to normal operations after the 2006 Wyodak plant outage. Operating expenses increased 21 percent during the six months ended June 30, 2007 primarily due to increased royalty expense and coal taxes associated with increased production, as well as higher equipment repair costs.

Energy Marketing

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)			
Revenue				
Realized gas marketing gross margin	$ 19,110	$ 10,069	$ 40,355	$ 25,625
Unrealized gas marketing gross margin	2,431	(278)	8,957	1,123
Realized oil marketing gross margin	1,390	831	2,107	831
Unrealized oil marketing gross margin	(22)	1,002	(72)	1,002
	22,909	11,624	51,347	28,581
Operating expenses	9,065	4,893	18,053	12,100
Operating income	$ 13,844	$ 6,731	$ 33,294	$ 16,481
Income from continuing operations and net income	$ 8,938	$ 4,264	$ 21,596	$ 10,511

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

		Three Months Ended June 30,		Six Months Ended June 30,	
		2007	2006	2007	2006
Natural gas physical sales	MMBtus	1,581,000	1,504,300	1,738,900	1,390,700
Crude oil physical sales	Bbls	10,803	8,945[(a)]	8,442	8,945[(a)]

[(a)] Daily oil volumes are calculated beginning May 1, 2006 to reflect the start of crude oil marketing by Enserco out of our Golden, Colorado offices.

Three Months Ended June 30, 2007 Compared to Three Months Ended June 30, 2006. Income from continuing operations increased $4.7 million due to increased realized marketing margins and increased unrealized marketing gains.

Realized gas marketing margins increased approximately $9.0 million over the prior year due to a 5 percent increase in natural gas volumes marketed, and an 86 percent increase in margin per MMBtu sold, driven by continued volatility in the natural gas markets, including volatile basis differentials between Rocky Mountain prices and other regions. Unrealized natural gas mark-to-market gains increased $2.7 million over unrealized natural gas mark-to-market losses for the same period in 2006. (For discussion of potential volatility in energy marketing earnings related to accounting treatment of certain hedging activities at our natural gas and oil marketing operations, see Trading Activities in Part 1, Item 3 of this Form 10-Q.) Results also reflect earnings from the addition of crude oil marketing to our Rocky Mountain region producer services. Operating expenses increased primarily due to increased compensation cost related to higher realized margins and an increase in the bad debt provision.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006. Income from continuing operations increased $11.1 million due to increased realized marketing margins and increased unrealized marketing gains.

Realized gas marketing margins increased approximately $14.7 million over the prior year due to a 25 percent increase in natural gas volumes marketed, and a 30 percent increase in margin per MMBtu sold, driven by continued volatility in the natural gas markets, including volatile basis differentials between Rocky Mountain prices and other regions. Unrealized natural gas mark-to-market gains increased $7.8 million over unrealized natural gas mark-to-market gains for the same period in 2006. (For discussion of potential volatility in energy marketing earnings related to accounting treatment of certain hedging activities at our natural gas and oil marketing operations, see Trading Activities in Part 1, Item 3 of this Form 10-Q.) Results also reflect earnings from the addition of crude oil marketing to our Rocky Mountain region producer services. Operating expenses increased primarily due to increased compensation cost related to higher realized margins.

Corporate

Three Months Ended June 30, 2007 Compared to Three Months Ended June 30, 2006. Increased unallocated costs in the three months ended June 30, 2007 compared to the same period in 2006 are primarily the result of integration-related costs for the pending Aquila asset acquisition. In addition to the expensed integration costs, the Company has capitalized approximately $5.1 million in costs related to this acquisition.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006. Decreased costs in the six months ended June 30, 2007, compared to the same period in 2006, are primarily the result of increased allocation of interest costs and the capitalization of approximately $7.2 million of acquisition costs related to the Aquila transaction compared to the expensing of development costs in the same period ended June 30, 2006 associated with our activities related to Northwestern Corporation. The Company is allocating all interest costs to the subsidiary level in 2007 as compared to the six months ended in 2006.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2006 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 2006 Annual Report on Form 10-K.

44

Liquidity and Capital Resources

Cash Flow Activities

During the six month period ended June 30, 2007, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on our common stock, to pay our scheduled long-term debt maturities and to fund a portion of our property, plant and equipment additions. We plan to fund future property and investment additions including our pending acquisition of certain electric and gas utility assets of Aquila and the construction costs of the 149 MW generation facility to be located near Albuquerque, New Mexico through a combination of new equity, mandatory convertible securities, unsecured debt at the holding company level and internally generated cash resources.

Cash flows from operations decreased $21.5 million for the six month period ended June 30, 2007 compared to the same period in the prior year as a $26.8 million increase in income from continuing operations was affected by the following:

A $25.6 million decrease in cash flows from working capital changes. This decrease primarily resulted from changes in net accounts receivable and accounts payable and a $29.6 million decrease in cash flows from sales or purchases 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 $9.2 million decrease in cash flows from the net change in derivative assets and liabilities, primarily from derivatives associated with normal operations of our gas and oil marketing business and related commodity price fluctuations.

During the six months ended June 30, 2007, we had cash outflows from investing activities of $112.2 million, which was primarily due to the following:

Cash outflows of $111.4 million for property, plant and equipment additions. In addition to expenditures for property, plant and equipment in the normal course of business, these outflows include approximately $34.0 million related to the construction of our Wygen II power plant, approximately $37.3 million in maintenance capital and development drilling of oil and gas properties, and $10.6 million paid to acquire certain assets related to the Valencia project, including the plant turbine, permits and other auxiliary equipment.

During the six months ended June 30, 2007, we had positive net cash flow from financing activities of $29.7 million, primarily due to cash proceeds of $148.7 million from the issuance of common stock, partially offset by a $61.5 million net payment on our credit facility, the payment of cash dividends on common stock, the call of our outstanding debt with GE Capital in the amount of $23.5 million, as well as payment of long-term debt maturities.

Dividends

Dividends paid on our common stock totaled $24.2 million during the six months ended June 30, 2007, or $0.68 per share. This reflects a 3 percent increase, as approved by our board of directors in January 2007, from the 2006 dividend level. 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

On February 22, 2007, we completed the issuance and sale of approximately 4.17 million shares of our common stock, par value $1.00 per share, at a sale price of $36.00 per share, in a private placement to institutional investors. Net proceeds of approximately $145.6 million were used for the repayment of debt.

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 2007. As of June 30, 2007, we had approximately $40.2 million of cash unrestricted for operations. Approximately $3.0 million of the cash balance at June 30, 2007 was restricted by subsidiary debt agreements that limit our subsidiaries ability to dividend cash to the parent company.

Our $400 million revolving credit facility expires on May 4, 2010. The cost of borrowings or letters of credit issued under the new 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 6.02 percent one-month borrowing rate as of June 30, 2007).

On March 13, 2007, we entered into a second amendment to our revolving credit facility. The second amendment (i) increased the limit for borrowings or other credit accommodations for the separate credit facility for our energy marketing subsidiary from $260 million to $300 million, (ii) increased the allowed total commitments under the facility without requiring amendment of the facility from $500 million to $600 million, (iii) effective with the acquisition of certain electric and gas utility assets from Aquila, will increase the recourse leverage ratio limit from 0.65 to 1.00 to 0.70 to 1.00 for the first year after completion of the Aquila asset acquisition, reverting to 0.65 to 1.00 thereafter, and (iv) allowed for other modifications to enable us to complete the Aquila asset acquisition.

Our revolving credit facility can be used to fund our working capital needs and for general corporate purposes. At June 30, 2007, we had borrowings of $84.0 million and $50.1 million of letters of credit issued. Available capacity remaining on our revolving credit facility was approximately $265.9 million at June 30, 2007.

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 unless no default or no event of default exists prior to, or would result, after giving effect to such action.

Our consolidated net worth was $970.1 million at June 30, 2007, which was approximately $259.0 million in excess of the net worth we were required to maintain under the credit facility. Our long-term debt ratio at June 30, 2007 was 32.6 percent, our total debt leverage (long-term debt and short-term debt) was 42.8 percent, our recourse leverage ratio was approximately 44.1 percent and our interest expense coverage ratio for the twelve month period ended June 30, 2007 was 6.55 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 and expires on May 9, 2009. At June 30, 2007, there were outstanding letters of credit issued under the facility of $178.9 million, with no borrowing balances outstanding on the facility.

Our corporate credit rating by Moody s was Baa3 during the first six months of 2007; the outlook is negative. Our corporate credit rating by S&P was BBB-; the outlook is stable.

On April 30, 2007, we called our outstanding debt with GE Capital in the amount of $23.5 million. In conjunction with this, we expensed less than $0.1 million in unamortized deferred finance costs. The associated payment guarantees provided by us were also terminated.

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 various other banks to provide for funding for our pending acquisition of Aquila s electric utility in Colorado and its gas utilities in Colorado, Kansas, Nebraska and Iowa. The Acquisition Facility is a committed facility to fund an acquisition term loan in a single draw in an amount of up to $1.0 billion. The commitment to fund the acquisition term loan terminates on August 5, 2008. Upon funding of the loan, the loan termination date is the earlier of the date which is 364 days from the loan funding date or February 5, 2009.

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

Permanent financing to replace the Acquisition Facility for funding of the acquisition of the Aquila assets, as well as permanent financing of the construction costs of our Valencia, New Mexico project, is expected to be provided through a combination of new equity, mandatory convertible securities, unsecured debt at the holding company level and internally generated cash resources. We intend to complete long-term debt financing for a portion of the construction costs of our Wygen II power plant through first mortgage bonds to be issued at Cheyenne Light. Our Wygen I project debt of $128.3 million matures in June 2008. We intend to refinance these maturities with other long-term debt prior to maturity.

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 2006 Annual Report on Form 10-K filed with the SEC.

Guarantees

During the six months ended June 30, 2007, we had the following changes to our guarantees:

Extinguished two guarantees totaling $24.2 million at December 31, 2006 related to the payment and performance under our GE Capital debt obligations. Our outstanding debt obligations with GE Capital were paid on April 30, 2007;

The $0.3 million guarantee for the payments of Black Hills Power under various transactions with Idaho Power Company expired on March 1, 2007;

The $3.0 million guarantee for the payments of Cheyenne Light under various transactions with Questar Energy Trading Company expired on March 31, 2007;

Issued a guarantee for obligations and damages, if any, due by Valencia under a power purchase agreement with Public Service Company of New Mexico for up to $12.0 million and expiring in 2028; and

Issued a guarantee for up to $7.0 million related to the obligations of Enserco under an agency agreement whereby Enserco provides services to structure up to $100.0 million of certain transactions involving the buying, selling, transportation and storage of natural gas on behalf of another energy company and which expires in 2008.

Capital Requirements

During the six months ended June 30, 2007, capital expenditures were approximately $162.5 million for property, plant and equipment additions, which includes approximately $51.1 million of accrued liabilities and short-term debt. We currently expect capital expenditures for the entire year 2007 to approximate $268.8 million including $81.5 million related to the 149 MW, simple-cycle gas turbine generating facility to be located near Albuquerque, New Mexico, but excluding the $940.0 million purchase price and related other costs for the pending acquisition of Aquila utility assets.

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

New Accounting Pronouncements

Other than the new pronouncements reported in our 2006 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 2006 Annual Report on Form 10-K and in Item 1A. of Part II of this Quarterly Report on Form 10-Q filed with the SEC, and the following:

Our ability to obtain adequate cost recovery for our retail utility operations through regulatory proceedings and receive favorable rulings in periodic applications to recover costs for fuel and purchased power in our regulated utilities;

Our ability to complete acquisitions for which definitive agreements have been executed;

Our ability to obtain regulatory approval of acquisitions which, even if approved, could impose financial and operating conditions or restrictions that could impact our expected results;

Our ability to successfully integrate and profitably operate any future acquisitions;

The amount and timing of capital deployment in new investment opportunities or for the repurchase of debt or stock;

Our ability to successfully maintain or improve our corporate credit rating;

Our ability to complete the 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 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, energy and commodity supply or volume, the cost and availability of transportation of commodities, and demand for our services, all of which can affect our earnings, liquidity position and the underlying value of our assets;

Our ability to effectively use derivative financial instruments to hedge commodity, currency exchange rate and interest rate risks;

Our ability to minimize defaults on amounts due from counterparties with respect to trading and other transactions;

The amount of collateral required to be posted from time to time in our transactions;

Changes in or compliance with laws and regulations, particularly those relating to taxation, safety and protection of the environment;

Changes in state laws or regulations that could cause us to curtail our independent power production;

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 our activity in energy trading contracts that meet the definition of a derivative under SFAS 133 and that were marked-to-market during the six months ended June 30, 2007 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2006	$ (1,454) [(a)]
Net cash settled during the period on positions that existed at December 31, 2006	5,579
Unrealized gain on new positions entered during the period and still existing at June 30, 2007	12,141
Realized loss on positions that existed at December 31, 2006 and were settled during the period	(4,323)
Unrealized loss on positions that existed at December 31, 2006 and still exist at June 30, 2007	(1,118)
Total fair value of energy marketing positions at June 30, 2007	$ 10,825 [(a)]

(a) The fair value of positions marked-to-market consists of derivative assets/liabilities and natural gas inventory that has been designated as a hedged item and marked-to-market as part of a fair value hedge, as follows (in thousands):

	June 30, 2007	March 31, 2007	December 31, 2006
Net derivative assets	$ 17,201	$ 5,029	$ 30,059
Fair value adjustment recorded in material, supplies and fuel	(6,376)	2,448	(31,513)
	$ 10,825	$ 7,477	$ (1,454)

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.

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

Source of Fair Value	Maturities Less than 1 year	1 2 years	Total Fair Value
Actively quoted (i.e., exchange-traded) prices	$ 9,777	$ (196)	$ 9,581
Prices provided by other external sources	1,334	(90)	1,244
Modeled			
Total	$ 11,111	$ (286)	$ 10,825

The following table presents a reconciliation of our June 30, 2007 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). In accordance with GAAP and industry practice, the Company includes a Liquidity Reserve in its GAAP marked-to-market fair value. This Liquidity Reserve accounts for the estimated impact of the bid/ask spread in a liquidation scenario under which the Company is forced to liquidate its forward book on the balance sheet date.

Fair value of our energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$ 10,825
Increase in fair value of inventory, storage and transportation positions that are part of our forward trading book, but that are not marked-to-market under GAAP	26,251
Fair value of all forward positions (Non-GAAP)	37,076
Liquidity Reserve included in GAAP marked-to-market fair value	1,991
Fair value of all forward positions excluding the Liquidity Reserve (Non-GAAP)	$ 39,067

There have been no material changes in market risk faced by us from those reported in our 2006 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 2006 Annual Report on Form 10-K, and Note 12 of our Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Activities Other Than Trading

The Company has entered into agreements to hedge a portion of its estimated 2007, 2008 and 2009 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	04/03/2006	Swap	04/07	10/07	5,000	$ 7.46
San Juan El Paso	06/02/2006	Swap	04/07	10/07	2,500	$ 7.20
CIG	07/28/2006	Swap	09/06	03/08	2,500	$ 7.60
CIG	07/31/2006	Swap	09/06	03/08	2,500	$ 7.85
San Juan El Paso	11/03/2006	Swap	04/07	10/07	5,000	$ 6.91
San Juan El Paso	11/03/2006	Swap	11/07	03/08	5,000	$ 7.86
San Juan El Paso	11/29/2006	Swap	04/07	10/07	500	$ 7.10
San Juan El Paso	11/29/2006	Swap	11/07	12/07	5,000	$ 7.82
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	$ 7.15
San Juan El Paso	04/26/2007	Swap	04/09	06/09	2,500	$ 7.21
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

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	07/29/2005	Swap	Calendar 2007	5,000	$ 61.00
NYMEX	08/04/2005	Swap	Calendar 2007	5,000	$ 62.00
NYMEX	01/04/2006	Swap	Calendar 2007	5,000	$ 65.00
NYMEX	04/03/2006	Put	Calendar 2007	5,000	$ 70.00
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

ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 as of June 30, 2007. Based on their evaluation, they have 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, 2007 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 18 in Item 8 of our 2006 Annual Report on Form 10-K and Note 14 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 14 is incorporated by reference into this item.

Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006 includes certain risk factors that could materially affect our business, financial condition or future results. Those Risk Factors have not materially changed except as set forth below:

Estimates of the quantity and value of our proved oil and gas reserves may change materially due to numerous uncertainties inherent in estimating oil and natural gas reserves.

There are many uncertainties inherent in estimating quantities of proved reserves and their values. The process of estimating oil and natural gas reserves requires interpretation of available technical data and various assumptions, including assumptions relating to economic factors. Significant inaccuracies in interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. The accuracy of reserve estimates is a function of the quality of available data, engineering and geological interpretations and judgment, and the assumptions used regarding quantities of recoverable oil and gas reserves and prices for oil and natural gas. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those assumed in our estimates. These variances may be significant. Any significant variance from the assumptions used could cause the actual quantity of our reserves, and future net cash flow to be materially different from our estimates. In addition, results of drilling, testing and production and changes in oil and natural gas prices after the date of the estimate may result in substantial upward or downward revisions.

In each of the last three years the estimated proved reserve additions achieved through drilling activity and acquisition have been partially offset by significant negative revisions to previous estimates of our proved developed and undeveloped oil and gas reserves. These downward revisions were 29.6 Bcfe, 21.6 Bcfe and 39.1 Bcfe for the 2006, 2005 and 2004 year-end reserve estimates, respectively. In addition to other factors, these negative revisions were primarily driven by the results of our ongoing drilling and completion activities in our East Blanco Field located in New Mexico. The operations and reserves of this property were initially acquired in a transaction completed in 2003. The revisions at the East Blanco Field were primarily attributed to lower than expected production results from drilling activities conducted to further delineate the boundaries of the field. The lower reserves from the delineation wells, in turn, prompted revisions to previous reserve estimates (proved undeveloped and proved non-producing) for properties offsetting the delineation wells drilled.

Financing our future growth plan or refinancing existing debt maturities could be impacted by negative capital market conditions.

Recently, domestic financial markets have experienced unusual volatility and uncertainty. While this condition has occurred most visibly within the subprime mortgage lending sector of the credit market, liquidity has tightened in overall domestic financial markets, including the

investment grade debt and equity capital markets. Consequently, there is greater uncertainty regarding our ability to attract financing on reasonable terms. Our ability to finance our pending acquisition of the Aquila utility properties and other new financings as well as our ability to refinance debt maturities could be adversely affected by the inability to secure permanent financing on reasonable terms, if at all.

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, 2007 April 30, 2007	2,212[1]	$ 38.78		
May 1, 2007 May 31, 2007	2,613[1]	$ 41.72		
June 1, 2007 June 30, 2007	256[2]	$ 41.38		
Total	5,081	$ 40.43		

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

(2) Shares acquired by a Rabbi Trust for the Outside Directors Stock Based Compensation Plan.

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

(a) The Annual Meeting of Shareholders was held on May 20, 2007.

(b) The following Directors were elected to serve until the Annual Meeting of Shareholders in 2010:

Jack W. Eugster
Gary L. Pechota
Thomas J. Zeller

Other Directors whose terms of office continue are:

David C. Ebertz
David R. Emery
John R. Howard
Kay S. Jorgensen
Stephen D. Newlin
Warren L. Robinson
John R. Vering

(c) Matters Voted Upon at the Meeting

1. Elected three Class I Directors to serve until the Annual Meeting of Shareholders in 2010.

Jack W. Eugster	
Votes For	28,836,209
Votes Withheld	691,530
Gary L. Pechota	
Votes For	28,778,136
Votes Withheld	749,603
Thomas J. Zeller	
Votes For	28,842,540
Votes Withheld	685,199

2. Ratified the appointment of Deloitte & Touche LLP to serve as Black Hills Corporation s independent auditors in 2007.

Votes For	29,087,294
Votes Against	357,123
Abstain	83,322
Broker Non-Votes	

58

Item 6. Exhibits

Exhibit 10.1*	Second Amendment to the Second Amended and Restated Credit Agreement effective May 11, 2007, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, documentation agent and collateral agent, BNP Paribas, U.S. Bank National Association, Societe Generale, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch (Incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed May 16, 2007).
Exhibit 10.2*	First Amendment to the Second Amended and Restated Credit Agreement effective November 30, 2006, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, documentation agent and collateral agent, BNP Paribas, U.S. Bank National Association, Societe Generale, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch (Incorporated by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed May 16, 2007).
Exhibit 10.3	Credit Agreement dated as of May 7, 2007 among Black Hills Corporation as Borrower, ABN AMRO Bank N.V., as administrative agent, sole bookrunner and co-arranger, BMO Capital Markets, as syndication agent and co-arranger, Credit Suisse Securities (USA) LLC, as syndication agent and co-arranger, Union Bank of California, N.A., as syndication agent and co-arranger, and the Financial Institutions party thereto, as Banks.
Exhibit 31.1	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 31.2	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 32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002.
Exhibit 32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002.

* Previously filed as part of the filing indicated and incorporated by reference herein.

BLACK HILLS CORPORATION

Signatures

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

BLACK HILLS CORPORATION

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

/s/ Mark T. Thies
Mark T. Thies, Executive Vice President and
Chief Financial Officer

Dated: August 9, 2007

EXHIBIT INDEX

Exhibit Number	Description
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