GeoMet, Inc.
Form 10-Q
November 09, 2007

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2007

OR

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

For the transition period from ______ to ______

Commission File Number 000-52155

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0662382**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

909 Fannin, Suite 1850

Houston, Texas 77010

(713) 659-3855

(Address of principal executive offices and telephone number, including area code)

N/A

(Former name, former address and former fiscal year, if changed since last report)

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. x Yes ¨ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ¨ Yes x No

As of November 1, 2007 there were 38,953,159 shares issued and outstanding of GeoMet, Inc. s common stock, par value $0.001 per share.

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Item 1. Financial Statements

GEOMET, INC. AND SUBSIDIARIES

Consolidated Balance Sheets

(Unaudited)

	September 30, 2007	December 31, 2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,892,123	$ 1,414,476
Accounts receivable	4,281,656	10,881,479
Current portion of notes receivable	57,019	81,181
Derivative asset	3,086,472	4,290,599
Other current assets	953,960	648,053
Total current assets	10,271,230	17,315,788
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	359,527,949	310,011,154
Unevaluated gas properties, not subject to amortization	23,967,560	26,397,982
Other property and equipment	2,535,810	2,314,190
Total property and equipment	386,031,319	338,723,326
Less accumulated depreciation, depletion, and amortization	(29,484,955)	(22,849,903)
Property and equipment net	356,546,364	315,873,423
Other noncurrent assets:		
Note receivable	278,458	298,936
Derivative asset		1,043,108
Other	517,820	663,511
Total other noncurrent assets	796,278	2,005,555
TOTAL ASSETS	$ 367,613,872	$ 335,194,766
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 8,667,784	$ 14,284,921
Accrued liabilities	3,497,603	2,917,575
Deferred income taxes	986,917	1,570,684
Asset retirement liability	81,328	73,047
Current portion of long-term debt	62,574	94,177
Total current liabilities	13,296,206	18,940,404
Long-term debt	89,284,726	60,832,110
Asset retirement liability	2,882,418	2,480,754
Other long-term accrued liabilities	146,616	154,455
Derivative liability	2,034	
Deferred income taxes	45,296,435	42,779,537

TOTAL LIABILITIES	150,908,435	125,187,260
Commitments and contingencies (Note 10)		
Stockholders Equity:		
Preferred stock, $0.001 par value authorized 10,000,000, none issued		
Common stock, $0.001 par value authorized 125,000,000 shares; issued and outstanding 38,953,159 and 38,678,713 at September 30, 2007 and December 31, 2006, respectively	38,953	38,679
Paid-in capital	187,392,501	186,852,852
Accumulated other comprehensive income (loss)	2,194,135	(193,888)
Retained earnings	27,300,993	23,740,144
Less notes receivable	(221,145)	(430,281)
TOTAL STOCKHOLDERS EQUITY	216,705,437	210,007,506
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 367,613,872	$ 335,194,766

See accompanying Notes to Consolidated Financial Statements.

GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Income

(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2007	**2006**	**2007**	**2006**
Revenues:				
Gas sales	$ 11,303,198	$ 10,916,708	$ 36,590,259	$ 33,367,653
Operating fees and other	341,099		957,098	
Total revenues	11,644,297	10,916,708	37,547,357	33,367,653
Expenses:				
Lease operating expense	3,559,786	2,509,874	10,353,430	8,183,527
Compression and transportation expense	1,165,745	1,040,660	4,033,311	3,172,298
Production taxes	260,125	259,915	857,806	764,852
Depreciation, depletion and amortization	2,346,875	2,168,456	6,687,649	5,748,942
Research and development	12,375	16,162	12,375	114,554
General and administrative	2,525,756	1,868,701	7,029,444	4,325,700
Realized (gains) losses on derivative contracts	(1,227,572)	(551,475)	(2,524,102)	(395,271)
Unrealized (gains) losses on derivative contracts	(463,960)	(4,134,128)	2,249,269	(14,578,784)
Total operating expenses	8,179,130	3,178,165	28,699,182	7,335,818
Income from continuing operations	3,465,167	7,738,543	8,848,175	26,031,835
Other income (expense):				
Interest income	6,893	6,938	31,991	25,151
Interest expense (net of amounts capitalized)	(1,448,065)	(738,501)	(3,583,481)	(2,367,640)
Other	(26,569)	(22,324)	(51,189)	(2,636)
Total other (expense) income	(1,467,741)	(753,887)	(3,602,679)	(2,345,125)
Income from continuing operations before income taxes	1,997,426	6,984,656	5,245,496	23,686,710
Income tax expense	453,973	2,757,127	1,850,159	10,004,863
Income from continuing operations	1,543,453	4,227,529	3,395,337	13,681,847
Discontinued operations:				
Discontinued operations, net of tax	44,618	12,164	165,512	12,164
Minority interest, net of tax		(12,164)		(12,164)
Income from discontinued operations	44,618		165,512	
Net income	$ 1,588,071	$ 4,227,529	$ 3,560,849	$ 13,681,847
Other comprehensive income, net of income taxes				
Foreign currency translation adjustment, net of income tax of $0	1,021,963	45,480	2,388,023	285,135
Comprehensive Income	$ 2,610,034	$ 4,273,009	$ 5,948,872	13,966,982
Earnings per Share:				
Income from continuing operations				

Basic	$	0.04	$	0.11	$	0.09	$	0.40
Diluted	$	0.04	$	0.11	$	0.09	$	0.39
Discontinued operations								
Basic	$		$		$		$	
Diluted	$		$		$		$	
Net income per common share								
Basic	$	0.04	$	0.11	$	0.09	$	0.40
Diluted	$	0.04	$	0.11	$	0.09	$	0.39
Weighted average number of common shares:								
Basic		38,726,595		36,921,141		38,706,546		33,799,293
Diluted		39,593,615		37,770,453		39,634,403		34,801,578

See accompanying Notes to Consolidated Financial Statements.

GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Nine Months Ended September 30, 2007	2006
Cash flows provided by operating activities:		
Net income	$ 3,560,849	$ 13,681,847
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	6,814,572	5,863,879
Amortization of debt issuance costs	105,475	99,920
Minority interest		12,164
Deferred income taxes	1,933,131	10,010,646
Unrealized losses (gains) from the change in market value of open derivative contracts	2,249,269	(14,578,784)
Stock-based compensation	257,393	287,376
Gain on sale of assets	(49,572)	(13,869)
Accretion expense	156,753	117,683
Changes in operating assets and liabilities:		
Accounts receivable	6,740,910	(1,282,731)
Other current assets	(305,907)	(418,662)
Accounts payable	(5,795,191)	7,059,955
Other accrued liabilities	572,049	474,458
Net cash provided by operating activities	16,239,731	21,313,882
Cash flows used in investing activities:		
Capital expenditures	(45,019,838)	(58,286,091)
Proceeds from sale of other property and equipment	97,855	(67,422)
Collection of notes receivable	44,640	140,410
Other assets	40,849	249,012
Net cash used in investing activities	(44,836,494)	(57,964,091)
Cash flows provided by financing activities:		
Debt issuance costs		(339,308)
Treasury stock	(4,382)	
Proceeds from exercise of stock options	198,808	1,010,962
Equity offering costs		(2,280,447)
Proceeds from sales of common stock		81,487,807
Credit facility borrowings	28,500,000	84,250,000
Proceeds from notes receivable and accrued interest	164,134	17,184,357
Payments on other debt	(78,987)	(142,322,661)
Net cash provided by financing activities	28,779,573	38,990,710
Effect of exchange rate changes on cash	294,837	(32,035)
Increase in cash and cash equivalents	477,647	2,308,466
Cash and cash equivalents at beginning of period	1,414,476	615,806
Cash and cash equivalents at end of period	$ 1,892,123	$ 2,924,272

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(Unaudited)

Note 1 Organization and Our Business

GeoMet, Inc. (GeoMet) (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. We are an independent natural gas producer primarily involved in the exploration, development and production of natural gas from coal seams (coal bed methane). Our principal operations and producing properties are located in Alabama, West Virginia, and Virginia.

The accompanying unaudited consolidated financial statements include our accounts and those of our wholly owned subsidiaries. All significant intercompany transactions and balances have been eliminated in consolidation. The unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to present fairly the financial position as of, and results of operations for, the interim periods presented. These financial statements have been prepared in accordance with the guidelines of interim reporting; therefore, they do not include all disclosures required for year-end financial statements prepared in conformity with accounting principles generally accepted in the United States of America. Interim period results are not necessarily indicative of results of operations or cash flows for the full year. These unaudited consolidated financial statements included herein should be read in conjunction with the audited financial statements for the fiscal year ended December 31, 2006 and the accompanying notes included in our Annual Report on Form 10-K, which we filed with the Securities and Exchange Commission (the SEC) on March 20, 2007.

Certain reclassifications have been made to the unaudited consolidated financial statements for the three and nine months ended September 30, 2006 to conform to the presentation for the three and nine months ended September 30, 2007.

On January 1, 2007, we exercised our purchase option and acquired 100% of Shamrock Energy LLC, our gas marketing subsidiary. In return, we provided Jon M. Gipson, the former owner of Shamrock, an at-will employment position with us. Also, pursuant to the terms of our purchase option, on March 9, 2007, we caused Shamrock to distribute to Mr. Gipson approximately $22,500, which equals 50% of the net profits generated by Shamrock from August 1, 2006 through January 1, 2007. This amount was accrued at December 31, 2006 as a dividend payable to Mr. Gipson. No additional consideration was paid as a result of our exercise of this purchase option. Over 99% of the net assets acquired were current, approximated their fair value and were equal to zero. Shamrock Energy LLC is a low margin business and as a result it does not have a significant impact on our results of operations. The acquisition was accounted for as a purchase in accordance with SFAS No. 141, Business Combinations, whereby the purchase price of the net assets acquired was allocated to those net assets based on their fair value. Goodwill was not recorded because the purchase price approximated the fair value of the net assets acquired.

Note 2 Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation Number (FIN) 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. This interpretation addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures. We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we identified $269,900 of unrecognized tax benefits, largely related to depletion methods used in years prior to 2006 from net deferred tax assets. There was no cumulative effect adjustment to retained earnings, financial condition or results of operations as a result of implementing FIN 48. For additional information see Note 12.

In September 2006, the FASB issued FASB Statement No. 157, *Fair Value Measurements* (FASB 157). FASB 157 establishes a single authoritative definition of fair values, sets out a framework for measuring fair values and requires additional disclosures about fair value measurements. FASB 157 applies only to fair value measurements that are already required or permitted by other accounting standards. FASB 157 is effective for fiscal years beginning after November 15, 2007. We do not expect FASB 157 to have a material impact on our consolidated financial position or results of operations upon adoption.

On February 15, 2007, the FASB issued FASB Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB 115, (FASB 159). This standard permits an entity to measure financial instruments and certain other items at estimated fair value. Most of the provisions of FASB 159 are elective; however, the amendment to FASB 115, Accounting for Certain Investments in Debt and Equity Securities, applies to all entities that own trading and available-for-sale securities. The fair value option created by FASB 159 permits an entity to measure eligible items at fair value as of specified election dates. The fair value option (a) may generally be applied instrument by instrument, (b) is irrevocable unless a new election date occurs, and (c) must be applied to the entire instrument and not to only a portion of the instrument. FASB 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity (i) makes that choice in the first 120 days of that year, (ii) has not yet issued financial statements for any interim period of such year, and (iii) elects to apply the provisions of FASB 157, Fair Value Measurements. Management is currently evaluating the impact of FASB 159, if any, on our financial statements.

Note 3 Earnings Per Share

Earnings Per Share of Common Stock Basic earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. Fully diluted earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Dilutive earnings per share consider the impact of potentially dilutive securities except in periods in which there is a loss because the inclusion of the potential common shares would have an anti-dilutive effect. A reconciliation of the numerator and denominator is as follows:

	Three Months Ended		Nine Months Ended	
	September 30,			
	2007	2006	2007	2006
Income from continuing operations:				
Basic-net income per share	$ 0.04	$ 0.11	$ 0.09	$ 0.40
Diluted-net income per share	$ 0.04	$ 0.11	$ 0.09	$ 0.39
Discontinued operations				
Basic-net income per share	$	$	$	$
Diluted-net income per share	$	$	$	$
Net income per share:				
Basic-net income per share	$ 0.04	$ 0.11	$ 0.09	$ 0.40
Diluted-net income per share	$ 0.04	$ 0.11	$ 0.09	$ 0.39
Numerator				
Income from continuing operations	$ 1,543,453	$ 4,227,529	$ 3,395,337	$ 13,681,847
Discontinued operations, net of minority interest	$ 44,618	$	$ 165,512	$
Net income available to common stockholders	$ 1,588,071	$ 4,227,529	$ 3,560,849	$ 13,681,847
Denominator:				
Weighted average shares outstanding-basic	38,726,595	36,921,141	38,706,546	33,799,293
Add potentially dilutive securities:				
Stock options and restricted stock	867,020	849,312	927,857	1,002,285
Weighted average shares and potential dilutive shares outstanding	39,593,615	37,770,453	39,634,403	34,801,578

Note 4 Gas Properties

We use the full cost method of accounting for our investment in gas properties. Under this method of accounting, all costs of acquisition, exploration and development of gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs related to unsuccessful projects, tangible and intangible development costs) are included in the full cost pool. In addition, we capitalize interest expense, and direct general and administrative expenses. Also under full cost accounting rules, total net capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation using natural gas prices in effect as of the balance sheet date as adjusted for basis or location differential, held constant over the life of the reserves. To the extent that capitalized costs of gas properties, net of accumulated depreciation, depletion and amortization and income taxes, exceed the ceiling limitation, such excess capitalized

costs would be charged to results of operations. During the nine months ended September 30, 2007 there were no charges to results of operations due to the ceiling limitation. We also perform a quarterly impairment test on our unevaluated properties. During the nine months ended September 30, 2007, we recorded an impairment of $6.0 million related to certain prospects located in North Central Louisiana and such impairment was added to our full cost pool.

Note 5 Asset Retirement Liability

We record an asset retirement obligation (ARO) on the consolidated balance sheet and capitalize the asset retirement costs in gas properties in the period in which the retirement obligation is incurred. The amount of the ARO and the costs capitalized are equal to the estimated future costs to satisfy the obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date we incurred the abandonment obligation using an assumed interest rate. Once the ARO is recorded, it is then accreted to its estimated future value using the same assumed interest rate.

The following table details the changes to our asset retirement liability for the nine months ended September 30, 2007:

Asset retirement obligation at beginning of year	$ 2,553,801
Liabilities incurred	200,051
Liabilities settled	
Accretion	179,872
Revisions in estimates	
Foreign currency translation	30,022
Asset retirement obligation at end of period	2,963,746
Less: Current portion of obligation	81,328
Long-term asset retirement obligation	$ 2,882,418

Note 6 Price Risk Management Activities

We engage in price risk management activities from time to time. These activities are designed to manage our exposure to fluctuations in the price of natural gas. We utilize derivative financial instruments, primarily three-way collars, traditional collars and swaps, as the means to manage this price risk. Under the collar arrangements, if the index price rises above the ceiling price, we pay the counterparty the difference between the index price and the ceiling price. If the index price falls below the floor price, the counterparty pays us the difference between the index price and the floor price. In the case of three-way collars, the obligation of the counterparty to pay the difference between the index price and the floor price is limited to the higher floor price (a bought put) and a lower floor price (a sold put).

We account for our derivative contracts as accounting hedges using mark-to-market accounting under FASB 133, *Accounting for Derivative Instruments and Hedging Activities.* During the three and nine months ended September 30, 2007, we recognized gains of $1.7 million and $0.3 million including realized gains of $1.2 and $2.5 million, respectively. During the three and nine months ended September 30, 2006, we recognized gains on derivative contracts of $4.7 million and $15.0 million including realized gains of $551,475 and $395,271, respectively.

At September 30, 2007 and at December 31, 2006, the fair values of open net derivative contracts assets were approximately $3.1 and $5.3 million, respectively.

As of September 30, 2007, the following natural gas derivative contracts were outstanding with prices expressed in dollars per million British thermal units ($/MMBtu) and notional volumes in million British thermal units. For our natural gas derivative contracts, summer months apply to April through October and winter months apply to November through March.

	Production Period	**Volumes**	**Collars**	
Instrument Type		**(MMBtu)**	**Weighted**	**Weighted**
			Average	**Average**

			Floor Prices ($/MMBtu)	Cap Prices ($/MMBtu)
Collars (3 way)	October 2007	248,000	$ 5.75-$7.38	$ 10.50
Traditional Collars	October 2007	124,000	$ 7.50	$ 9.75
Collars (3 way)	Winter 2007/2008	1,216,000	$ 6.00-$9.00	$ 14.80
Traditional Collars	Winter 2007/2008	608,000	$ 8.25	$ 11.25
Collars (3 way)	Summer 2008	1,712,000	$ 5.00-$7.00	$ 10.50

Note 7 Long-Term Debt

The following is a summary of our long-term debt at September 30, 2007 and December 31, 2006:

	September 30, 2007	December 31, 2006
Borrowings under bank credit facility	$ 88,500,000	$ 60,000,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	174,570	210,227
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	131,536	138,308
Salary continuation payable to an individual, semi-monthly installments of $3,958, through December 2015, non-interest-bearing (less amortization discount of $572,074, with an effective rate of 8.25%), unsecured	541,194	577,752
Total debt	89,347,300	60,926,287
Less current maturities included in current liabilities	(62,574)	(94,177)
Total long-term debt	$ 89,284,726	$ 60,832,110

We initially entered into a bank credit facility in December 2001. In January 2006, we amended and restated the bank credit facility and, among other things, extended the maturity date to January 6, 2011. In June 2006, the revolving credit facility was amended and restated and increased to $180 million and the borrowing base was increased to $150 million. Pursuant to the amended credit agreement, we have a $180 million revolving credit facility that permits us to borrow amounts from time to time based on the available borrowing base as determined in the credit agreement. The bank credit facility is secured by substantially all of our gas properties and the capital stock of our subsidiaries. The borrowing base under the bank credit facility is based upon the valuation of our gas properties as of June 30 and December 31 of each year and other factors deemed relevant by the lenders, including Bank of America as agent. The lenders may also request one additional borrowing base re-determination in any fiscal year.

As of September 30, 2007, we had $88.5 million of borrowings outstanding under our credit facility, resulting in a borrowing availability of $61.5 million under our $150 million borrowing base. For the nine months ended September 30, 2007 we borrowed $66.5 million and made payments of $38 million under the credit facility. As of September 30, 2007 the outstanding balances on the revolving credit facility bear interest at either the bank s adjusted base rate, which is the bank s base rate of at least the Federal Funds Rate plus 0.5%, or the adjusted LIBOR rate, plus a margin of 1.00% to 2.00%, based on borrowing base usage.

We are subject to certain restrictive financial and non-financial covenants under the credit agreement, including a minimum current ratio of 1.0 to 1.0, and a maximum rate of EBITDA to interest expense of 2.75 to 1.0, both as defined in the credit agreement. As of September 30, 2007, we were in compliance with all of the covenants in the credit agreement.

On October 26, 2007, the lenders, including Bank of America as agent, completed our mid-year borrowing base determination and established a borrowing base of $180 million representing an increase of 20% over the previous base of $150 million.

Note 8 Common Stock

Effective January 24, 2006, our board of directors approved a four-for-one common stock split and increased our authorized capital stock from 40,000,000 shares of common stock to 135,000,000 shares of capital stock, consisting of 125,000,000 shares of common stock and 10,000,000 shares of preferred stock. Prior periods have been adjusted for the stock split.

On January 30, 2006 and February 7, 2006, we completed private equity offerings of an aggregate 10,250,000 shares of our common stock, consisting of 2,317,023 shares issued by us and 7,932,977 shares sold by certain of our existing stockholders, to qualified institutional buyers exempt from registration under the Securities Act. We received aggregate consideration of approximately $28.0 million, or $12.09 per share. We did not receive any proceeds from the shares sold by certain of our existing stockholders. In addition, we received approximately $17.5 million from certain of the selling stockholders for repayment of loans from us, including accrued and unpaid interest thereon. We used the net proceeds from this private equity offering, together with the proceeds from the repayment of certain of the selling stockholders loans, to repay a portion of the borrowings under our bank credit facility and for general corporate purposes.

On July 27, 2006, we registered for re-sale with the SEC the 10,250,000 shares of common stock issued in the private equity offering discussed above. Also on July 27, 2006, we sold 5,750,000 shares of our common stock under an underwritten initial public offering. Our initial public offering closed on August 2, 2006, and the price per share was $10.00. We received net proceeds of approximately $52.6 million from our initial public offering, after deducting estimated offering expenses and underwriting discounts and commissions. We used the net proceeds from the initial public offering to reduce outstanding borrowings under our bank credit facility.

For the nine months ended September 30, 2007, we issued a total of 91,365 shares of common stock upon the exercise of stock options and 183,081 shares of restricted stock, net of 6,500 shares of restricted stock which were forfeited.

Note 9 Share-Based Awards

Prior to January 1, 2006, stock-based employee compensation was accounted for under the intrinsic value method of Accounting Principles Bulletin No. 25, *Accounting for Stock Issued to Employees* (APB 25). The exercise price of the options granted was equal to the estimated market value of our common stock at grant date, and therefore, no compensation costs have been recognized. We used the income method on a semi-annual basis to estimate the market value of our common stock at grant date.

Effective January 1, 2006, we adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123R, *Share-Based Payment*, using the prospective transition method. For share-based awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. Therefore, we will not recognize any equity compensation cost on these prior awards in the future unless such awards are modified, repurchased or cancelled.

As of September 30, 2007, we have two stock-based award plans authorized, our 2005 Stock Option Plan and our 2006 Long-Term Incentive Plan. However, we will not grant any additional awards under our 2005 Stock Option Plan now that we have adopted the 2006 Long-Term Incentive Plan, but we will continue to issue shares of our common stock upon exercise of awards that were previously granted under the 2005 Stock Option Plan.

Our 2006 Long-Term Incentive Plan authorized the granting of incentive stock options, non-qualified stock options, stock appreciation rights, stock awards, restricted stock, restricted stock units and performance awards. A maximum of 2,000,000 shares is available for grant under this plan. The 2006 Long-Term Incentive Plan is available to our employees and independent directors and is designed to attract and retain employees and independent directors, to further align the interest of our employees and directors interests with the interests of our stockholders, and to closely link compensation with our performance. Generally, the exercise price of a stock option granted under this plan may not be less than the fair market value of the common stock on the date of grant. The options generally have a term of seven years, vest evenly over three years, except for awards that are performance based and options issued to directors. Performance based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criterion has been met. Options issued to our directors vest immediately.

In March 2007, we granted 168,975 share-based stock option awards and in June 2007 we granted 138,000 restricted stock awards to certain of our non-executive employees with time vesting criteria and will vest as a result of a triggering event such as a corporate change of control or merger. In September 2007 we granted 219,279 share-based stock option awards and we also granted 30,145 restricted stock awards, including 20,145 to our four named executive officers and two other officers. During the nine months ended September 30, 2007, we recorded a compensation accrual of $390,496, which was allocated among general and administrative expenses ($242,106), lease operating expenses ($15,287), and gas properties ($133,103). The future compensation cost of all the outstanding awards is $2,170,448 which will be amortized over the vesting period of such stock options and restricted stock. In April and May 2006, we granted 224,810 share-based stock option awards to certain of our employees, our executive officers and our independent directors. Also in April 2006, we granted 12,249 performance based restricted stock awards to our four named executive officers and two other officers.

During the nine months ended September 30, 2006, we recorded a compensation expense accrual of $462,620 which was allocated among lease operating expenses ($109,633), general and administrative expenses ($177,743), and capitalized to unevaluated gas properties ($175,244).

Significant assumptions used in determining the compensation costs included a dividend yield of 0%, expected volatility of 40.20%, risk-free interest rate of 4.02%, an expected term of 4.5 years, and a forfeiture rate of 10%. The forfeiture rate was changed to 10% for the second quarter.

Incentive Stock Options

The table below summarizes incentive stock option activity for the nine months ended September 30, 2007:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2006	572,838	$ 6.32	4.26	
Granted	273,447	$ 8.30	6.66	
Forfeited	28,202	$ 10.04		
Exercised	91,365	$ 2.18		
Outstanding at September 30, 2007	726,718	$ 7.44	4.84	$ 631,286
Options exercisable at September 30, 2007	377,965	$ 4.63	3.01	$ 631,286

The total intrinsic value (market price less option price) of the incentive stock options exercised during the nine months ended September 30, 2007 was $411,105, and we received $198,808 in cash from the exercise of incentive stock options. The total intrinsic value (market price less option price) of incentive stock options exercised during the nine months ended September 30, 2006 was approximately $4.7 million, and we received approximately $0.6 million in cash.

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the nine months ended September 30, 2007:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2006	1,113,865	$ 3.20	6.15	
Granted	114,807	8.30	6.52	
Forfeited				
Exercised		$		
Outstanding at September 30, 2007	1,228,672	$ 3.67	5.54	$ 2,693,600
Options exercisable at September 30, 2007	1,048,000	$ 2.58	5.40	$ 2,693,600

During the nine months ended September 30, 2007, 114,807 non-qualified stock options were granted. The total intrinsic value (current market price less option strike price) of non-qualified stock options exercised during the nine months ended September 30, 2006 was approximately $1.7 million, and we received approximately $0.4 million in cash.

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the nine months ended September 30, 2007:

Non-Vested

	Restricted Stock Awards
Non-vested restricted stock at December 31, 2006	21,436
Granted	168,145
Forfeited	6,500
Vested	
Non-vested restricted stock at September 30, 2007	183,081

In September 2007 we granted 30,145 restricted stock awards, including 20,145 to our four named executive officers and two other officers. In June 2007, we granted 138,000 restricted stock awards to non-executive employees. The restricted stock awards are subject to performance-based vesting for our four named executive officers and two other officers and time-based vesting for all other employees. The restricted stock awards will vest as a result of a triggering event such as a corporate change of control or merger. The fair value of the restricted stock awards at September 30, 2007 is approximately $931,882. In April 2006, we granted 12,249 performance based restricted stock awards to our four named executive officers and two other officers.

Note 10 Commitments and Contingencies

Litigation From time to time, we are a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against us cannot be predicted with certainty, management does not believe that the adverse effect on our financial condition, our results of operations or cash flows, if any, will be material except for the litigation discussed below. As of September 30, 2007, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability.

CNX Surface Use Dispute

We have completed the construction of the 12-mile Pond Creek gathering line, a portion of which traverses a right-of-way granted by Pocahontas Mining Limited Liability Company (PMC). The Pond Creek gathering line connects with and transports our gas production from the Pond Creek field to the Jewell Ridge Pipeline. CNX Gas Company LLC (CNX), the lessee of certain minerals underlying the PMC property, has claimed that it has the exclusive right to transport gas across the PMC property and that our right-of-way is invalid. We, along with PMC, filed a complaint in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX seeking a temporary and permanent injunction, as well as a declaration of our rights under the right-of-way agreement that we entered into with PMC, the surface owner. On June 30, 2006, CNX filed a counterclaim against PMC and us seeking a declaratory judgment from the court that CNX has superior rights to our rights to the surface of the PMC property and that CNX has the exclusive right to construct pipelines, transport gas, and use roads on the PMC property. On May 23, 2007, the Circuit Court of Buchanan County, Virginia issued an interlocutory order declaring that the lease between CNX and PMC also included the exclusive right of CNX to transport gas across the PMC property and enjoined us from transporting gas through the Pond Creek gathering line over the PMC property.

On June 20, 2007, the Virginia Supreme Court vacated the injunctive portion of the order, allowing us to continue to transport gas through our Pond Creek gathering line. Also vacated was the portion of the decision that obligated us to deposit into a trust account all net proceeds from any sales of gas transported over the PMC property. On November 5, 2007, the Virginia Supreme Court accepted our petition for appeal of the remaining portion of the May 23rd order, which held that CNX has the exclusive right to build a pipeline and transport gas across the PMC property. We believe that our right-of-way agreement across the PMC property is valid and enforceable and that we will ultimately prevail in this case.

On January 19, 2007 CNX obtained a temporary injunction against our construction of the same 12-mile pipeline across 1,450 feet of a 32-acre tract in Tazewell County, Virginia. The tract of land in dispute has been owned by a large number of extended family members, from whom we have obtained approximately 81% control of the tract, either through purchases of undivided surface interests in the tract or by entering into surface use and right-of-way easement agreements. During our pipeline construction process, CNX purchased a minority undivided surface interest in the property and filed a lawsuit seeking to enjoin the construction of our Pond Creek gathering line across the tract. On February 16, 2007, the Virginia supreme court vacated the temporary injunction, which allowed us to complete construction of our Pond Creek gathering line across the 32-acre tract. Both we and CNX have filed complaints to partition the 32-acre tract, and we believe that we will obtain full ownership of the portion of the tract that our Pond Creek gathering line traverses.

Our Pond Creek gathering line is connected to the Jewell Ridge Pipeline and is fully operational. In the event we are unsuccessful in obtaining favorable judgments in the CNX surface disputes, we may be required to seek an alternative way to transport our gas to market. Assuming such an alternative is available, we may be unable to deliver our gas from the Pond Creek field to market for an extended period of time.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company, an affiliate of CNX (Island Creek), in the Circuit Court of Tazewell County, Virginia on February 14, 2007, seeking damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties and statutory and common law conspiracy. The suit seeks $561 million for compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX s alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleges CNX s intentional interference with our existing and prospective third-party business relationships in efforts to harm us and improve CNX s position and corporate and financial

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interests. We seek to have any damages awarded for alleged violations of the Virginia Antitrust Act tripled under Virginia statutes permitting a court to award treble damages, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

Note 11 Discontinued Operations

As of September 30, 2007, we discontinued the third-party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46 (R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income. As a result of exiting the third-party marketing business, we are treating these activities as a discontinued operation for all the periods presented. Results for activities reported as discontinued operations were as follows:

Statement of Operations Data:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Gas marketing revenues	$ 4,404,137	$ 5,028,774	$ 21,847,934	$ 5,028,774
Purchased gas	4,346,395	4,975,840	21,574,450	4,975,840
General and administrative		84,352		84,352
Intercompany profit		(51,727)		(51,727)
Income before tax	57,742	20,309	273,484	20,309
Income tax expense	13,124	8,145	107,972	8,145
Discontinued operations	$ 44,618	$ 12,164	$ 165,512	$ 12,164

Balance Sheet Data:

	September 30, 2007	December 31, 2006
Current Assets:		
Cash and cash equivalents	$ 186,372	$ 190,765
Accounts receivable	73,539	9,060,488
Other	14,197	15,172
Total assets	274,108	9,266,425
Current Liabilities:		
Accounts payable	129,408	9,266,425
Stockholder s equity	144,700	
Total liabilities and stockholder s equity	$ 274,108	$ 9,266,425

Note 12 Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of the FASB Statement No. 109, *Accounting for Income Taxes*. This results in the recognition of deferred tax assets and liabilities using estimated effective tax rates for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities using enacted tax rates at the end of the period. Under FASB No. 109, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change.

Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Estimating the amount of valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income, and changes in stockholder ownership that could trigger limits on use of net operating losses under Section 382 of the Internal Revenue Code. We have a significant deferred tax asset associated with net operating loss carryforwards (NOL s). It is more likely than not that we will use the NOL s in the United States to offset current tax liabilities in future years.

Our effective tax rate differs from the federal statutory rate primarily due to losses in Canada that we are unable to benefit from and state income taxes. The Canadian losses are fully reserved because it is more likely than not that we will not use those NOL s to offset current tax liabilities in future years.

Uncertain Tax Positions

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we identified $269,900 of unrecognized tax benefits, largely related to depletion methods used in years prior to 2006 from net deferred tax assets. There was no cumulative effect adjustment to retained earnings, our financial condition or results of operations as a result of implementing FIN 48 principally due to the size of our NOL s. The amount of unrecognized tax benefits did not materially change as of September 30, 2007.

As of January 1, 2007, we had $269,900 of unrecognized tax benefits. If recognized, the amount that would impact income tax expense is immaterial to the financial statements. There have been no significant changes to these amounts during the three and nine months ended September 30, 2007.

It is expected that the amount of unrecognized tax benefits may change in the next twelve months; however we do not expect the change to have a significant impact on our results of operations or the financial position.

We file a consolidated federal income tax return in the United States and various combined and separate filings in Canada and several state and local jurisdictions. With limited exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 2002.

Our continuing practice is to recognize estimated interest related to potential underpayment on any unrecognized tax benefits as a component of interest expense in the consolidated statement of operations. Penalties, if incurred, would be recognized as a component of penalty expense. As of the date of adoption of FIN 48, we did not have any accrued interest or penalties associated with any unrecognized tax benefits, nor was any interest expense recognized during the three and nine months ended September 30, 2007.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to September 30, 2008.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations
Statement Regarding Forward-Looking Information

Management s Discussion and Analysis of Financial Condition and Results of Operations and other items in this Quarterly Report on Form 10-Q contain forward-looking statements and information that are based on management s beliefs, as well as assumptions made by, and information currently available to, management. When used in this document, the words believe , anticipate , estimate , expect , intend , and similar expressions are intended to identify forward-looking statements. Although management believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that these expectations will prove to have been correct. These statements are subject to certain risks, uncertainties and assumptions. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those anticipated. We undertake no obligation to release publicly any revisions to these forward-looking statements that may be made to reflect events or circumstances after the date hereof or to reflect the occurrence of unanticipated events.

You should read Management s Discussion and Analysis of Financial Condition and Results of Operations in conjunction with the corresponding sections and our audited consolidated financial statements for the fiscal year ended December 31, 2006, which are included in our Annual Report on Form 10-K that we filed with the Securities Exchange Commission on March 20, 2007.

Overview

We are an independent natural gas producer primarily involved in the exploration, development, and production of natural gas from coal seams (coalbed methane). Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. As of September 30, 2007, we control a total of approximately 303,456 net acres of coalbed methane and oil and gas development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia.

Our business strategy is centered on investing capital to increase our reserves, production, cash flow and earnings while at the same time optimizing our unused borrowing capacity. Our current focus is to exploit our existing inventory of projects and expand into adjacent areas to leverage on our knowledge of the area and our existing infrastructure and operating base. In addition, we focus on exploring for large-scale CBM development opportunities both in existing core areas and in other areas that we enter, where we intend to have operating control and the ability to reduce costs through economies of scale. More specifically, we are currently concentrating on improving production and continued development at the Gurnee field located in the Cahaba Basin and the Pond Creek field located in the central Appalachian Basin. Other projects in progress consist of the Peace River Project in British Columbia and the Lasher Project in Wyoming and McDowell counties, West Virginia which are two CBM projects in the pre-developmental phase, and the Garden City Prospect in Blount and Cullman counties in north central Alabama, our new Chattanooga Shale exploration prospect.

Our financial results are impacted by many factors such as the price of natural gas, our levels of production, and our ability to market our production. Commodity prices and production volumes are affected by changes in market demand, which is impacted by overall economic activity, weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas prices and levels of production, and, therefore, we cannot determine what effect increases or decreases will have on our capital program, future revenues and reserves. In addition to production volumes and commodity prices, finding and developing sufficient amounts of natural gas reserves at economical costs are critical to our long-term success.

For the three and nine months ended September 30, 2007, gas sales quantities increased by 149 MMcf and 770 MMcf from the comparable prior period to 1.8 Bcf and 5.3 Bcf, respectively. The increase in sales was related to the continued development of our Gurnee and Pond Creek fields. Average gas sales prices for the three and nine months ended September 30, 2007 decreased by $0.37 and $0.47 per Mcf from the comparable prior period to $6.26 per Mcf and $6.94 per Mcf, respectively.

To reduce our exposure to fluctuations in natural gas prices, which have exhibited a high degree of volatility over the past several years, we periodically enter into derivative commodity instruments. Currently, we use three-way collars, collars and swaps as our mechanism for hedging commodity prices. We account for our derivative instruments on a mark-to-market basis, and changes in the fair value of derivative instruments are recognized as gains and losses which are included in operating expense in the period of change. While we believe that the stabilization of prices and protection afforded us by providing a revenue floor for our sales is beneficial, this strategy may result in lower revenues than we would have recognized if we were not a party to derivative instruments in times of rising natural gas prices. Our policy is to enter into hedging transactions that increase our probability of achieving our targeted level of cash flows. As a result of these hedging positions, during the three and nine months ended September 30, 2007, we recognized gains of $1.7 million and $0.3 million including realized gains of $1.2 million and $2.5 million, respectively. During the three and nine months ended September 30, 2006, we recognized gains on derivative contracts of $4.7 million and $15.0 million including realized gains of $551,475 and losses of $395,271, respectively.

We believe that our cash flow from operations and other financial resources such as borrowings under our credit facility and proceeds from future equity offerings will provide us with the ability to develop our existing properties and finance our current exploration on unevaluated properties.

Recent Developments

Garden City Project

Garden City is our new Chattanooga Shale exploration prospect that was announced in August, 2007. We have acquired more than 61,000 gross acres of leasehold in Blount and Cullman counties in north central Alabama. We own 100% working interest and operate. The Chattanooga Shale is expected to be encountered at an average depth of 1,700 to 2,000 feet across the prospect area. We have drilled 5 core holes to determine the gas in place and the reservoir properties of the shale. We have also drilled our first of 3 production test wells for this year.

Critical Accounting Policies

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires us to use our judgment to make estimates and assumptions that affect certain amounts reported in our financial statements. As additional information becomes available, these estimates and assumptions are subject to change and thus impact amounts reported in the future. Critical accounting polices are those accounting policies that involve judgment and uncertainties affecting the application of those policies and the likelihood that materially different amounts would be reported under different conditions or using differing assumptions. We periodically update our estimates used in the preparation of the financial statements based on our latest assessment of the current and projected business and general economic environment. There have been no significant changes to our critical accounting policies during the nine months ended September 30, 2007.

Natural Gas Production Producing Fields Operations Summary

The table below presents information on gas revenues, sales volumes, production expenses and per Mcf data for the three and nine months ended September 30, 2007 and 2006. This table should be read with the discussion of the results of operations for the periods presented below (in thousands).

	Three Months Ended		Nine Months Ended	
	September 30,			
	2007	2006	2007	2006
Gas sales	$ 11,303	$ 10,917	$ 36,590	$ 33,368
Lease operating expenses	$ 3,560	$ 2,510	$ 10,353	$ 8,184
Compression and transportation expenses	1,166	1,041	4,033	3,172
Production taxes	260	260	858	765
Total production expenses	$ 4,986	$ 3,811	$ 15,244	$ 12,121
Net sales volumes (MMcf)	1,804	1,655	5,271	4,501
Pond Creek field	1,150	1,000	3,326	2,783
Gurnee field	560	547	1,648	1386
Per Mcf data ($/Mcf):				
Average natural gas sales price	$ 6.26	$ 6.60	$ 6.94	$ 7.41
Average natural gas sales price realized(1)	$ 6.95	$ 6.92	$ 7.42	$ 7.50
Lease operating expenses	$ 1.97	$ 1.52	$ 1.96	$ 1.82
Pond Creek field	$ 1.56	$ 1.13	$ 1.65	$ 1.37
Gurnee field	$ 3.13	$ 2.52	$ 2.95	$ 3.14
Compression and transportation expenses	$ 0.65	$ 0.63	$ 0.77	$ 0.71
Pond Creek field	$ 0.79	$ 0.84	$ 1.00	$ 0.94

Gurnee field	$	0.47	$	0.36	$	0.45	$	0.39
Production taxes	$	0.14	$	0.16	$	0.16	$	0.17
Pond Creek field	$	0.01	$	0.01	$	0.01	$	0.02
Gurnee field	$	0.37	$	0.37	$	0.42	$	0.42
Total production expenses	$	2.76	$	2.31	$	2.89	$	2.70
Pond Creek field	$	2.37	$	1.98	$	2.66	$	2.33
Gurnee field	$	3.97	$	3.25	$	3.81	$	3.95
Depreciation, depletion and amortization	$	1.30	$	1.31	$	1.27	$	1.28

(1) Average realized price includes the effects of realized (gains) losses on derivative contracts.

Results of Operations

Three Months Ended September 30, 2007 compared with Three Months Ended September 30, 2006

The following are selected items derived from our Consolidating Statement of Operations and their percentage changes from the comparable period are presented below.

	Three Months Ended September 30,		
	2007	2006	Change
	(In thousands)		
Gas sales	$ 11,303	$ 10,918	3%
Operating fees and other	341		100%
Total revenues	$ 11,644	$ 10,918	7%
Lease operating expenses	$ 3,560	$ 2,510	(42)%
Compression and transportation expenses	1,166	1,041	(12)%
Production taxes	260	260	(0)%
Depreciation, depletion and amortization	2,347	2,168	(8)%
Research and development	12	16	NM
General and administrative	2,526	1,869	(35)%
Realized losses (gains) on derivative contracts	(1,228)	(551)	NM
Unrealized (gains) from the change in market value of open derivative contracts	(464)	(4,134)	NM
Total operating expenses	$ 8,179	$ 3,179	NM
Income (loss) from operations	$ 3,465	$ 7,739	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $0.385 million, or 3%, to $11.3 million compared to the prior year quarter. The increase in gas sales was primarily a result of increased production. Production increased 9% while average gas prices decreased 6%, excluding hedging transactions. The $0.385 million increase in gas sales consisted of a $0.602 million decrease in prices and a $0.987 million increase in production. The increase in production was principally attributable to the continued development activities at our Gurnee and Pond Creek fields.

Lease operating expenses. Lease operating expenses increased by $1.1 million, or 42%, to $3.6 million. The increase in lease operating expenses consisted of $0.226 million increase in production and $0.824 million increase in costs. The increase in costs is due to well treatments, well servicing and increased ad valorem taxes.

Compression and transportation expenses. Compression and transportation expenses increased by $0.125 million, or 12%, to $1.2 million. The increase in compression and transportation expenses consisted of a $0.094 million increase in production and a $0.031 million increase in costs. The primary driver in the increased compression and transportation costs is due to increased compressors and related costs compared to the prior period, partially offset by decreased interruptible transportation costs.

Production taxes. Production taxes remained the same at $0.260 million. Production taxes were flat and consisted of a $0.023 million increase in production and $0.023 million decrease in average gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $0.179 million, or 8%, to $2.3 million. The depreciation, depletion and amortization increase consisted of a $0.195 million increase in production and $0.016 million decrease in the depletion rate.

General and administrative. General and administrative expenses increased by $0.657 million or, 35%, to $2.5 million. The primary drivers for the increased general and administrative expenses were professional services and employee expenses. Professional services consisted of increased audit fees, Sarbanes-Oxley compliance costs, tax services and legal services. Employee expenses increased as a result of increased personnel and higher costs of salary and wages partially offset by increased overhead recoveries.

Realized losses (gains) on derivative contracts. Realized gains on derivative contracts increased by $0.677 million to $1.228 compared to a $0.551 million in the prior year quarter. Realized losses represent net cash flow settlements paid to the counterparty, while realized gains represent net cash flow settlement paid to us from the counterparty. Realized losses occur when commodity gas prices or the derivative index price exceeds the derivative ceiling price. Conversely, realized gains occur when commodity gas prices go below the derivative floor price.

Unrealized losses (gains) from the change in market value of open derivative contracts. Unrealized gains from the change in market value of open derivative contracts resulted in a $0.464 million gain as compared to a $4.134 million gain in the prior year quarter. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period. Unrealized gains are recognized when the fair values of derivative assets increase or the fair value of derivative liabilities decrease. Unrealized losses are recognized when the fair values of derivative assets decrease or the fair values of derivative liabilities increase. The $0.464 million gain was a result of decreased future commodity gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $0.710 million, or 96%, to $1.4 million. The increase was primarily due to higher outstanding debt and slightly higher interest rates. Capitalized interest totaled $0.080 million and $0.202 for the three months ended September 30, 2007 and 2006, respectively.

Income tax expense (benefit). Income tax expense decreased by $2.3 million to $0.454 million. The income tax expense decrease in the current quarter was due to decreased pretax income versus the comparable prior period. In addition, the effective tax rate decreased for the current quarter to 23% from 39% in the comparable prior period. The principal driver for the difference in the effective tax rate was due to lower state income taxes resulting from state apportionment factor shifting.

Discontinued Operations. As of September 30, 2007, we discontinued the third party marketing business and second reportable segment that had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46 (R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income. As a result of exiting our third party marketing business, we are treating these activities as a discontinued operation for all the periods presented.

Results of Operations

Nine Months Ended September 30, 2007 compared with Nine Months Ended September 30, 2006

The following are selected items derived from our Consolidating Statement of Operations and their percentage changes from the comparable period are presented below.

	Nine Months Ended September 30,		
	2007	2006	Change
	(In thousands)		
Gas sales	$ 36,590	$ 33,368	10%
Operating fees and other	957		NM
Total revenues	$ 37,547	$ 33,368	NM
Lease operating expenses	$ 10,353	$ 8,184	(27)%
Compression and transportation expenses	4,033	3,172	(27)%
Production taxes	858	765	(12)%
Depreciation, depletion and amortization	6,688	5,749	(16)%

Research and development	12	114	NM
General and administrative	7,029	4,326	(62)%
Realized losses (gains) on derivative contracts	(2,524)	(395)	NM
Unrealized losses (gains) from the change in market value of open derivative contracts	2,249	(14,579)	NM
Total operating expenses	$ 28,698	$ 7,336	NM
Income (loss) from natural gas production	$ 8,849	$ 26,032	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $3.2 million, or 10%, to $36.6 million compared to the prior nine-month period. The increase in gas sales was primarily a result of increased production, which was partially offset by decreased average sales prices. Production increased 17% while average gas prices decreased 6%, excluding hedging transactions. The $3.2 million increase in gas sales consisted of a $5.7 million increase in production, partially offset by a $2.5 million decrease in average prices. The increase in production was principally attributable to the continued development activities at our Gurnee and Pond Creek fields.

Lease operating expenses. Lease operating expenses increased by $2.2 million, or 27%, to $10.4 million. The increase in lease operating expenses consisted of $1.4 million increase in production and a $0.769 million increase in costs. The increase in costs is due to well treatments, well servicing and increased ad valorem taxes.

Compression and transportation expenses. Compression and transportation expenses increased by $0.861 million, or 27%, to $4.0 million. The increase in compression and transportation expenses consisted of a $0.543 million increase in production and a $0.318 million increase in costs. The increase in compression costs is due to increased compressors and related costs compared to the prior period. The increase in transportation costs is due to two firm transportation agreements compared to one in the prior period and increased interruptible transportation costs for a portion of the period.

Production taxes. Production taxes increased by $0.093 million, or 12%, to $0.858 million. The production taxes increase was primarily due to increased production, partially offset by decreasing average gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $0.939 million, or 16%, to $6.7 million. The depreciation, depletion and amortization increase consisted of a $0.983 million increase in production and $0.044 million decrease in the depletion rate**.** However, the prior year period includes a $300,000 adjustment to depreciation, depletion and amortization related to the adjustment of certain state taxes not recorded in prior periods. Excluding the $300,000 adjustment, the depletion rate per Mcf increased from $1.21 to $1.27. The increase in the rate is due to increased future development costs and higher cost of drilling.

General and administrative. General and administrative expenses increased by $2.7 million or, 62%, to $7.0 million. The primary drivers for the increased general and administrative expenses were professional services and employee expenses. Professional services consisted of increased audit fees, Sarbanes-Oxley compliance costs, tax services and legal services. Employee expenses increased as a result of increased personnel and higher costs of salary and wages partially offset by overhead recoveries.

Realized losses (gains) on derivative contracts. Realized gains on derivative contracts increased by $2.1 million to $2.5 million. Realized losses represent net cash flow settlements paid to the counterparty, while realized gains represent net cash flow settlement paid to us from the counterparty. Realized losses occur when commodity gas prices or the derivative index price exceeds the derivative ceiling price. Conversely, realized gains occur when commodity gas prices go below the derivative floor price.

Unrealized losses (gains) from the change in market value of open derivative contracts. Unrealized losses (gains) from the change in market value of open derivative contracts resulted in a $2.2 million loss as compared to a $14.6 million gain in the prior period. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period. Unrealized gains are recognized when the fair values of derivative assets increase or the fair value of derivative liabilities decrease. Unrealized losses are recognized when the fair values of derivative assets decrease or the fair values of derivative liabilities increase. The $2.2 million loss was a result of increased future commodity gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $1.216 million, or 51%, to $3.6 million. The increase was primarily due to higher outstanding debt and slightly higher interest rates. Capitalized interest totaled $0.446 million and $0.644 for the nine months ended September 30, 2007 and 2006, respectively.

Income tax expense (benefit). Income tax expense decreased by $8.1 million to $1.9 million. The decrease in income tax expense for the current period was due to decreased pretax income compared to the prior period. In addition, the effective tax rate decreased for the current quarter to 35% from 42% in the comparable prior period. The principal driver for the difference in the effective tax rate was due to lower state income taxes resulting from state apportionment factor shifting.

Discontinued operations. As of September 30, 2007, we discontinued the third party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46 (R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income. As a result of exiting our third party marketing business, we are treating these activities as a discontinued operation for all the periods presented.

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flow from operations for the nine months ended September 30, 2007 and 2006 were $16.2 million and $21.3 million, respectively. Cash flow from operations of $16.2 million for the nine months ended September 30, 2007, combined together with net cash provided by financing activities of $28.8 million, were sufficient to fund net cash used in investing activities of $44.8 million, which primarily includes capital expenditures for the exploration and development of our gas properties. Net cash provided by financing activities includes $28.5 million related to the credit facility net borrowings.

As of September 30, 2007 and December 31, 2006, we had a working capital deficit of approximately $3.0 million and $1.6 million, respectively. At September 30, 2007, we had adequate cash flows from operating activities and adequate credit availability to fund our working capital deficits.

Based upon current expectations, we believe that our cash flow from operations and other financial resources such as borrowings under our credit facility and proceeds from future equity offerings will provide us with the ability to develop our existing properties and conduct exploration on our unevaluated properties.

If natural gas commodity prices decrease from their current levels for an extended period, our ability to finance our planned capital expenditures could be negatively affected. Furthermore, amounts available for borrowing under our revolving credit facility are largely dependent on our level of estimated proved reserves and current natural gas prices. If either our estimated proved reserves or natural gas prices decrease, the amount available for us to borrow under our revolving credit facility could be negatively affected. If our cash flows are less than anticipated, if the amounts available for borrowing under our revolving credit facility are reduced, or if we are unable to sell equity at acceptable prices, we may be forced to defer planned capital expenditures.

Price Risk Management Activities

The energy markets have historically been very volatile, and there can be no assurance that natural gas prices will not be subject to wide fluctuations in the future. In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has adopted a policy of hedging natural gas prices from time to time primarily three-way collars, traditional collars and swaps. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

We enter into hedging transactions that increase our statistical probability of achieving our targeted level of cash flows and at times hedged forward for periods of more than two years. We generally limit the amount of these hedges during any period to no more than 50% to 60% of the then expected gas production for such future periods. We have historically used swaps, costless collars and three-way costless collars in our hedging activities. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling and a minimum floor future price. Three-way costless collars are similar to regular costless collars except that, in order to increase the ceiling price, we agree to limit the amount of the floor price protection to a predetermined amount, generally between $1.00 and $3.00 per MMBtu. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses during periods where prices rise above the level of our hedges and gains during periods where prices drop below the level of our hedges causing significant fluctuations in our statement of operations.

We believe that the use of derivative instruments does not expose us to material risk. However, the use of derivative instruments could materially affect our results of operations depending on the future prices of natural gas. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our financial position or liquidity.

We account for our derivative contracts as accounting hedges using mark-to-market accounting under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* As of September 30, 2007, the following natural gas derivative contracts were outstanding with prices expressed in dollars per million British thermal units ($/MMBtu) and notional volumes in million British thermal units. The daily volumes that we hedge are equal during each production period. For our natural gas derivative contracts, summer months apply to April through October and winter months apply to November through March.

			Collars	
Instrument Type	**Production Period**	**Volumes (MMBtu)**	**Weighted Average Floor Prices ($/MMBtu)**	**Weighted Average Cap Prices ($/MMBtu)**
Collars (3 way)	October 2007	248,000	$ 5.75-$7.38	$ 10.50
Traditional Collars	October 2007	124,000	$ 7.50	$ 9.75
Collars (3 way)	Winter 2007/2008	1,216,000	$ 6.00-$9.00	$ 14.80
Traditional Collars	Winter 2007/2008	608,000	$ 8.25	$ 11.25
Collars (3 way)	Summer 2008	1,712,000	$ 5.00-$7.00	$ 10.50

At September 30, 2007 and at December 31, 2006, the fair values of net open derivative contract assets were approximately $3.1 and $5.3 million, respectively. On October 15, 2007 we entered into a swap for 856,000 MMBtu s with a fixed price of $8.00 for the period April 2008 through October 2008. On October 29, 2007 we entered into a three way collar for 906,000 MMBtu s with a cap price of $11.00 per MMBtu and floor prices of $8.50 per MMBtu and $6.25 per MMBtu for the period November 2008 through March 2009. On November 1, 2007 we entered into a three way collar for 1,284,000 MMBtu s with a cap price of $10.00 per MMBtu and floor prices of $7.50 Per MMBtu and $5.25 per MMBtu for the period April through October 2009.

We use a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market of natural gas may have on the fair value of our derivative instruments. At September 30, 2007, the potential change in the fair value of our derivative contracts assuming a 10% increase in the underlying commodity price was a $1.5 million decrease in the unrealized gain on derivative contracts reported on our unaudited consolidated statements of operations and comprehensive income for the three months ended September 30, 2007.

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants in our credit agreement and the collateral for the outstanding borrowings under our credit agreement is used as collateral for our hedges.

Capital Expenditures and Capital Resources

The development of coalbed methane fields requires substantial initial investment before meaningful production and resulting cash flows are realized. Among the factors that can be expected to affect our cash flows and liquidity are the characteristics of the field, the amount of water produced, the methods utilized to dispose of produced water, the transportation alternatives, and the timing and volume of initial and subsequent natural gas production volumes. We estimate total capital expenditures in 2007 will be approximately $59 million, with $48 million going toward the development of the Gurnee field and Pond Creek field. The amount represents an approximate 24% decrease in capital expenditures from 2006 and is primarily attributable to decreased development expenditures at our Gurnee field and Pond Creek field partially offset by increased expenditures in our other projects. We have decided to reallocate capital to fund well treatments in the Gurnee field and to provide additional capital for the other projects discussed above in Overview. Capital expenditures for the nine months ended September 30, 2007 and 2006 were $45 million and $62 million, respectively, and have been primarily concentrated in the Pond Creek field, the Gurnee field and in the Peace River Project.

Credit Facility

In June 2006, we entered into a $180 million amended and restated credit agreement with Bank of America, N.A., as agent, and other lenders. Availability under our credit agreement is subject to a borrowing base, which is currently set at $180 million. The borrowing base is subject to semi-annual re-determinations. The lenders also have the right to require one additional re-determination in any fiscal year. Our credit agreement provides for interest to accrue at a rate calculated, at our option, at either the adjusted base rate (which is the greater of the agent s base rate or the federal funds rate plus one half of one percent) or the London Inter-bank Offered Rate (LIBOR) plus a margin of 1.00% to 2.00%, based on borrowing base usage. Borrowings under our credit agreement are secured by first priority liens on substantially all of our assets including equity interests in our subsidiaries. All outstanding borrowings under our credit agreement become due and payable on January 6, 2011.

We are subject to financial covenants requiring maintenance of a minimum current ratio and a minimum interest coverage ratio. Our ratio of consolidated current assets (defined to include amounts available under our borrowing base) to our consolidated current liabilities is not permitted to be less than 1 to 1 as of the end of any fiscal quarter, and our ratio of consolidated EBITDA for the four preceding quarters at the end of each fiscal quarter to the sum of our consolidated net interest expense for the same period plus letter of credit fees accruing during such quarter is not permitted to be less than 2.75 to 1. Consolidated EBITDA as defined in the amended credit agreement excludes other non-cash charges deducted in determining net income (loss), which would include unrealized gains and losses from the change in the market value of open derivative contracts. In addition, we are subject to covenants restricting or prohibiting cash dividends and other restricted payments, transactions with affiliates, incurrence of debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities, and liens on properties. A breach of any of the covenants imposed on us by the terms of our credit facility, including the financial covenants, could result in a default under such indebtedness. In the event of a default, the lenders could terminate their commitments to us, and they could accelerate the repayment of all of our indebtedness. In such case, we may not have sufficient funds to pay the total amount of accelerated obligations, and our lenders could proceed against the collateral securing the facility. Any acceleration in the repayment of our indebtedness or related foreclosure could adversely affect our business.

In addition, the borrowing base under our credit facility is re-determined semi-annually and may also be re-determined once each fiscal year for any reason upon request by lenders representing 66.66% of the total commitment under our credit facility. Re-determinations are based upon a number of factors, including commodity prices and reserve levels. On October 26, 2007, the lenders, including Bank of America as agent completed our mid-year borrowing base determination and established a borrowing base of $180 million representing an increase of 20% over the previous base of $150 million.

The next scheduled re-determination is expected to be completed on or before June 30, 2008 based upon the year end 2007 reserve report and other factors. Upon a re-determination, we could be required to repay a portion of our bank debt. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the credit facility and an acceleration of our indebtedness.

At September 30, 2007, $88.5 million was outstanding under our credit facility. Interest on the borrowings averaged 6.61% per annum. Borrowing availability at September 30, 2007 was $61.5 million based on the $150 million borrowing base prior to the most recent re-determination. All of the debt outstanding under our credit facility accrues interest at floating or market rates. Fluctuations in market interest rates will cause our interest costs to fluctuate. Based upon the balance outstanding under our credit facility at September 30, 2007, a 1% change in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $805,000.

At September 30, 2007, we did not have any hedges in place to reduce our risk to increases in interest rates.

Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments.

Discontinued Operations

As of September 30, 2007, we discontinued the third party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46 (R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income. As a result, we are treating our third party marketing activities as a discontinued operation for all the periods presented.

The marketing activities of Shamrock Energy LLC have been transitioned to GeoMet, Inc without disruption in the marketing of our gas and we do not expect to incur significant liabilities or sell any assets in connection with discontinuing this business. As a result, the discontinued operations have an insignificant impact on our cash flows.

Foreign Currency Exchange Rate Risk

We have exploratory operations in Canada and do not have operations in any other foreign countries. We do not hedge our foreign currency risk and are exposed to foreign currency exchange rate risk in the Canadian dollar. Because our Canadian project is exploratory, the effect of changes in the exchange rate does not impact our revenues or expenses but primarily affects the costs of unevaluated properties. We continue to monitor the foreign currency exchange rate in Canada and may implement measures to protect against the foreign currency exchange rate risk in the future.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are engaged primarily in the exploration, development, and production of coalbed methane in the U. S. and Canada. As a result, we are exposed to certain market risks that include financial instruments such as short term cash equivalents, accounts receivables, long-term debt, foreign currency and commodity risk. For a discussion of our commodity, interest rate risks and foreign currency risk, see the discussions set forth above in Item 2, Management s Discussion and Analysis of Financial Condition and Results of Operations, under the subheadings Liquidity and Capital Resources Price Risk Management Activities, Liquidity and Capital Resources Credit Facility, and Liquidity and Capital Resources Foreign Currency Exchange Rate Risk .

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our chief executive officer and chief financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2007 in ensuring that material information was accumulated and communicated to management, and made known to our chief executive officer and chief financial officer, on a timely basis to allow disclosure as required in this report.

Changes in Internal Controls Over Financial Reporting

During the period covered by this report, there were no changes that occurred that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

Litigation From time to time, we are a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against us cannot be predicted with certainty, management does not believe that the adverse effect on our financial condition, our results of operations or cash flows, if any, will be material except for the litigation discussed below. As of September 30, 2007, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability.

CNX Surface Use Dispute

We have completed the construction of the 12-mile Pond Creek gathering line, a portion of which traverses a right-of-way granted by Pocahontas Mining Limited Liability Company (PMC). The Pond Creek gathering line connects with and transports our gas production from the Pond Creek field to the Jewell Ridge Pipeline. CNX Gas Company LLC (CNX), the lessee of certain minerals underlying the PMC property, has claimed that it has the exclusive right to transport gas across the PMC property and that our right-of-way is invalid. We, along with PMC, filed a complaint in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX seeking a temporary and permanent injunction, as well as a declaration of our rights under the right-of-way agreement that we entered into with PMC, the surface owner. On June 30, 2006, CNX filed a counterclaim against PMC and us seeking a declaratory judgment from the court that CNX has superior rights to our rights to the surface of the PMC property and that CNX has the exclusive right to construct pipelines, transport gas, and use roads on the PMC property. On May 23, 2007, the Circuit Court of Buchanan County, Virginia issued an interlocutory order declaring that the lease between CNX and PMC also included the exclusive right of CNX to transport gas across the PMC property and enjoined us from transporting gas through the Pond Creek gathering line over the PMC property.

On June 20, 2007, the Virginia Supreme Court vacated the injunctive portion of the order, allowing us to continue to transport gas through our Pond Creek gathering line. Also vacated was the portion of the decision that obligated us to deposit into a trust account all net proceeds from any sales of gas transported over the PMC property. On November 5, 2007, the Virginia Supreme Court accepted our petition for appeal of the remaining portion of the May 23rd order, which held that CNX has the exclusive right to build a pipeline and transport gas across the PMC property. We believe that our right-of-way agreement across the PMC property is valid and enforceable and that we will ultimately prevail in this case.

On January 19, 2007 CNX obtained a temporary injunction against our construction of the same 12-mile pipeline across 1,450 feet of a 32-acre tract in Tazewell County, Virginia. The tract of land in dispute has been owned by a large number of extended family members, from whom we have obtained approximately 81% control of the tract, either through purchases of undivided surface interests in the tract or by entering into surface use and right-of-way easement agreements. During our pipeline construction process, CNX purchased a minority undivided surface interest in the property and filed a lawsuit seeking to enjoin the construction of our Pond Creek gathering line across the tract. On February 16, 2007, the Virginia supreme court vacated the temporary injunction, which allowed us to complete construction of our Pond Creek gathering line across the 32-acre tract. Both we and CNX have filed complaints to partition the 32-acre tract, and we believe that we will obtain full ownership of the portion of the tract that our Pond Creek gathering line traverses.

Our Pond Creek gathering line is connected to the Jewell Ridge Pipeline and is fully operational. In the event we are unsuccessful in obtaining favorable judgments in the CNX surface disputes, we may be required to seek an alternative way to transport our gas to market. Assuming such an alternative is available, we may be unable to deliver our gas from the Pond Creek field to market for an extended period of time.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company, an affiliate of CNX (Island Creek), in the Circuit Court of Tazewell County, Virginia on February 14, 2007, seeking damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties, and statutory and common law conspiracy. The suit seeks $561 million for compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX s alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleges CNX s intentional interference with our existing and prospective third-party business relationships in efforts to harm us and improve CNX s position and corporate and financial interests. We seek to have any damages awarded for alleged violations of the Virginia Antitrust Act tripled under Virginia statutes permitting a court to award treble damages, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in the Risk Factors section of our Annual Report on Form 10-K for the year ended December 31, 2006.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

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

None.

Item 5. Other Information.

None.

Item 6. Exhibits.

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report on Form 10-Q.

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.

GeoMet, Inc.

Date: November 9, 2007

By /s/ William C. Rankin
William C. Rankin, Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

INDEX TO EXHIBITS

Exhibit Number	**Exhibits**
31.1*	Certification of the Company s Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company s Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
32*	Certification of the Company s Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).

* Attached hereto