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 September 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 October 31, 2007
Common stock, $1.00 par value	37,759,152 shares

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GLOSSARY OF TERMS

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

AFUDC	Allowance for Funds Used During Construction
Aquila	Aquila, Inc.
Bbl	Barrel
Bcfe	One billion cubic feet equivalent
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
BHER	Black Hills Energy Resources, Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
Black Hills Energy	Black Hills Energy, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel & Power Company, a direct, wholly-owned subsidiary of the Company
Cheyenne Light Pension Plan	The Cheyenne Light, Fuel & Power Company Pension Plan
Dth	Dekatherm
Enserco	Enserco Energy Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
FASB	Financial Accounting Standards Board
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
GE Capital	General Electric Capital Corporation
Great Plains	Great Plains Energy Incorporated
Indeck	Indeck Capital, Inc.
IPP	Independent power production
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Las Vegas I	Las Vegas I gas-fired power plant
Las Vegas II	Las Vegas II gas-fired power plant
LVC	Las Vegas Cogeneration Limited Partnership, an indirect, wholly-owned subsidiary of Black Hills Energy, Inc.
Mcfe	One thousand cubic feet equivalent
MMBtu	One million British thermal units
Moody’s	Moody’s Investor Services, Inc.
Mw	Megawatt
Mwh	Megawatt-hour
Nevada Power	Nevada Power Company
PNM	PNM Resources, Inc.
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 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 September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands, except per share amounts)			
Operating revenues	$ 162,354	$ 157,608	$ 512,830	$ 483,312
Operating expenses:				
Fuel and purchased power	42,840	47,740	130,726	151,150
Operations and maintenance	21,942	16,490	63,220	60,566
Administrative and general	27,316	19,721	79,285	64,776
Depreciation, depletion and amortization	26,630	24,141	74,712	67,407
Taxes, other than income taxes	8,347	8,570	28,337	26,667
Impairment of long-lived assets	2,721	—	2,721	—
	129,796	116,662	379,001	370,566
Operating income	32,558	40,946	133,829	112,746
Other income (expense):				
Interest expense	(9,634)	(12,400)	(30,720)	(37,310)
Interest income	990	389	2,429	1,403
Allowance for funds used during construction – equity	811	—	3,851	—
Other income, net	67	106	413	517
	(7,766)	(11,905)	(24,027)	(35,390)
Income from continuing operations before equity in earnings of unconsolidated subsidiaries, minority interest and income taxes	24,792	29,041	109,802	77,356
Equity in earnings (loss) of unconsolidated subsidiaries	574	615	2,092	(16)
Minority interest	(97)	(95)	(285)	(273)
Income tax expense	(7,627)	(7,362)	(36,235)	(23,939)
Income from continuing operations	17,642	22,199	75,374	53,128
(Loss) income from discontinued operations, net of taxes	(178)	81	(358)	7,060
Net income	$ 17,464	$ 22,280	$ 75,016	$ 60,188
Weighted average common shares outstanding:				
Basic	37,643	33,187	36,810	33,157
Diluted	38,078	33,560	37,226	33,526
Earnings per share:				
Basic–				
Continuing operations	$ 0.47	$ 0.67	$ 2.05	$ 1.60
Discontinued operations	—	—	(0.01)	0.21
Total	$ 0.47	$ 0.67	$ 2.04	$ 1.81
Diluted–				
Continuing operations	$ 0.46	$ 0.66	$ 2.03	$ 1.59
Discontinued operations	—	—	(0.01)	0.21
Total	$ 0.46	$ 0.66	$ 2.02	$ 1.80
Dividends paid per share of common stock	$ 0.34	$ 0.33	$ 1.02	$ 0.99

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)

	September 30, 2007	December 31, 2006	September 30, 2006
		(in thousands, except share amounts)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 81,201	$ 36,939	$ 47,716
Restricted cash	5,394	2,004	—
Receivables (net of allowance for doubtful accounts of $5,259; $4,202 and $4,007, respectively)	238,662	263,109	195,571
Materials, supplies and fuel	92,625	92,560	91,490
Derivative assets	29,385	69,244	66,990
Income tax receivable	—	—	11,524
Other assets	11,795	9,221	7,830
Assets of discontinued operations	3,543	1,424	1,043
	462,605	474,501	422,164
Investments	23,886	23,808	23,709
Property, plant and equipment	2,430,975	2,242,396	2,180,639
Less accumulated depreciation and depletion	(652,701)	(596,029)	(574,925)
	1,778,274	1,646,367	1,605,714
Other assets:			
Derivative assets	3,420	2,871	3,197
Goodwill	30,171	30,563	30,563
Intangible assets (net of accumulated amortization of $27,363; $25,852 and $25,072, respectively)	21,777	24,429	25,209
Other	44,774	42,137	38,177
	100,142	100,000	97,146
	$ 2,364,907	$ 2,244,676	$ 2,148,733
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$ 202,014	$ 224,009	$ 181,255
Accrued liabilities	102,019	95,020	82,098
Derivative liabilities	24,904	24,041	18,937
Deferred income taxes	—	1,215	5,001
Notes payable	96,648	145,500	147,000
Current maturities of long-term debt	143,380	17,106	17,103
Accrued income taxes	17,620	19,561	—
Liabilities of discontinued operations	694	2,526	4,131
	587,279	528,978	455,525
Long-term debt, net of current maturities	466,137	628,340	632,295
Deferred credits and other liabilities:			
Deferred income taxes	191,451	174,332	170,286
Derivative liabilities	3,615	1,530	2,913
Other	143,786	116,297	101,819
	338,852	292,159	275,018
Minority interest in subsidiaries	5,075	5,158	5,198
Stockholders' equity:			
Common stock equity –			
Common stock $1 par value; 100,000,000 shares authorized; Issued 37,802,087; 33,404,902 and 33,330,841 shares, respectively	37,802	33,405	33,331
Additional paid-in capital	558,935	409,826	407,488
Retained earnings	386,869	348,245	338,420
Treasury stock at cost – 42,935; 35,700 and 34,720 shares, respectively	(1,219)	(920)	(883)
Accumulated other comprehensive (loss) income	(14,823)	(515)	2,341
	967,564	790,041	780,697
	$ 2,364,907	$ 2,244,676	$ 2,148,733

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)

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands)	
Operating activities:		
Net income	$ 75,016	$ 60,188
Loss (income) from discontinued operations, net of taxes	358	(7,060)
Income from continuing operations	75,374	53,128
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	74,712	67,407
Net change in derivative assets and liabilities	(4,911)	2,136
Deferred income taxes	10,008	32,042
Distributed earnings in associated companies	177	4,304
Allowance for funds used during construction – equity	(3,851)	—
Change in operating assets and liabilities:		
Materials, supplies and fuel	25,011	(6,389)
Accounts receivable and other current assets	21,099	59,005
Accounts payable and other current liabilities	4,662	(61,878)
Other operating activities	6,495	26,239
Net cash provided by operating activities of continuing operations	208,776	175,994
Net cash used in operating activities of discontinued operations	(3,045)	(1,583)
Net cash provided by operating activities	205,731	174,411
Investing activities:		
Property, plant and equipment additions	(159,788)	(153,820)
Proceeds from the sale of business operations	—	40,735
Payment for acquisition, net of cash acquired	—	(75,425)
Other investing activities	(3,004)	(454)
Net cash used in investing activities of continuing operations	(162,792)	(188,964)
Net cash provided by (used in) investing activities of discontinued operations	2,479	(575)
Net cash used in investing activities	(160,313)	(189,539)
Financing activities:		
Dividends paid	(37,068)	(32,954)
Common stock issued	149,860	3,560
(Decrease) increase in short-term borrowings, net	(78,000)	92,000
Long-term debt – issuances	—	90,000
Long-term debt – repayments	(35,929)	(122,566)
Other financing activities	(585)	(1,171)
Net cash (used in) provided by financing activities of continuing operations	(1,722)	28,869
Net cash (used in) provided by financing activities of discontinued operations	—	—
Net cash (used in) provided by financing activities	(1,722)	28,869
Increase in cash and cash equivalents	43,696	13,741
Cash and cash equivalents:		
Beginning of period	37,530(b)	34,198(d)
End of period	$ 81,226(a)	$ 47,939(c)
Supplemental disclosure of cash flow information:		
Non-cash investing and financing activities-		
Property, plant and equipment acquired with accrued liabilities or short-term debt	$ 56,274	$ 31,481
Cash paid during the period for-		
Interest (net of amounts capitalized)	$ 30,160	$ 35,317
Income taxes paid (net of amounts refunded)	$ 7,627	$ 12,806

(a) Includes insignificant September 30, 2007 cash balances included in assets of discontinued operations.
(b) Includes approximately $0.6 million at December 31, 2006 of cash included in the assets of discontinued operations.
(c) Includes approximately $0.2 million at September 30, 2006 of cash included in the assets of discontinued operations.
(d) 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.

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 September 30, 2007, December 31, 2006 and September 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 nine months ended September 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	September 30, 2007	December 31, 2006	September 30, 2006
Materials and supplies	$ 35,562	$ 31,946	$ 30,160
Fuel	7,401	9,663	9,387
Gas and oil held by Energy marketing*	49,662	50,951	51,943
Total materials, supplies and fuel	$ 92,625	$ 92,560	$ 91,490

* As of September 30, 2007, December 31, 2006 and September 30, 2006, market adjustments related to natural gas held by Energy marketing and recorded in inventory were $(6.5) million, $(31.5) million and $(29.8) million, respectively (see Note 13 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.

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 financing 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 revolving credit 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 nine months ended September 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 the Company's GE Capital debt obligations. The Company's 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;
- 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; and
- Extinguished a $10.0 million guarantee under the Las Vegas I Power Purchase and Sales Agreement on September 25, 2007.

(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 September 30, 2007	Three Months		Nine Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 17,642		$ 75,374	
Basic earnings	17,642	37,643	75,374	36,810
Dilutive effect of:				
Stock options	—	111	—	108
Estimated contingent shares issuable for prior acquisition	—	159	—	159
Others	—	165	—	149
Diluted earnings	$ 17,642	38,078	$ 75,374	37,226

Period ended September 30, 2006	Three Months		Nine Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 22,199		$ 53,128	
Basic earnings	22,199	33,187	53,128	33,157
Dilutive effect of:				
Stock options	—	91	—	85
Estimated contingent shares issuable for prior acquisition	—	158	—	158
Others	—	124	—	126
Diluted earnings	$ 22,199	33,560	$ 53,128	33,526

(7) COMPREHENSIVE INCOME

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

	Three Months Ended September 30, 2007		Three Months Ended September 30, 2006	
Net income	$	17,464	$	22,280
Other comprehensive income (loss), net of tax:				
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $3,558 and $(3,998), respectively)		(6,749)		7,425
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $1,296 and $132, respectively)		(2,406)		(246)
Comprehensive income	$	8,309	$	29,459

	Nine Months Ended September 30, 2007		Nine Months Ended September 30, 2006	
Net income	$	75,016	$	60,188
Other comprehensive income (loss), net of tax:				
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $3,419 and $(7,318), respectively)		(6,521)		12,587
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $4,012 and $242, respectively)		(7,787)		(416)
Comprehensive income	$	60,708	$	72,359

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

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Amount from Equity-method Investees	Total
As of September 30, 2007	$ (6,248)	$ (8,404)	$ (171)	$ (14,823)
As of December 31, 2006	$ 8,119	$ (8,404)	$ (230)	$ (515)
As of September 30, 2006	$ 5,495	$ (2,936)	$ (218)	$ 2,341

(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 recently received notification from the Internal Revenue Service that the 2004 and 2005 tax years will be examined. The Company continues to be 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 September 30, 2008.

Effective Tax Rate

The Company's effective tax rate differs from the federal statutory rate as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	35.0%	35.0%	35.0%	35.0%
State income tax	(0.1)	0.3	0.2	0.5
Percentage depletion in excess of cost	(1.3)	(1.5)	(0.9)	(1.3)
IRS exam tax adjustment*	—	(7.3)	—	(2.8)
Tax return true-up	(3.8)	(1.3)	(0.4)	(0.5)
Other	—	(0.3)	(1.9)	0.2
	30.0%	24.9%	32.0%	31.1%

* As a result of the settlement of an Internal Revenue Service (IRS) exam of the tax years 2001-2003 with respect to certain tax positions taken by the Company, a reduction to income tax expense of approximately $2.2 million was recorded in the third quarter of 2006.

(9) PROCEEDS RECEIVED ON INSURANCE CLAIMS

In late 2005 and the first half of 2006, the Company's Las Vegas II power plant experienced unplanned outages due to damage to three of its gas turbines and two of its steam turbines. The outages lasted approximately six months as repairs were made to the turbines. The Company has filed insurance claims for reimbursement of repair expenditures and business interruption losses in the amount of approximately $11.1 million. At September 30, 2006, the Company had provided for the receipt of insurance proceeds of approximately $4.3 million. Approximately $0.4 million was applied to reduce capitalized repair costs included in Property, plant and equipment on the accompanying Condensed Consolidated Balance Sheet and $2.2 million for repair costs and $1.7 million for business interruption were applied as a reduction to Operations and maintenance expense on the accompanying Condensed Consolidated Statement of Income. As of September 30, 2007, the Company continues to pursue additional reimbursement from the insurance carrier. The carrier asserts that certain deductibles, exclusions and limitations apply preventing any future claims reimbursements. There can be no assurance that the Company will obtain any additional recovery from the insurance carrier.

(10) 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 nine months ended September 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 nine months ended September 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.

- 156,250 stock options were exercised during the nine months ended September 30, 2007, at a weighted-average exercise price of $29.76 per share providing $4.6 million of proceeds to the Company.
- Total compensation expense recognized for all equity compensation plans for the three months ended September 30, 2007 and 2006 was $1.4 million and $0.1 million, respectively, and for the nine month periods ended September 30, 2007 and 2006 was $4.4 million and $1.8 million, respectively.

(11) 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 September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Service cost	$ 687	$ 649	$ 2,061	$ 1,947
Interest cost	1,129	1,041	3,387	3,123
Expected return on plan assets	(1,374)	(1,247)	(4,122)	(3,741)
Prior service cost	38	38	114	114
Net loss	127	227	381	681
Net periodic benefit cost	$ 607	$ 708	$ 1,821	$ 2,124

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 September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Service cost	$ 103	$ 87	$ 309	$ 261
Interest cost	289	270	867	810
Prior service cost	3	3	9	9
Net loss	178	199	534	597
Net periodic benefit cost	$ 573	$ 559	$ 1,719	$ 1,677

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 September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Service cost	$ 135	$ 164	$ 405	$ 492
Interest cost	207	203	621	609
Net transition obligation	15	38	45	114
Prior service cost	—	(6)	—	(18)
Net gain/loss	(4)	—	(12)	—
Net periodic benefit cost	$ 353	$ 399	$ 1,059	$ 1,197

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 the three month periods ended September 30, 2007 and 2006 and $0.2 million for the nine month periods ended September 30, 2007 and 2006.

(12) 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 September 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 –

- 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.

Wholesale Energy group –

- 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 power plants concentrated in Colorado, Nevada, Wyoming and California;
- Coal mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; and
- Energy marketing, which markets natural gas, crude oil and related services primarily in the western and central regions of the United States and Canada.

Segment information follows the same accounting policies as described in Note 20 of the Notes to Consolidated Financial Statements in the Company's 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):

Three Month Period Ended September 30, 2007	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Retail services:			
Electric utility	$ 51,129	$ 645	$ 5,781
Electric and gas utility	21,146	—	1,408
Wholesale energy:			
Oil and gas	24,291	—	1,979
Power generation	42,235	—	5,642
Coal mining	6,818	3,628	1,358
Energy marketing	13,873	—	2,290
Corporate	—	—	(816)
Inter-segment eliminations	—	(1,411)	—
Total	$ 159,492	$ 2,862	$ 17,642

Three Month Period Ended September 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Retail services:			
Electric utility	$ 52,467	$ 723	$ 5,764
Electric and gas utility	24,479	—	953
Wholesale energy:			
Oil and gas	22,969	—	3,006
Power generation	42,700	—	9,839
Coal mining	6,055	3,391	1,908
Energy marketing	6,327	—	2,091
Corporate	11	—	(1,362)
Inter-segment eliminations	—	(1,514)	—
Total	$ 155,008	$ 2,600	$ 22,199

Nine Month Period Ended September 30, 2007	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Retail services:			
Electric utility	$ 142,872	$ 1,641	$ 17,361
Electric and gas utility	79,161	—	5,523
Wholesale energy:			
Oil and gas	75,948	—	9,945
Power generation	121,763	—	16,055
Coal mining	19,458	10,734	4,353
Energy marketing	65,220	—	23,886
Corporate	—	—	(1,749)
Inter-segment eliminations	—	(3,967)	—
Total	$ 504,422	$ 8,408	$ 75,374

Nine Month Period Ended September 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Retail services:			
Electric utility	$ 142,676	$ 1,518	$ 13,099
Electric and gas utility	97,907	—	3,214
Wholesale energy:			
Oil and gas	69,519	—	10,439
Power generation	114,991	—	14,310
Coal mining	15,905	9,579	4,091
Energy marketing	34,907	—	12,602
Corporate	43	—	(4,627)
Inter-segment eliminations	—	(3,733)	—
Total	$ 475,948	$ 7,364	$ 53,128

During 2007, the Company added assets of approximately $43.7 million on the ongoing construction of the Wygen II power plant within the Electric and gas utility segment; approximately $51.8 million on maintenance capital and development drilling within the Oil and gas segment; approximately $9.6 million for development costs related to the Aquila asset acquisition; and approximately $48.6 million on assets related to the Valencia project in the 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.

(13) 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 September 30, 2007		Outstanding at December 31, 2006		Outstanding at September 30, 2006	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of MMBtus)						
Natural gas basis swaps purchased	150,499	27	138,111	22	146,331	16
Natural gas basis swaps sold	158,349	27	148,720	22	153,530	18
Natural gas fixed for float swaps purchased	51,958	25	38,239	16	44,600	18
Natural gas fixed for float swaps sold	70,379	25	59,061	15	58,248	6
Natural gas physical purchases	95,028	18	87,782	22	66,972	27
Natural gas physical sales	93,008	30	106,500	34	117,135	39
Natural gas options purchased	31,973	6	22,373	15	18,447	15
Natural gas options sold	31,539	6	22,373	15	18,447	15

	Outstanding at September 30, 2007		Outstanding at December 31, 2006		Outstanding at September 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	1,619	7	1,600	4	404[(a)]	1
Crude oil physical sales	1,370	5	1,367	7	404[(a)]	1
Crude oil swaps purchased	465	12	240	12	300	12
Crude oil swaps sold	465	12	240	12	300	12
(Dollars, in thousands)						
Canadian dollars purchased	$ 29,000	1	$ 44,000	1	$ 23,000	1
Canadian dollars sold	$ —	—	$ —	—	$ 1,000	2

(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 September 30, 2007, December 31, 2006 and September 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
September 30, 2007	$ 22,183	$ 1,196	$ 12,154	$ 1,293	$ 9,932
December 31, 2006	$ 53,728	$ 4	$ 23,296	$ 377	$ 30,059
September 30, 2006	$ 51,528	$ 1,629	$ 17,546	$ 1,873	$ 33,738

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 September 30, 2007, December 31, 2006 and September 30, 2006, the market adjustments recorded in inventory were $(6.5) million, $(31.5) million and $(29.8) million, respectively.

Activities Other Than Trading

Oil and Gas Exploration and Production

On September 30, 2007, December 31, 2006 and September 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)
September 30, 2007								
Crude oil swaps/options	465,000	1.00	$ 490	$ —	$ 1,995	$ 688	$ (2,683)	$ 490
Natural gas swaps	11,180,500	1.60	6,712	872	494	1,035	6,403	(348)
			$ 7,202	$ 872	$ 2,489	$ 1,723	$ 3,720	$ 142
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)
September 30, 2006								
Crude oil swaps	300,000	1.00	$ 456	$ —	$ 1,308	$ 282	$ (1,441)	$ 307
Natural gas swaps	6,765,000	1.50	13,231	1,116	—	—	14,347	—
			$ 13,687	$ 1,116	$ 1,308	$ 282	$ 12,906	$ 307

*crude in Bbls, gas in MMBtus

Based on September 30, 2007 market prices, a $4.1 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 September 30, 2007, December 31, 2006 and September 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
September 30, 2007								
Natural gas swaps	610,000	0.60	$ —	$ —	$ 172	$ —	$ (172)	$ —
December 31, 2006								
Natural gas swaps	380,000	0.25	$ 1,220	$ —	$ —	$ —	$ 878	$ 342
September 30, 2006								
Natural gas swaps	525,000	0.50	$ 1,634	$ —	$ —	$ —	$ 410	$ 1,224

*gas in MMBtus

Based on September 30, 2007 market prices, a loss of $0.2 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 September 30, 2007, December 31, 2006 and September 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 (Loss)/Income
September 30, 2007								
Interest rate swaps	$ 150,000	5.04%	9.00	$ —	$ 1,352	$ 666	$ 599	$ 87
December 31, 2006								
Interest rate swaps	$ 150,000	5.04%	9.75	$ 287	$ 867	$ 74	$ 978	$ 102
September 30, 2006								
Interest rate swaps	$ 100,000	5.09%	10.00	$ 141	$ 452	$ 83	$ 758	$ (248)

Based on September 30, 2007 market interest rates and balances, a loss of approximately $0.7 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

In addition to the interest rate swaps above, during the third quarter of 2007, the Company entered into forward starting interest rate swaps with a total notional amount of $250.0 million to hedge the risk of interest rate movement between the hedge dates and the expected pricing date for a portion of the Company's anticipated 2008 long-term debt financings. The swaps have a mandatory early termination date of June 30, 2008. As of September 30, 2007, the mark-to-market value was $(3.8) million. These swaps are designated as cash flow hedges and accordingly, any resulting gain or loss will be recorded in "Accumulated other comprehensive loss" on the Condensed Consolidated Balance Sheet and amortized into earnings as additional interest income or expense over the life of the related long-term financing.

On July 3, 2007, Cheyenne Light entered into a $110.0 million treasury lock to hedge a $110.0 million First Mortgage Bond offering expected to be completed in November 2007. As of September 30, 2007, the mark-to-market value was $(5.6) million. The treasury lock cash settled on October 15, 2007, the pricing date of the expected offering, and resulted in a $4.3 million payment to the counterparty. The treasury lock was treated as a cash flow hedge and accordingly, the resulting loss is carried in "Accumulated other comprehensive loss" on the Condensed Consolidated Balance Sheet and will be amortized over the life of the related bonds as additional interest expense.

(14) 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.

(15) 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 March 31, 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. During October 2007, the parties initiated negotiations for the resolution of this dispute and formally agreed to suspend the arbitration proceeding pending the completion of negotiations. While the Company cannot predict the final outcome of this action, it is not expected to have a material impact on the Company’s consolidated financial position or results of operations.

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.

FERC Compliance Investigation

Following an internal investigation of natural gas marketing activities conducted within the Wholesale energy group, the Company identified possible instances of noncompliance with regulatory requirements applicable to those activities. The Company has notified the staff of FERC of its findings. The Company has also evaluated recent public announcements of civil penalties ranging from $0.3 million to $7.0 million that have been levied against other companies for violations of FERC regulatory requirements. We believe we have adequately reserved for the estimated potential penalty that could be levied on the Company. Although the outcome of any legal or regulatory proceedings resulting from these matters cannot be predicted with any certainty, the final resolution of these matters could have a material impact on the consolidated net income of any particular period, but is not expected to have a material impact upon the Company's overall consolidated financial position.

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 nine months of 2007.

(16) 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. During October 2007, shareholder approvals of the merger were completed. 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. Thus far, the Company has obtained state regulatory approval for the transfer of ownership in Iowa and Nebraska. At the federal level, the FERC has approved the acquisition of the Colorado Electric operation, and antitrust clearance has been obtained from the Federal Trade Commission.

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 expires 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 at September 30, 2007 were approximately $9.6 million. In addition, the Company has expensed certain integration related costs of approximately $1.4 million and $3.1 million for the three and nine months ended September 30, 2007, respectively.

(17) IMPAIRMENT OF LONG-LIVED ASSETS

During September 2007, the Company assessed the recoverability of the carrying value of the Ontario power plant due to the pending thermal host contract expiration without a long-term extension. The carrying amount of the assets tested for impairment was $1.3 million. The assessment resulted in an impairment charge of $1.3 million, primarily for net property, plant and equipment and intangible assets. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by its estimated future discounted cash flows. In addition, $1.4 million has been accrued for contract termination and decommissioning costs. These charges are included as a component of "Operating expenses" on the accompanying Condensed Consolidated Statement of Income. Operating results from the Ontario plant are included in the Power generation segment.

(18) 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 September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Operating revenues	$ 67	$ 6	$ 67	$ 171,911
Pre-tax loss from discontinued operations (including severance payments)	$ (23)	$ (164)	$ (304)	$ (2,930)
Pre-tax gain on sale of assets	—	7	—	13,659
Income tax (expense) benefit	(75)	74	25	(3,833)
Net (loss) income from discontinued operations	$ (98)	$ (83)	$ (279)	$ 6,896

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 utility 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 and known as the "Valencia Project." The project is expected to cost approximately $101 million, and has a commercial operation in-service date of June 2008. If we 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 and maturing 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.

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. During October 2007, shareholder approvals of the merger were completed. 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. Thus far, we have obtained state regulatory approval for the transfer of ownership in Iowa and Nebraska. At the federal level, the FERC has approved our acquisition of the Colorado Electric operation, and antitrust clearance has been obtained from the Federal Trade Commission.

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 at September 30, 2007 were approximately $9.6 million. In addition, we expensed certain integration related costs of approximately $1.4 million and $3.1 million for the three and nine month periods ended September 30, 2007, respectively.

Strategic Review of Business Assets

As part of an ongoing evaluation of strategic alternatives to our current business mix, we recently announced that we have retained a financial advisor to assist us in evaluating strategic options for certain of our IPP facilities. This economic evaluation could result in potential divestiture of certain of our IPP plants located throughout the western United States, subject to approval by our Board of Directors.

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 months ended September 30, 2007 were lower than the same period of the prior year primarily due to lower earnings from the Wholesale energy business group. Results for the nine month period ended September 30, 2007 reflect increased earnings from both the Retail services and Wholesale energy business groups. For the three month period ended September 30, 2007, net income was $17.5 million or $0.46 per share, compared to $22.3 million, or $0.66 per share, for the same period in 2006. Income from continuing operations for the three month period ended September 30, 2007 was $17.6 million, or $0.46 per share, compared to $22.2 million, or $0.66 per share, reported for the same period in 2006. For the nine months ended September 30, 2007, net income was $75.0 million, or $2.02 per share, compared to $60.2 million, or $1.80 per share, reported for the same period in 2006. For the nine months ended September 30, 2007, income from continuing operations was $75.4 million, or $2.03 per share, compared to $53.1 million, or $1.59 per share, reported for the same period in 2006.

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.

Retail services earnings were affected by Black Hills Power benefiting from a 2007 South Dakota rate increase, lower margins from off-system sales and increased plant maintenance cost and corporate allocations. 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 decreased for the quarter driven by higher depletion expense partially offset by increased revenues. Third quarter 2007 production was 13 percent over third quarter 2006 volumes and average hedged oil prices increased 13 percent, offset by a 14 percent decrease in average hedged gas prices. Production year-to-date on a Mcfe basis is 4 percent above the prior year-to-date period despite beginning 2007 with a 9 percent shortfall in the first quarter due to difficult winter conditions and production declines in the Denver-Julesburg Basin.

Decreased earnings from power generation reflect an impairment and other related charges on the Ontario plant and the receipt in 2006 of insurance proceeds related to the Las Vegas II outages and a 2006 beneficial tax adjustment. Year-to-date results also reflect the return to service of the Las Vegas facilities after the scheduled and unscheduled maintenance in the first and second quarters of 2006 and lower interest expense associated with recent debt reductions.

Earnings from energy marketing reflect higher realized margins received and increased volumes partially offset by higher mark-to-market losses and increased administrative charges. Through our transportation and other marketing strategies, we were able to take advantage of continued basis differential volatility prevailing in the natural gas markets.

Consolidated Results

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Revenues				
Retail services	$ 72,275	$ 76,946	$ 222,033	$ 240,583
Wholesale energy	90,079	80,651	290,797	242,686
Corporate	—	11	—	43
	$ 162,354	$ 157,608	$ 512,830	$ 483,312
Income/(Loss) from Continuing Operations				
Retail services	$ 7,189	$ 6,717	$ 22,884	$ 16,313
Wholesale energy	11,269	16,844	54,239	41,442
Corporate	(816)	(1,362)	(1,749)	(4,627)
	$ 17,642	$ 22,199	$ 75,374	$ 53,128

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 September 30, 2007 Compared to Three Months Ended September 30, 2006. Revenues for the three months ended September 30, 2007 increased 3 percent, or $4.7 million, compared to the same period in 2006. Increased revenues were primarily driven by higher margins from our energy marketing activities, higher prices from oil sales and increased gas production from the Oil and gas segment 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 lower off-system sales at Black Hills Power and the impact of cost recovery rate adjustments at Cheyenne Light.

Operating expenses increased 11 percent, or $13.1 million, due to higher operations and maintenance cost as a result of higher mining costs related to increased coal production, impairment charges at our Ontario plant, increased compensation expense primarily due to higher realized marketing margins and higher depletion expense at our Oil and gas segment. Operating expenses for 2006 included receipt of an insurance settlement for reimbursement of repair costs for the Las Vegas II plant, which were presented as a reduction to operating expenses. These increased costs were partially offset by lower fuel and purchased power costs at the electric utility due to lower off-system sales and also the electric and gas utility, primarily reflecting cost recovery rate adjustments.

Income from continuing operations decreased $4.6 million due primarily to the following:

- a $1.0 million decrease in Oil and gas earnings;
- a $4.2 million decrease in Power generation earnings; and
- a $0.6 million decrease in Coal mining earnings,

partially offset by:

- a $0.5 million increase in Electric and gas utility earnings;
- a $0.2 million increase in Energy marketing earnings; and
- a $0.5 million decrease in unallocated corporate costs.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006. Revenues for the nine months ended September 30, 2007 increased 6 percent, or $29.5 million, compared to the same period in 2006. Increased revenues were primarily driven by higher margins from our energy marketing activities, higher average price received and higher tons sold from our coal mining operations and higher oil production and average price and increased gas production from the Oil and gas segment. 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.

Operating expenses increased 2 percent, or $8.4 million, primarily due to higher operating and maintenance cost at Power generation as a result of higher variable costs at the Las Vegas facility from a full year of operations, the 2006 receipt of insurance proceeds for the Las Vegas facility, increased compensation expense and depreciation and depletion expense, partially offset by lower fuel and purchased power costs at the electric utility due to lower off-system sales and also the electric and gas utility primarily reflecting lower cost recovery rate adjustments.

Income from continuing operations increased $22.2 million due primarily to the following:

- a $4.3 million increase in Electric utility earnings;
- a $2.3 million increase in Electric and gas utility earnings;
- an $11.3 million increase in Energy marketing earnings;
- a $1.7 million increase in Power generation earnings;
- a $0.3 million increase in Coal mining earnings; and
- a $2.9 million decrease in unallocated corporate costs;

partially offset by:

- a $0.5 million decrease in Oil and gas earnings.

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 September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands)			
Revenue	$ 51,774	$ 53,190	$ 144,513	$ 144,194
Operating expenses	40,626	40,423	110,760	114,839
Operating income	$ 11,148	$ 12,767	$ 33,753	$ 29,355
Income from continuing operations and net income	$ 5,781	$ 5,764	$ 17,361	$ 13,099

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

Electric Revenue
(in thousands)

	Three Months Ended September 30,			Nine Months Ended September 30,		
Customer Base	2007	Percentage Change	2006	2007	Percentage Change	2006
Commercial	$ 16,328	13%	$ 14,499	$ 42,502	13%	$ 37,766
Residential	12,564	15	10,886	34,662	14	30,465
Industrial	5,558	6	5,249	16,137	4	15,448
Municipal sales	808	11	731	2,033	10	1,842
Total retail sales	35,258	12	31,365	95,334	11	85,521
Contract wholesale	6,566	2	6,423	18,855	2	18,451
Wholesale off system	7,157	(43)	12,607	21,155	(33)	31,416
Total electric sales	48,981	(3)	50,395	135,344	—	135,388
Other revenue	2,793	—	2,795	9,169	4	8,806
Total revenue	$ 51,774	(3)%	$ 53,190	$ 144,513	—%	$ 144,194

Megawatt Hours Sold

Customer Base	Three Months Ended September 30, 2007	Percentage Change	2006	Nine Months Ended September 30, 2007	Percentage Change	2006
Commercial	199,239	4%	191,460	525,815	3%	508,099
Residential	136,297	7	127,100	395,820	6	374,378
Industrial	112,541	2	110,873	321,798	—	322,233
Municipal sales	10,681	3	10,365	25,890	3	25,076
Total retail sales	458,758	4	439,798	1,269,323	3	1,229,786
Contract wholesale	169,211	3	165,024	486,149	1	481,969
Wholesale off system	141,930	(48)	271,445	426,143	(41)	719,782
Total electric sales	769,899	(12)%	876,267	2,181,615	(10)%	2,431,537

Regulated Power Plant Fleet Availability

	Three Months Ended September 30, 2007	2006	Nine Months Ended September 30, 2007	2006
Coal-fired plants	95.0%	97.5%	94.7%	91.8%
Other plants	99.8%	99.8%	99.6%	99.6%
Total availability	97.2%	98.5%	96.9%	95.2%

Megawatt Hours Generated

Resources	Three Months Ended September 30, 2007	Percentage Change	2006	Nine Months Ended September 30, 2007	Percentage Change	2006
Coal	441,626	(1)%	445,984	1,316,851	4%	1,266,938
Gas	34,117	28	26,756	68,458	69	40,449
	475,743	1%	472,740	1,385,309	6%	1,307,387
Mwhs purchased	321,396	(24)%	424,209	870,447	(28)%	1,200,715
Total resources	797,139	(11)%	896,949	2,255,756	(10)%	2,508,102

Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Actual–				
Heating degree days	171	250	4,083	3,906
Cooling degree days	830	714	1,033	925
Percent of normal–				
Heating degree days	81%	110%	91%	86%
Cooling degree days	168%	145%	174%	155%

Three Months Ended September 30, 2007 Compared to Three Months Ended September 30, 2006. Income from continuing operations was flat with the prior period. Increased retail sales were offset by lower wholesale off-system sales. Increased plant maintenance costs, higher allocated corporate costs and lower gross margin from off-system sales due to limitations on arbitraged sales opportunities within the market also impacted current period results. In addition, 2006 results were negatively impacted by a $0.9 million income tax settlement expense.

Total revenues decreased 3 percent for the three month period ended September 30, 2007, compared to the same period in the prior year. Wholesale off-system sales decreased 43 percent due to a 48 percent decrease in Mwhs sold partially offset by a 9 percent increase in average price received. Lower revenues from wholesale off-system sales were partially offset by a 12 percent increase in retail sales, due to rate increases that went into effect January 1, 2007 and a 4 percent increase in Mwhs sold.

Operating expenses increased 1 percent for the three month period ended September 30, 2007, compared to the same period in the prior year. Fuel and purchased power costs decreased 7 percent primarily due to an 11 percent decrease in Mwh resource requirements resulting from the significant decrease in off-system sales volumes partially offset by a 14 percent increase in fuel costs for power generation. The decrease in fuel and purchased power costs was offset by increased operating expense primarily due to unscheduled plant maintenance costs and increased corporate allocations.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006. Income from continuing operations increased $4.3 million. Increased revenue due to increased retail sales and higher retail rates was offset by decreased off-system sales. Lower gross margins from off-system sales were due to limitations on arbitrage sales opportunities within the market. Lower expense was primarily attributable to lower purchase power expense, partially offset by higher operating expense. In addition, earnings were positively impacted by increased interest income and AFUDC.

Revenues increased $0.3 million for the nine month period ended September 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 33 percent reflecting a 41 percent decrease in Mwhs sold partially offset by a 14 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 4 percent for the nine month period ended September 30, 2007, compared to the same period in the prior year. Fuel and purchased power costs decreased 7 percent, primarily due to a 10 percent decrease in Mwh resource requirements resulting from a significant decrease in Mwhs sold off-system partially offset by higher Mwhs generated from our low-cost coal resources as a result of increased availability. Operating expense for the nine months ended September 30, 2007 was also affected by increased corporate allocations and depreciation expense partially offset by lower employee benefit costs and property taxes.

Electric and Gas Utility

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands)			
Revenue	$ 21,146	$ 24,479	$ 79,161	$ 97,907
Purchased gas and electricity	15,037	18,409	59,105	78,011
Gross margin	6,109	6,070	20,056	19,896
Operating expenses	4,692	5,047	15,132	15,967
Operating income	$ 1,417	$ 1,023	$ 4,924	$ 3,929
Income from continuing operations and net income	$ 1,408	$ 953	$ 5,523	$ 3,214

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

Electric Margins
(in thousands)

	Three Months Ended September 30,			Nine Months Ended September 30,		
Customer Base	2007	Percentage Change	2006	2007	Percentage Change	2006
Commercial	$ 1,989	3%	$ 1,926	$ 5,643	7%	$ 5,250
Residential	2,244	4	2,150	6,521	—	6,518
Industrial	84	(2)	86	252	(3)	260
Municipal	144	—	144	432	4	417
Total electric	4,461	4	4,306	12,848	3	12,445
Other	71	(32)	105	150	(55)	330
Total electric margins	$ 4,532	3%	$ 4,411	$ 12,998	2%	$ 12,775

Gas Margins
(in thousands)

Customer Base	Three Months Ended September 30, 2007	Percentage Change	2006	Nine Months Ended September 30, 2007	Percentage Change	2006
Commercial	$ 266	(3)%	$ 275	$ 1,664	4%	$ 1,601
Residential	1,116	(2)	1,134	4,544	1	4,516
Industrial	42	(35)	65	292	(14)	341
Total gas	1,424	(3)	1,474	6,500	1	6,458
Other	153	(17)	185	558	(16)	663
Total gas margins	$ 1,577	(5)%	$ 1,659	$ 7,058	(1)%	$ 7,121

	Three Months Ended September 30, 2007	Percentage Change	2006	Nine Months Ended September 30, 2007	Percentage Change	2006
Electric sales - Mwh	253,546	8%	234,104	717,835	5%	685,726
Gas sales - Dth	324,970	(13)%	374,994	3,176,538	3%	3,069,315

	Three Months Ended September 30, 2007	2006	Nine Months Ended September 30, 2007	2006
Heating and cooling degree days:				
Actual				
Heating degree days	205	369	4,367	4,237
Cooling degree days	446	362	536	486
Percent of normal				
Heating degree days	63%	113%	93%	90%
Cooling degree days	193%	157%	196%	178%

Three Months Ended September 30, 2007 Compared to Three Months Ended September 30, 2006. Income from continuing operations increased $0.5 million for the three months ended September 30, 2007 compared to the three months ended September 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 7 percent decrease in operating expense compared to the same period in 2006.

Gross margin increased 1 percent for the three months ended September 30, 2007 compared to the three months ended September 30, 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 7 percent primarily due to lower depreciation expense and bad debt provisions.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006. Income from continuing operations increased $2.3 million for the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006. The increase in income from continuing operations reflects income related to AFUDC attributable to the ongoing construction of the Wygen II power plant, and a 5 percent decrease in operating expenses compared to the same period in 2006.

Gross margin increased 1 percent for the nine months ended September 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 5 percent primarily due to lower depreciation expense 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. The WPSC held hearings in late October and we expect an order before the end of the year.

Wholesale Energy Group

An analysis of results from our Wholesale Energy group's operating segments follows:

<u>Oil and Gas</u>

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)			
Revenue	$ 24,291	$ 22,969	$ 75,948	$ 69,519
Operating expenses	19,813	16,524	56,799	48,748
Operating income	$ 4,478	$ 6,445	$ 19,149	$ 20,771
Income from continuing operations and net income	$ 1,979	$ 3,006	$ 9,945	$ 10,439

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Fuel production:				
Bbls of oil sold	100,923	109,146	307,816	295,942
Mcf of natural gas sold	3,285,222	2,784,080	9,147,245	8,831,697
Mcf equivalent sales	3,890,760	3,438,956	10,994,141	10,607,349

Year-to-date production is approximately 4 percent above 2006 despite 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. Third quarter 2007 production on an equivalent basis was 13 percent higher than the same period in 2006 due to higher production from our San Juan and Arkoma Basin properties. We have lowered our long-term production targets to a range of 2 to 4 percent annually, down from our December 31, 2006 annual growth estimate of 10 percent. We expect 2007 annual production growth over 2006 actual production of 14.4 Bcfe to also be within this range.

Average Price Received*

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Gas/Mcf**	$ 4.98	$ 5.82	$ 5.82	$ 5.99
Oil/Bbl	$ 62.51	$ 55.16	$ 58.82	$ 52.00
Depletion expense/Mcfe	$ 2.41	$ 1.95	$ 2.17	$ 1.78

* Net of hedge settlement gains/loss

** Exclusive of gas liquids

The following are summaries of LOE/Mcfe:

	Three Months Ended September 30, 2007			Three Months Ended September 30, 2006		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$ 0.99	$ 0.25	$ 1.24	$ 0.92	$ 0.31	$ 1.23
Colorado	0.40	0.48(a)	0.88	0.60	0.60	1.20
Wyoming	1.04	—	1.04	1.08	—	1.08
All other properties	1.09	0.40	1.49	0.79	0.19	0.98
All locations	$ 0.99	$ 0.23	$ 1.22	$ 0.92	$ 0.21	$ 1.13

	Nine Months Ended September 30, 2007			Nine Months Ended September 30, 2006		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$ 0.99	$ 0.33	$ 1.32	$ 0.98	$ 0.41	$ 1.39
Colorado	0.96	0.76[a]	1.72	1.04	0.51	1.55
Wyoming	1.15	—	1.15	1.14	—	1.14
All other properties	0.81	0.22	1.03	0.70	0.16	0.86
All locations	$ 0.98	$ 0.25	$ 1.23	$ 0.93	$ 0.24	$ 1.17

(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 September 30, 2007 Compared to Three Months Ended September 30, 2006. Income from continuing operations decreased $1.0 million for the three months ended September 30, 2007 compared to the same period in 2006 due to a 20 percent increase in operating expenses, partially offset by increased revenues.

Revenue increased 6 percent for the three months ended September 30, 2007 compared to the three months ended September 30, 2006. Gas production increased 18 percent and the average hedged gas price received decreased 14 percent. Oil production decreased 8 percent and average hedged oil price received increased 13 percent.

Total operating expenses increased 20 percent for the three month period ended September 30, 2007 primarily due to increased depletion expense. 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 and the impact of year-end 2006 negative reserve revisions.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006. Income from continuing operations decreased $0.5 million for the nine months ended September 30, 2007 compared to the same period in 2006 due to a 17 percent increase in operating expenses, partially offset by increased revenues and approximately $1.0 million of recognized income tax benefits resulting from amended federal income tax returns.

Revenue increased 9 percent for the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006. Gas production increased 4 percent and the average hedged gas price received decreased 3 percent. Oil production increased 4 percent and average hedged oil price received increased 13 percent.

Total operating expenses increased 17 percent for the nine month period ended September 30, 2007 primarily due to increased depletion expense. Depletion expense per Mcfe increased 22 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 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 impact of year-end 2006 negative reserve revisions.

Power Generation

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands)			
Revenue	$ 42,235	$ 42,700	$ 121,763	$ 114,991
Operating expenses	29,283	22,330	80,290	71,228
Operating income	$ 12,952	$ 20,370	$ 41,473	$ 43,763
Income from continuing operations and net income	$ 5,642	$ 9,839	$ 16,055	$ 14,310

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

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Contracted power plant fleet availability:				
Coal-fired plant	95.3%	96.1%	94.3%	95.0%
Other plants	98.4%	98.6%	98.6%	83.4%
Total availability	98.1%	98.3%	98.2%	92.0%

During September 2007, we assessed the recoverability of the carrying value of the Ontario plant due to the pending thermal host contract expiration without a long-term extension. The carrying amount of the assets tested for impairment was $1.3 million. The assessment resulted in an impairment charge of $1.3 million, primarily for net property, plant and equipment and intangible assets. These charges reflect the amount by which the carrying value of the facility exceeded its estimated fair value determined by its estimated future discounted cash flows. In addition, $1.4 million has been accrued for contract termination and decommissioning costs. These charges are included as a component of “Operating expenses” on the accompanying Condensed Consolidated Statement of Income.

Three Months Ended September 30, 2007 Compared to Three Months Ended September 30, 2006. Income from continuing operations decreased $4.2 million due to a 31 percent increase in operating expenses primarily due to impairment charges on the Ontario plant, the receipt of an insurance settlement which reduced 2006 operations and maintenance expense on the Las Vegas II plant, a slight decrease in revenues and a 2006 beneficial tax adjustment partially offset by lower interest costs.

Revenues in the third quarter of 2007 decreased 1 percent compared to revenues in the third quarter of 2006 primarily due to lower electric sales from the Harbor and Wygen plants.

Operating expenses for the three months ended September 30, 2007 increased 31 percent over the same period in the prior year. The increase in operating expenses primarily resulted from impairment of the Ontario plant and the 2006 impact of the receipt of an insurance settlement for reimbursement of repair costs at the Las Vegas II plant.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006. Income from continuing operations increased $1.7 million primarily due to higher revenues, a $1.9 million increase in equity income from subsidiaries, lower interest costs and a 2006 beneficial tax adjustment partially offset by a 13 percent increase in operating expenses, which includes an impairment and other related charges on the Ontario plant.

Revenues in the nine month period ended September 30, 2007 increased 6 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.

Operating expenses for the nine months ended September 30, 2007, increased 13 percent from the same period in the prior year. The increase in operating expenses primarily resulted from impairment of the Ontario plant and 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 September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)			
Revenue	$ 10,446	$ 9,446	$ 30,192	$ 25,484
Operating expenses	9,300	7,172	26,010	20,984
Operating income	$ 1,146	$ 2,274	$ 4,182	$ 4,500
Income from continuing operations and net income	$ 1,358	$ 1,908	$ 4,353	$ 4,091

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

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands)			
Fuel production:				
Tons of coal sold	1,314	1,244	3,796	3,479

Three Months Ended September 30, 2007 Compared to Three Months Ended September 30, 2006.
Income from continuing operations from our Coal mining segment decreased $0.6 million. Revenue increased 11 percent for the three month period ended September 30, 2007 compared to the same period in 2006 due to an increase in average price received and higher tons of coal sold. Operating expenses increased 30 percent during the three months ended September 30, 2007 primarily due to higher mining costs associated with higher production, increased overburden removal and increased compensation costs.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006.
Income from continuing operations from our Coal mining segment increased $0.3 million. Revenue increased 18 percent for the nine month period ended September 30, 2007 compared to the same period in 2006 due to an increase in average price received and higher tons of coal sold primarily resulting from a return to normal operations after the 2006 Wyodak plant outage. Operating expenses increased 24 percent during the nine months ended September 30, 2007 primarily due to higher mining costs associated with higher production and increased overburden removal, increased compensation costs and increased mineral taxes primarily due to higher production in 2007, and lower taxes in 2006 due to the filing of excise tax amendments.

Energy Marketing

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands)			
Revenue –				
Realized gas marketing gross margin	$ 17,661	$ 9,144	$ 58,016	$ 34,769
Unrealized gas marketing gross margin	(5,453)	(3,185	3,504	(2,062)
Realized oil marketing gross margin	1,615	1,126	3,722	1,957
Unrealized oil marketing gross margin	50	(758)	(22)	243
	13,873	6,327	65,220	34,907
Operating expenses	10,476	5,923	28,529	18,022
Operating income	$ 3,397	$ 404	$ 36,691	$ 16,885
Income from continuing operations and net income	$ 2,290	$ 2,091	$ 23,886	$ 12,602

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Natural gas physical sales – MMBtus	1,859,100	1,720,800	1,779,400	1,502,000
Crude oil physical sales – Bbls	10,200	9,200	9,000	9,100[(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 September 30, 2007 Compared to Three Months Ended September 30, 2006. Income from continuing operations increased $0.2 million due to increased realized marketing margins offset by increased unrealized gas marketing losses and higher operating expenses. In addition, 2006 reflected a $1.4 million positive impact on income tax expense related to the resolution of federal income tax audits.

Realized gas marketing margins increased approximately $8.5 million over the prior year due to an 8 percent increase in natural gas volumes marketed, and a 67 percent increase in margin per MMBtu sold, driven by continued volatility in the natural gas markets, including volatile regional price differentials. Unrealized natural gas mark-to-market losses increased $2.3 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.) Operating expenses increased primarily due to increased compensation cost related to higher realized margins and an increase in the bad debt provision.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006. Income from continuing operations increased $11.3 million due to increased realized marketing margins and increased unrealized marketing gains offset by higher operating expenses. In addition, a $1.4 million positive impact on income tax expense related to the resolution of federal income tax audits was recorded in 2006.

Realized gas marketing margins increased approximately $23.2 million over the prior year due to an 18 percent increase in natural gas volumes marketed, and a 50 percent increase in margin per MMBtu sold, driven by continued volatility in the natural gas markets, including volatile regional price differentials. Unrealized natural gas mark-to-market gains increased $5.6 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 for nine months in 2007 versus five months commencing May 2006. Operating expenses increased primarily due to increased compensation cost related to higher realized margins.

FERC Compliance Investigation

Following an internal investigation of natural gas marketing activities conducted within the Wholesale energy group, the Company identified possible instances of noncompliance with regulatory requirements applicable to those activities. The Company has notified the staff of FERC of its findings. We have also evaluated recent public announcements of civil penalties ranging from $0.3 million to $7.0 million that have been levied against other companies for violations of FERC regulatory requirements. We believe we have adequately reserved for the estimated potential penalty that could be levied on the Company. Although the outcome of any legal or regulatory proceedings resulting from these matters cannot be predicted with any certainty, the final resolution of these matters could have a material impact on the consolidated net income of any particular period, but is not expected to have a material impact upon the Company's overall consolidated financial position.

Corporate

Three Months Ended September 30, 2007 Compared to Three Months Ended September 30, 2006. Decreased unallocated costs in the three months ended September 30, 2007, compared to the same period in 2006, are primarily the result of receipt of funds for a litigation settlement partially offset by increased transitional and integration costs related to the pending purchase of certain Aquila assets.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006. Decreased unallocated costs in the nine months ended September 30, 2007, compared to the same period in 2006, are primarily the result of increased allocation of interest costs and receipt of funds for a litigation settlement partially offset by increased transitional and integration costs related to the pending purchase of certain Aquila assets. All interest costs are being allocated to the subsidiary level in 2007 as compared to the nine 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.

Liquidity and Capital Resources

Cash Flow Activities

During the nine month period ended September 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 Valencia 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 increased $31.3 million for the nine month period ended September 30, 2007 compared to the same period in the prior year as a $22.2 million increase in income from continuing operations was affected by the following:

- A $60.0 million increase in cash flows from working capital changes. This increase primarily resulted from changes in net accounts receivable and accounts payable and a $31.4 million increase in cash flows from a net sale of materials, supplies and fuel. This is primarily related to natural gas held in storage by our natural gas and crude oil marketing business which fluctuates based on economic decisions reflecting current market conditions.

- A $7.0 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.

- A $22.0 million decrease in cash flows related to changes in deferred income taxes which is primarily the result of the difference in federal tax return adjustments between the 2006 and 2005 tax years. These adjustments are primarily the result of accelerated deductions relating to property, plant and equipment, intangible drilling costs related to our Oil and gas segment and the timing of deductions related to deferred energy costs at our electric and gas utility.

- A $7.3 million increase in depreciation, depletion and amortization.

During the nine months ended September 30, 2007, we had cash outflows from investing activities of $160.3 million, which was primarily due to the following:

- Cash outflows of $159.8 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 $40.3 million related to the construction of our Wygen II power plant, approximately $51.8 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 nine months ended September 30, 2007, we had net cash outflow from financing activities of $1.7 million, primarily due to:

- A $78.0 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.

- Cash proceeds of $149.9 million from the issuance of common stock.

Dividends

Dividends paid on our common stock totaled $37.1 million during the nine months ended September 30, 2007, or $1.02 per share. This reflects a 3 percent increase, as approved by our board of directors in January 2007, from the 2006 dividend level.

On November 1, 2007, our Board of Directors increased the quarterly dividend by an additional 2.9 percent to $0.35 per share, equivalent to an annual dividend rate of $1.40 per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facility and our future business prospects.

Financing Transactions and Short-Term Liquidity

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 nine months of 2007. As of September 30, 2007, we had approximately $81.2 million of cash unrestricted for operations. Approximately $3.0 million of the cash balance at September 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 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 5.82 percent one-month borrowing rate as of September 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 on the separate credit facility for our energy marketing subsidiary from $260 million to $300 million, (ii) increased the allowed total commitments under the revolving credit 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 September 30, 2007, we had borrowings of $67.5 million and $50.1 million of letters of credit issued. Available capacity remaining on our revolving credit facility was approximately $282.4 million at September 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 $967.6 million at September 30, 2007, which was approximately $247.8 million in excess of the net worth we were required to maintain under the credit facility. Our long-term debt ratio at September 30, 2007 was 32.5 percent, our total debt leverage (long-term debt and short-term debt) was 42.2 percent, our recourse leverage ratio was approximately 43.3 percent and our interest expense coverage ratio for the twelve month period ended September 30, 2007 was 6.98 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, 2008. At September 30, 2007, there were outstanding letters of credit issued under the facility of $152.6 million, with no borrowing balances outstanding on the facility.

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

During June 2007, we 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.

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 by Cheyenne Light. Our Wygen I project debt of $128.3 million matures in June 2008. We intend to refinance this indebtedness with other long-term financings prior to maturity.

Cheyenne Light expects to complete a $110.0 million First Mortgage Bond private placement offering in November 2007. The bonds were priced on October 15, 2007. The offering is subject to closing conditions customary for this type of transaction.

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 nine months ended September 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 expiring in 2028;
- 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; and
- Extinguished a $10.0 million guarantee under the Las Vegas I Power Purchase and Sales Agreement on September 25, 2007.

Capital Requirements

During the nine months ended September 30, 2007, capital expenditures were approximately $216.1 million for property, plant and equipment additions, which were partially financed through approximately $56.3 million of accrued liabilities and short-term debt. We currently expect capital expenditures for the entire year 2007 to approximate $308 million including $81.5 million related to the Valencia 149 Mw, simple-cycle gas turbine generating facility located near Albuquerque, New Mexico, $55 million for the 90 Mw Wygen II power plant, which is expected to be in service January 1, 2008, $72 million for maintenance capital and development drilling within our Oil and gas segment, $20 million in development costs for the Wygen III generating facility and approximately $31 million of costs related to the pending acquisition of Aquila utility assets but excluding the $940 million purchase price and related other costs of the acquisition.

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, Item 1A. of Part II of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 and 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, and our ability to add power generation assets into regulatory rate base;
- 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 results of our evaluation of strategic alternatives that could change our business mix or asset size;
- 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, foreign exchange rates, energy and commodity supply or volume, the cost and availability of transportation of commodities, and demand for our services, all of which can affect our earnings, liquidity position and the underlying value of our assets;
- Our ability to effectively use derivative financial instruments to hedge commodity, currency exchange rate and interest rate risks;
- Our ability to minimize defaults on amounts due from counterparties with respect to trading and other transactions;
- The amount of collateral required to be posted from time to time in our transactions;
- Changes in or compliance with laws and regulations, particularly those relating to taxation, safety and protection of the environment;
- Changes in state laws or regulations that could cause us to curtail our 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 nine months ended September 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		11,695
Unrealized gain on new positions entered during the period and still existing at September 30, 2007		4,233
Realized loss on positions that existed at December 31, 2006 and were settled during the period		(7,745)
Unrealized loss on positions that existed at December 31, 2006 and still exist at September 30, 2007		(3,252)
Total fair value of energy marketing positions at September 30, 2007	$	3,477[(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):

	September 30, 2007	June 30, 2007	March 31, 2007	December 31, 2006
Net derivative assets	$ 9,932	$ 17,201	$ 5,029	$ 30,059
Fair value adjustment recorded in material, supplies and fuel	(6,455)	(6,376)	2,448	(31,513)
	$ 3,477	$ 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):

	Maturities		
Source of Fair Value	Less than 1 year	1 – 2 years	Total Fair Value
Actively quoted (i.e., exchange-traded) prices	$ 1,624	$ (321)	$ 1,303
Prices provided by other external sources	1,950	224	2,174
Modeled	—	—	—
Total	$ 3,574	$ (97)	$ 3,477

The following table presents a reconciliation of our September 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, we include a "Liquidity Reserve" in our 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 we are forced to liquidate our 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)	$ 3,477
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	48,750
Fair value of all forward positions (Non-GAAP)	52,227
"Liquidity Reserve" included in GAAP marked-to-market fair value	1,777
Fair value of all forward positions excluding the "Liquidity Reserve" (Non-GAAP)	$ 54,004

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 13 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	06/05/2006	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	$ 7.21
San Juan El Paso	04/26/2007	Swap	04/09 – 06/09	2,500	$ 7.15
San Juan El Paso	05/09/2007	Swap	04/09 – 06/09	5,000	$ 7.24
CIG	05/09/2007	Swap	04/09 – 06/09	2,000	$ 6.87
CIG	05/09/2007	Swap	01/09 – 03/09	2,000	$ 8.37
San Juan El Paso	07/27/2007	Swap	07/09 – 09/09	5,000	$ 7.63
CIG	09/07/2007	Swap	07/09 – 09/09	1,500	$ 6.48
CIG	09/07/2007	Swap	04/08 – 12/08	1,500	$ 5.91
AECO	09/07/2007	Swap	04/08 – 10/09	1,000	$ 6.89
San Juan El Paso	10/29/2007	Swap	07/09 – 09/09	5,000	$ 7.38
San Juan El Paso	10/29/2007	Swap	10/09 – 12/09	5,000	$ 7.53

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
NYMEX	09/12/2007	Swap	07/09 – 09/09	5,000	$ 71.20
NYMEX	09/12/2007	Put	01/09 – 03/09	5,000	$ 70.00
NYMEX	09/12/2007	Put	04/09 – 06/09	5,000	$ 70.00
NYMEX	10/29/2007	Put	10/09 – 12/09	5,000	$ 75.00
NYMEX	10/29/2007	Swap	10/09 – 12/09	5,000	$ 80.75

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 September 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 September 30, 2007 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Part II – Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 18 in Item 8 of our 2006 Annual Report on Form 10-K and Note 15 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 15 is incorporated by reference into this item.

Item 1A. Risk Factors

There have been no material changes in our Risk Factors from those reported in Item 1A. of Part I of our Annual Report on Form 10-K for the year ended December 31, 2006 and Item 1A. of Part II of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2007.

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

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2007 – July 31, 2007	127(1)	$ 40.85	—	—
August 1, 2007 – August 31, 2007	331(1)	$ 41.21	—	—
September 1, 2007 – September 30, 2007	267(2)	$ 42.00	—	—
Total	725	$ 41.47	—	—

(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) Thirteen shares acquired under the share withholding provisions of the Restricted Stock Plan as described in (1) above; and 254 shares acquired by a Rabbi Trust for the Outside Directors Stock Based Compensation Plan.

Item 6. Exhibits

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.

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: November 9, 2007

EXHIBIT INDEX

Exhibit Number	Description
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.
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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.

Exhibit 31.1

CERTIFICATION

I, David R. Emery, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: November 9, 2007

/s/ David R. Emery

Chairman, President and
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: November 9, 2007

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

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

In connection with the Quarterly Report of Black Hills Corporation (the “Company”) on Form 10-Q for the period ended September 30, 2007 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David R. Emery, Chairman, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: November 9, 2007

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

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

In connection with the Quarterly Report of Black Hills Corporation (the “Company”) on Form 10-Q for the period ended September 30, 2007 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Mark T. Thies, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: November 9, 2007

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