GeoMet, Inc.
Form 424B3
November 14, 2006

Filed pursuant to Rule 424(b)(3)

Registration Statement No. 333-131716

PROSPECTUS SUPPLEMENT NO. 2

to prospectus dated July 27, 2006

10,250,000 Shares

Common Stock

The following information supplements the prospectus dated July 27, 2006 relating to the offer and sale by the selling stockholders identified in the prospectus of up to 10,250,000 shares of our common stock. This prospectus supplement includes our Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, which was filed with the U.S. Securities and Exchange Commission on November 13, 2006.

The information contained in such report is dated as of the date of such report. This prospectus supplement should be read in conjunction with the prospectus dated July 27, 2006, which is to be delivered with this prospectus supplement. This prospectus supplement is qualified by reference to the prospectus except to the extent that the information in this prospectus supplement updates and supersedes the information contained in the prospectus dated July 27, 2006, including any supplements or amendments thereto.

Investing in the shares involves risks and uncertainties. See Risk Factors beginning on page 10 of the prospectus dated July 27, 2006 and the risk factors included in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus supplement is November 14, 2006.

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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, 2006

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. Yes x 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 ¨ No x

As of November 7, 2006, there were 38,626,665 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, 2006	December 31, 2005
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,924,272	$ 615,806
Accounts receivable	6,881,058	5,577,140
Current portion of notes receivable	79,701	310,210
Deferred tax asset		2,911,808
Derivative asset	1,743,220	
Other current assets	832,894	414,232
Total current assets	12,461,145	9,829,196
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	289,875,036	229,519,222
Unevaluated gas properties, not subject to amortization	27,433,229	20,680,712
Other property and equipment	2,268,083	1,841,056
Total property and equipment	319,576,348	252,040,990
Less accumulated depreciation, depletion, and amortization	(20,836,288)	(15,392,300)
Property and equipment net	298,740,060	236,648,690
Other noncurrent assets:		
Note receivable	305,376	323,879
Derivative asset	1,292,046	
Other	697,600	1,107,234
Total other noncurrent assets	2,295,022	1,431,113
TOTAL ASSETS	$ 313,496,227	$ 247,908,999
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 16,877,646	$ 6,861,075
Derivative liability		8,931,926
Deferred tax liability	699,031	
Asset retirement liability	52,726	51,510
Accrued liabilities	1,993,170	1,265,989
Current portion of long-term debt	92,887	86,472
Total current liabilities	19,715,460	17,196,972
Long-term debt	41,847,302	99,926,378
Long-term derivative liability		2,611,592

Asset retirement liability	2,230,886	1,838,663
Other long-term accrued liabilities		258,573
Deferred income taxes	42,924,305	30,654,545
TOTAL LIABILITIES	106,717,953	152,486,723
Minority interest	12,164	
Commitments and contingencies (Note 11)		
Stockholders Equity:		
Preferred stock, $0.001 par value authorized 10,000,000, none issued		
Common stock, $0.001 par value authorized 125,000,000, and 40,000,000 shares; issued and outstanding 38,626,665 and 29,974,664 at September 30, 2006 and December 31, 2005, respectively	38,627	29,975
Paid-in capital	186,684,645	106,408,915
Accumulated other comprehensive income	341,444	56,310
Retained earnings	20,125,775	6,443,928
Less notes receivable	(424,381)	(17,516,852)
TOTAL STOCKHOLDERS EQUITY	206,766,110	95,422,276
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 313,496,227	$ 247,908,999

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Income

(Unaudited)

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Revenues:				
Gas sales	$ 10,968,436	$ 10,542,159	$ 33,419,380	$ 24,240,126
Gas marketing	5,028,774		5,028,774	
Operating fees and other		3,848		375,509
Total revenues	15,997,210	10,546,007	38,448,154	24,615,635
Expenses:				
Purchased gas	4,975,840		4,975,840	
Lease operating expense	2,509,875	2,317,593	8,183,527	6,211,819
Compression and transportation expense	1,040,660	850,620	3,172,298	2,331,618
Production taxes	259,915	230,802	764,852	518,556
Depreciation, depletion and amortization	2,168,456	1,028,630	5,748,942	3,377,617
Research and development	16,162	211,056	114,554	531,314
General and administrative	1,952,510	721,535	4,408,090	2,277,153
Realized (gains) losses on derivative contracts	(551,475)	2,152,429	(395,271)	2,288,724
Unrealized (gains) losses on derivative contracts	(4,134,128)	19,163,601	(14,578,784)	21,833,559
Total operating expenses	8,237,815	26,676,266	12,394,048	39,370,360
Income (loss) from operations	7,759,395	(16,130,259)	26,054,106	(14,754,725)
Other income (expense):				
Interest income	6,938	7,487	25,151	33,317
Interest expense (net of amounts capitalized)	(738,501)	(1,053,783)	(2,367,640)	(2,533,769)
Other	(22,867)	(6,952)	(4,598)	(6,952)
Total other expense	(754,430)	(1,053,248)	(2,347,087)	(2,507,404)
Income (loss) before income taxes and minority interest, net of income tax	7,004,965	(17,183,507)	23,707,019	(17,262,129)
Income tax expense (benefit)	2,765,272	(5,840,868)	10,013,008	(5,842,601)
Net income (loss) before minority interest , net of income tax	4,239,693	(11,342,639)	13,694,011	(11,419,528)
Minority interest loss (earnings), net of income tax	12,164		12,164	(442,336)
Net income (loss)	$ 4,227,529	$ (11,342,639)	$ 13,681,847	$ (10,977,192)
Other comprehensive income, net of income taxes				
Foreign currency translation adjustment, net of income tax of $0	45,481	85,490	285,134	67,951
Comprehensive income (loss)	$ 4,273,010	$ (11,257,149)	$ 13,966,981	$ (10,909,241)
Net income (loss) per common share:				
Basic	$ 0.11	$ (0.41)	$ 0.40	$ (0.40)

Diluted	$ 0.11	$ (0.41)	$ 0.39	$ (0.40)
Weighted average number of common shares:				
Basic	36,921,141	27,664,973	33,799,293	27,555,076
Diluted	37,770,453	27,664,973	34,801,578	27,555,076

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Stockholders Equity and Accumulated Other Comprehensive Income

(Unaudited)

		September 30, 2006
Preferred stock, $0.001 par value shares outstanding, none		
Common stock, $0.001 par value shares outstanding:		
Balance at beginning of year		29,974,664
144A offering, sale of common stock		2,317,023
Initial public offering		5,750,000
Exercise of stock options		584,978
Balance at end of period		38,626,665
Common stock, $0.001 par value:		
Balance at beginning of year	$	29,975
144A offering, sale of common stock		2,317
Initial public offering		5,750
Exercise of stock options		585
Balance at end of period	$	38,627
Paid-in capital:		
Balance at beginning of year	$	106,408,915
144A offering, sale of common stock		28,010,491
Initial public offering		53,469,250
Exercise of stock options		1,010,377
Offering costs		(2,996,890)
Stock-base compensation, including $815,735 of income tax benefit		1,278,355
Accrued interest on all notes receivable issued to purchase common stock, net of income tax		(495,853)
Balance at end of period	$	186,684,645
Accumulated other comprehensive income:		
Balance at beginning of year	$	56,310
Foreign currency translation adjustment, net of income tax of $0		285,134
Balance at end of period	$	341,444
Retained earnings:		
Balance at beginning of year	$	6,443,928
Net income		13,681,847
Balance at end of period	$	20,125,775
Notes receivable:		
Balance at beginning of year	$	(17,516,852)
Payments		17,184,357
Accrued interest on notes receivable issued to purchase common stock		(91,886)

Balance at end of period	$	(424,381)
Total Stockholders Equity	$	206,766,110

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Nine Months Ended September 30, 2006	2005
Cash flows provided by operating activities:		
Net income (loss)	$ 13,681,847	$ (10,977,192)
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	5,863,879	3,513,364
Amortization of debt issuance costs	99,920	135,236
Minority interest	12,164	(442,336)
Deferred income taxes	10,010,646	(5,851,370)
Unrealized (gains) losses from the change in market value of open derivative contracts	(14,578,784)	21,833,559
Stock-based compensation	287,376	
Gain on sale of assets	(13,869)	
Accretion expense	117,683	71,501
Changes in operating assets and liabilities:		
Accounts receivable	(1,282,731)	(1,227,957)
Income tax refund receivable		(30,783)
Accrued income tax payable		(40,000)
Other current assets	(418,662)	(89,809)
Accounts payable	7,059,955	1,898,020
Other accrued liabilities	474,458	(373,375)
Net cash provided by operating activities	21,313,882	8,418,858
Cash flows used in investing activities:		
Capital expenditures	(58,286,091)	(49,425,468)
Proceeds from sale of other property and equipment	140,410	
Collection of notes receivable	249,012	
Restricted cash		130,243
Other assets	(67,422)	23,387
Net cash used in investing activities	(57,964,091)	(49,271,838)
Cash flows provided by financing activities:		
Debt issuance costs	(339,308)	(114,882)
Dividends		(3,000,000)
Proceeds from exercise of stock options	1,010,962	326,298
Equity offering costs	(2,280,447)	
Proceeds from sales of common stock	81,487,807	
Credit facility borrowings	84,250,000	55,000,000
Proceeds from notes receivable and accrued interest	17,184,357	
Payments on credit facility and other debt	(142,322,661)	(12,576,685)
Net cash provided by financing activities	38,990,710	39,634,731
Effect of exchange rate changes on cash	(32,035)	(4,667)
Increase (decrease) in cash and cash equivalents	2,308,466	(1,222,916)
Cash and cash equivalents at beginning of period	615,806	3,013,723

Cash and cash equivalents at end of period	$	2,924,272	$	1,790,807

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 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. We operate in two segments, natural gas exploration, development and production, almost exclusively within the continental United States and British Columbia and gas marketing in the United States.

The accompanying unaudited consolidated financial statements include our accounts and those of our wholly owned subsidiaries we control and a variable interest entity in which we are the primary beneficiary (See Note 2). 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, 2005 and the accompanying notes included in our registration statement on Form S-1, as amended, which we filed with the Securities and Exchange Commission (the SEC) on July 28, 2006.

On April 13, 2005, GeoMet acquired, through a stock exchange, the minority interest in its 81% owned subsidiary and merged the subsidiary into GeoMet. Following the merger, GeoMet changed its name from GeoMet Resources, Inc. to GeoMet, Inc.

Note 2 Variable Interest Entity

In December 2003, the Financial Accounting Standards Board (the FASB) issued Interpretation No. 46 (revised), *Consolidation of Variable Interest Entities* (FIN 46(R)), which requires variable interest entities to be consolidated by their primary beneficiaries. A primary beneficiary is the party that absorbs a majority of the entity s expected losses or receives a majority of the entity s expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity.

We market all of our gas through Shamrock Energy, LLC (Shamrock), a natural gas marketing entity, under a natural gas purchase contract that, effective March 2006 may be terminated by either party upon 90 days notice. The purchase contract calls for Shamrock to purchase gas from us from our properties covered by the purchase contract, including all of our major properties. Shamrock provides us with several related services, including nominations, gas control, gas balancing, transportation and exchange, market and transportation intelligence, and other advisory and agency services.

On June 14, 2006, we entered into an option agreement with Jon M. Gipson, the president of Shamrock, pursuant to which we have the right, from August 1, 2006 to January 31, 2007, to acquire all of the outstanding equity interests of Shamrock. In exchange for this option, we agreed (i) to extend our gas marketing agreement with Shamrock for a term ending no earlier than January 31, 2007, (ii) to advance, on or before August 1, 2006, $90,000 to Shamrock for working capital purposes during the option period, (iii) to provide any guarantees on behalf of Shamrock, up to an aggregate of $1,500,000, for transactions that Shamrock enters into during the option period that require such guarantees, and (iv) to advance up to an additional $50,000 to Shamrock as may be required to cover certain expenses of Shamrock prior to January 31, 2007, the date on which our option to purchase Shamrock expires. In July 2006, Mr. Gipson acquired all of the outstanding equity interest of Shamrock from Optigas, the parent of Shamrock, for $1.00. In August 2006, we advanced Shamrock $90,000 for working capital purposes, and we issued two guarantees, totaling $1,160,000, to Shamrock s customers in accordance with the option agreement. As of the date of this filing, the guarantees have not been called, and the advance is still outstanding. Although we are the primary beneficiary of this variable interest entity, the creditors of Shamrock do not have recourse against our

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general credit, and our losses are limited to our exposure under the guarantee and the $90,000 advance.

In the event that we exercise the Shamrock option, we will be obligated to provide Mr. Gipson an at-will employment position with us at an annual salary of not less than $130,000, and we will also pay Mr. Gipson an amount equal to 50% of the net profits generated by Shamrock from August 1, 2006 through the date that we elect to exercise the option, up to January 31, 2007. No additional consideration is due upon our exercise of the Shamrock option. In the event we do not exercise the option by January 31, 2007 and Mr. Gipson continues to operate Shamrock after the end of the option period, Shamrock will retain 100% of the net profits generated during the option period, all guarantees that we have entered into on behalf of Shamrock will terminate on January 31, 2007, and Shamrock will repay us all funds that we advanced to Shamrock in equal monthly payments, without interest, over an 18-month period. If we do not exercise the option by January 31, 2007 and Mr. Gipson elects not to continue to operate Shamrock, Mr. Gipson will wind up the affairs of Shamrock within 90 days after the end of the option period, and we will receive 100% of the net profits from Shamrock s operations during the wind-up period and the proceeds from the liquidation of Shamrock s assets, until we have been repaid all funds that we advanced to Shamrock and all guarantees that we entered into on behalf of Shamrock have been terminated and released.

In accordance with FIN 46(R), we consolidated Shamrock into our financial statements, effective August 1, 2006. We do not have any voting interest in Shamrock and as a result the consolidation of Shamrock did not have a material impact on our results of operations for the three and nine months ended September 30, 2006. Other than the Shamrock customers that we have provided guarantees to on behalf of Shamrock, the remainder of Shamrock s customers have no recourse against us. Our losses are limited to the current advance of $90,000 and the amounts outstanding under the existing guarantee ($1,160,000) which have not been recorded as of September 30, 2006. As of September 30, 2006, $3,209,419 of assets and $3,209,419 of liabilities have been included in our unaudited consolidated balance sheet as a result of applying FIN 46(R) to Shamrock, a variable interest entity. Over 99 per cent of the assets and liabilities are current.

Note 3 Recent Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes. The interpretation prescribes a two-step process in the recognition and measurement of a tax position taken or expected to be taken in a tax return. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination by taxing authorities. If this threshold is met, the second step is to measure the tax position on the balance sheet by using the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. FIN 48 also requires additional disclosures. FIN 48 is effective prospectively for fiscal years beginning after December 15, 2006. We are currently evaluating the impact that FIN 48 will have on our operations and financial condition.

In September 2006, the FASB issued FASB No. 157, *Fair Value Measurements* (FASB 157). FASB 157 establishes a single authoritative definition of fair value sets out a framework for measuring fair value 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 are currently evaluating the impact that adopting FASB 157 will have on our operations and financial condition.

In September 2006, the SEC released Staff Accounting Bulletin 108 (SAB 108). SAB 108 provides interpretative guidance on how the effects of a carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. SAB 108 is effective for fiscal years ending after November 15, 2006. We are currently evaluating the impact that adopting SAB 108 will have on our operations and financial condition.

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Note 4 Net Income Per Share

Net Income (loss) 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. No dilution for any potentially dilutive securities is included. 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 September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
Net income (loss) per share:				
Basic-net income per share	$ 0.11	$ (0.41)	$ 0.40	$ (0.40)
Diluted-net income per share	$ 0.11	$ (0.41)	$ 0.39	$ (0.40)
Numerator				
Net income available to common stockholders basic	$ 4,227,529	$ (11,342,639)	$ 13,681,847	$ (10,977,192)
Denominator:				
Weighted average shares outstanding-basic	36,921,141	27,664,973	33,799,293	27,555,076
Add potentially dilutive securities:				
Stock options	849,312		1,002,286	
Dilutive securities	37,770,453	27,664,973	34,801,578	27,555,076

Note 5 Gas Properties

The Company uses the full cost method of accounting for its 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, the Company capitalizes interest expense, direct general and administrative expenses, direct stock-based compensation expense, and additions resulting from asset retirement liabilities. 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 and 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. At September 30, 2006, the net capitalized costs exceeded the ceiling limitation by approximately $1,579,000. However, as allowed by the Securities and Exchange Commission guidelines, since gas prices have significantly increased subsequent to quarter end no charge to operations were required as of September 30, 2006.

Note 6 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 if a reasonable estimate of the fair value of an obligation can be made. 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 the abandonment obligation was incurred using an assumed cost of funds for GeoMet. Once the ARO is recorded, it is then accreted to its estimated future value using the same assumed cost of funds.

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The following table details the changes to our asset retirement liability for the nine months ended September 30, 2006:

Asset retirement obligation at beginning of year	$ 1,890,173
Liabilities incurred	327,503
Liabilities settled	(33,680)
Accretion	132,310
Revisions in estimates	(39,021)
Foreign currency translation	6,327
Asset retirement obligation at end of period	2,283,612
Less: current portion of obligation	52,726
Long-term asset retirement obligation	$ 2,230,886

Note 7 Price Risk Management Activities

We engage in price risk management activities from time to time. These activities are intended to manage our exposure to fluctuations in the price of natural gas. We utilize derivative financial instruments, primarily three-way 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.

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, 2006, we recognized gains on derivative contracts of $4,685,603 and $14,974,055 including realized gains of $551,475 and $395,271, respectively. During the three and nine months ended September 30, 2005, we recognized losses on derivative contracts of $21,316,030 and $24,122,283 including realized losses of $2,152,429 and $2,288,724, respectively.

At September 30, 2006 and at December 31, 2005, the fair values of open derivative contracts were assets and liabilities of approximately $3.0 million and $11.5 million, respectively.

As of September 30, 2006, 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.

Instrument Type	Production Period	Volumes (MMBtu)	Weighted Average Floor Prices ($/MMBtu)			Weighted Average Cap Prices ($/MMBtu)	
Collars (3 way)	Summer 2006	372,000	$	5.88	$7.00	$	8.49
Collars (3 way)	Winter 2006/2007	1,510,000	$	6.70	$8.20	$	11.02
Collars (3 way)	Summer 2007	1,712,000	$	5.75	$7.38	$	10.50
Collars (3 way)	Winter 2007/2008	1,216,000	$	6.00	$9.00	$	14.80
Collars (3 way)	Summer 2008	1,712,000	$	5.00	$7.00	$	10.50

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Note 8 Long-Term Debt

The following is a summary of our long-term debt at September 30, 2006 and December 31, 2005:

	September 30, 2006	December 31, 2005
Borrowings under bank credit facility	$ 41,000,000	$ 99,000,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	210,227	243,166
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	140,517	146,571
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	589,445	623,113
Total debt	41,940,189	100,012,850
Less current maturities included in current liabilities	(92,887)	(86,472)
Total long-term debt	$ 41,847,302	$ 99,926,378

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 credit agreement (as amended), 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, 2006, the borrowing base under the bank credit facility was $150 million of which $41 million of borrowings were outstanding, resulting in a borrowing availability of $109 million. For the nine months ended September 30, 2006 we borrowed $84.3 million and made payments of $142.3 million under the credit facility. As of September 30, 2006, 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, which is never less than 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, 2006, we were in compliance with all of the covenants in the credit agreement. The bank credit facility matures on January 6, 2011.

Note 9 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 at December 31, 2005 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, we completed a private equity offering of 10,000,000 shares of our common stock, consisting of 2,067,023 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 $25.0 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. In connection with the private equity offering, we sold an additional 250,000 shares of our common stock to qualified institutional buyers on February 7, 2006, from which we received aggregate consideration

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of approximately $3.0 million, or $12.09 per share, pursuant to the initial purchaser s option to purchase additional shares. We used the net proceeds generated from this sale to repay a portion of the borrowings under our bank credit facility and for general corporate purposes.

On July 27, 2006, the SEC declared effective our registration statement on Form S-1 (Registration No. 333-131716), which registered for 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, the SEC declared effective our registration statement on Form S-1 (Registration No. 333-134070), which registered 5,750,000 shares of our common stock for sale in an underwritten initial public offering. The 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 the 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, 2006, a total of 584,978 shares of common stock were issued upon the exercise of stock options.

Note 10 Stock Options

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* (SFAS 123R), 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, 2006, 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, but we will continue to issue shares of our common stock upon exercise of awards that we have previously granted under the 2005 Stock Option Plan.

In 2001, GeoMet established a stock option plan that authorized the granting of options to key employees. The exercise price of each option granted pursuant to the 2001 Plan was not less than 100% of the fair market value of a share of common stock on the date the option was granted. The options granted under the 2001 Plan have a term of seven years. Prior to the effective date of our merger with our majority-owned subsidiary, options granted pursuant to the 2001 Plan entitled the holder to acquire shares of GeoMet s majority-owned subsidiary. Effective with the merger of the majority-owned subsidiary into GeoMet, all of the outstanding options under the 2001 Plan became fully vested and were exchanged for options to acquire common stock of GeoMet under the 2005 Stock Option Plan. There will be no future grants of awards under the 2005 Stock Option Plan.

The 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. The maximum number of shares available for grant under this plan is 2,000,000. The 2006 Long-Term Incentive Plan is available to our employees and independent directors and is designed to (1) attract and retain employees and independent directors, (2) further align their interest with shareholder interest and (3) closely link compensation with GeoMet s 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 have a term of seven years, vest evenly over three years, except for awards that are performance based. Performance based awards vest when the performance criteria has been met.

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Incentive Stock Options

The table below summarizes incentive stock option activity for the nine months ended September 30, 2006:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2005	893,324	$ 2.55	3.60	
Granted	150,945	13.00	6.90	
Forfeited	15,000			
Exercised	424,978	$ 1.44		
Outstanding at September 30, 2006	604,291	$ 5.82	4.24	$ 2,707,837
Options exercisable at September 30, 2006	402,346	$ 2.89	3.17	$ 2,707,837

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

Non-Qualified Stock Options

In conjunction with the sale of common stock to certain of our executive officers during 2000, we granted these officers options to acquire 400,000 shares of common stock of GeoMet at $2.50 per share. The holders of the options also had a right to be issued additional options to acquire five percent of any additional common stock issued at a price of $2.50 per share. The executive officers were issued options to acquire 600,000 shares in conjunction with the issuance of 12,000,000 common shares in 2003 and were issued options to acquire 200,000 shares in conjunction with the issuance of 4,000,000 common shares in 2004. The options have a term of 10 years and are fully vested and exercisable.

The table below summarizes non-qualified stock option activity for the nine months ended September 30, 2006:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2005	1,200,000	$ 2.50	5.96	
Granted	73,865	13.00	6.90	
Forfeited				
Exercised	160,000	$ 2.50		
Outstanding at September 30, 2006	1,113,865	$ 3.14	6.39	$ 7,211,520
Options exercisable at September 30, 2006	1,040,000	$ 2.50	6.39	$ 7,211,520

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

During the three months ended March 31, 2006, we recorded a compensation expense accrual in the amount of $205,923 for an employee who exercised his options via a cashless exercise with no mature shares on the date of exercise. The total compensation expense accrual was then allocated to the full cost pool and lease operating expenses in the amount of $102,961 and $102,962, respectively.

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During the three months ended June 30 2006, we granted share-based option awards to our independent directors (8,000 options under the 2006 Plan), executive officers and key employees (65,865 performance-based non-qualified options and 12,249 shares of restricted stock under the 2006 Plan) and executive officers and key employees (150,945 incentive stock options under the 2006 Plan). We recorded a compensation accrual of $120,301, ($2,041 charged to lease operating expense, $92,669 charged to general and administrative expense, $16,068 capitalized in the domestic full cost pool, and $9,523 capitalized to unevaluated gas properties). A related income tax benefit of $19,541 was also recorded. The future compensation cost associated with these awards, totaling $605,555 will be amortized over the vesting period of such options. Compensation cost related to share based awards is determined using the fair value method as described above. Significant assumptions used in determining the compensation cost include an expected term of 4.5 years, volatility of 36.95%, a risk free interest rate of 4.87%, and no expected dividends. The performance criteria of the performance-based options and restricted stock awards include attaining certain levels of production, natural gas reserves, and net income. None of the goals have been achieved as of September 30, 2006.

During the three months ended September 30, 2006, we recorded a compensation accrual of $136,395 and a related income tax benefit of $29,770.

The following table illustrates the approximate pro forma effect on net income and earnings per share assuming the stock-based compensation expense under APB 25 had been recorded using fair value methods at date of grant for the following prior periods:

	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
Net loss as reported	$ (11,342,639)	$ (10,977,192)
Less stock-based compensation expense determined under fair value based methods, net of tax	(4,787)	(49,583)
Pro forma net loss	$ (11,347,426)	$ (11,026,775)
Net loss per share:		
Basic as reported	$ (0.41)	$ (0.40)
Basic pro forma	$ (0.41)	$ (0.40)
Diluted-as reported	$ (0.41)	$ (0.40)
Diluted-pro forma	$ (0.41)	$ (0.40)

Significant assumptions, based on the premise that we were a private entity in 2005, that were used in determining the compensation costs for the above table included a dividend yield of 0%, expected volatility of 0%, risk-free interest rate of 3.4%, and an expected life three years.

Note 11 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. As of September 30, 2006, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

El Paso Overriding Royalty Interest Dispute

We filed a claim on June 9, 2004 against El Paso Production Company (El Paso), CMV Joint Venture and CDX Minerals, LLC (CDX) seeking a declaratory judgment of its rights under a joint operating agreement covering certain properties in White Oak Creek. We had previously entered into an agreement to sell its interest to CDX, subject to a preferential right to purchase held by El Paso, which El Paso subsequently exercised. A dispute arose as to whether the preferential right granted under the agreement applied to overriding royalty interests and other related interests. We have asserted that the preferential right to purchase does not include overriding royalty

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interests, and that we are entitled to retain all overriding royalty interests we possess under the agreement. The trial court rendered judgment in our favor, and El Paso has appealed the decision of the trial court. Oral argument was held on October 11, 2006 at the Dallas Court of Appeals. A decision from that court has not yet been entered. While we believe that we are entitled to retain these interests, a judgment against us would result in it being required to sell the overriding royalty interest to El Paso for a price of approximately $10.5 million; however, this amount would be reduced by any proceeds we have received from production since the effective date of the sale.

CNX Surface Use Dispute

We and Pocahontas Mining Limited Liability Company (PMC) filed a claim in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX Gas Company LLC (CNX) seeking a temporary and permanent injunction, as well as a declaration of our rights under a right-of-way agreement that we entered into with PMC, the surface owner. We are in the process of constructing a 12-mile pipeline, a portion of which traverses this right-of-way to connect with and transport our gas to the Jewell Ridge Pipeline. We have completed construction of the pipeline for the portion across the disputed right-of-way. CNX claimed that it has the exclusive right to transport gas across the acreage in question and that our right-of-way is invalid. CNX also gated certain access roads to the acreage and requested that we remove our contractor s equipment from the property. The Circuit Court of Buchanan County, Virginia conducted evidentiary hearings on June 15, 2006 and July 6, 2006. At the hearings the court ordered CNX to allow us and PMC access to the property over and across the existing roads and directed the parties to prepare a scheduling order setting forth the timelines for discovery and setting the trial date for this matter for November 15, 2006. The trial date has been reset for April 17 and 18, 2007. 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.

We believe that our right-of-way agreement is valid and enforceable and that we will prevail in the lawsuit; however, in the event we are unsuccessful in obtaining a favorable declaratory judgment, we may be required to construct an alternate pipeline at a cost in excess of $12 million, change the planned route of the pipeline we are currently constructing at a cost that could add more than $5 million to the cost of construction of the pipeline, pay CNX an access fee for any gas transported across the PMC property at a rate up to 3.5% of the gross proceeds from the sale of such gas, or seek other transportation alternatives through pipelines owned by third parties. We do not know what the cost of other transportation alternatives with third parties would be at this time, but we believe that such cost would be significantly in excess of the costs related to the construction and operation of our own pipeline. Any of these alternatives may result in our inability to deliver our gas from the Pond Creek field to market for an extended period of time. If we are unable to deliver its gas to market for a prolonged period of time, our financial position, results of operations and cash flow will be materially adversely affected.

Note 12 Segment Information

We are engaged in the exploration, development and production of natural gas from coal seams (coal bed methane) primarily in the United States and Canada. The variable interest entity consolidation during the current quarter (see Note 2) added a gas marketing activity that added a second reportable segment to our core business of natural gas exploration, development and production.

Using guidelines set forth in SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we have identified two reportable segments; (1) exploration, development and production of natural gas and (2) marketing natural gas.

Information concerning our business activities is summarized as follows:

	Natural Gas Exploration & Production	Marketing Natural Gas	Eliminations	Total
As of and for the three months ended September 30, 2006:				
Revenues from external customers	$ 10,968,436	$ 5,028,774	$	$ 15,997,210
Intersegment revenues	9,099,016		(9,099,016)	
Operating income (loss)	7,790,814	(31,419)		7,759,395
Total assets	$ 310,286,808	$ 7,735,686	(4,526,267)	$ 313,496,227

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	Natural Gas Exploration & Production	Marketing Natural Gas	Eliminations	Total
As of and for the nine months ended September 30, 2006:				
Revenues from external customers	$ 33,419,380	$ 5,028,774	$	$ 38,448,154
Intersegment revenues	9,099,016		(9,099,016)	
Operating income (loss)	26,085,525	(31,419)		26,054,106
Total assets	$ 310,286,808	$ 7,735,686	(4,526,267)	$ 313,496,227

All sales and operating income occurred in the United States. Natural gas exploration and production capital expenditures were $55,038,168 in the United States and $3,247,923 in Canada. Marketing natural gas is not capital intensive and there were no capital expenditures. We sell all of our gas production to the variable interest entity that is our natural gas marketing segment. One natural gas marketing customer accounted for approximately 18% of the total consolidated revenues for the nine months ended September 30, 2006.

Note 13 Related Party Transactions

On July 21, 2003, we loaned our chief financial officer $250,000 to provide liquidity in connection with a divorce settlement so that he could retain ownership of his common stock. The full recourse loan accrued interest at an annual rate of 5.87%. The note was paid in full on January 2006 concurrent with the private equity offering discussed in Note 9.

Note 14 Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of the SFAS 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 bases of assets and liabilities using enacted tax rates at the end of the period. Under SFAS 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 Internal Revenue Code Section 382. We have a significant deferred tax asset associated with net operating loss carryforwards (NOLs). It is more likely than not that we will use these NOLs to offset current tax liabilities in future years.

Deferred income tax expense was increased by $405,722 for the nine months ended September 30, 2006 because of certain state taxes not previously included in prior periods.

On May 18, 2006, the Governor of Texas signed into law House Bill 3 (HB-3), which modifies the existing Texas franchise tax law. The modified franchise tax will be computed by subtracting either costs of goods sold or compensation expense, as defined in HB-3, from gross revenue to arrive at a gross margin. The resulting gross margin will be taxed at a one percent tax rate. HB-3 becomes effective for activities occurring on or after January 1, 2007. We believe that this tax should still be accounted for as an income tax, following the provisions of SFAS 109, because it has the characteristics of an income tax. For the three and nine months ended September 30, 2006, we believe that the impact of this modified tax is not significant.

Note 15 Subsequent Event

In October 2006, we executed of a series of agreements with a privately held company affecting operations in the Gurnee field in the Cahaba Basin of Alabama. Under the agreements, we will dispose of produced water from that company s operations in the Gurnee field in an amount up to one half of the capacity of our water disposal pipeline. The current capacity of the water disposal pipeline is approximately 30,000 barrels per day with a design capacity estimated to be 45,000 barrels per day. Fees for water disposal under the agreements will initially be $0.35 per barrel of water but will decline to $0.20 per barrel of water within six months. Such fees will be used to reduce

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our field operating costs.

Additionally, under these agreements, we have secured firm capacity rights on a high pressure gas gathering pipeline which connects into Enbridge s Magnolia Pipeline System. The acquired rights entitle us to transport approximately 40 million cubic feet per day of coalbed methane gas at a fee of $0.05 per MMbtu actually gathered through the pipeline. We do not anticipate utilizing this capacity in the immediate future. This agreement provides us with a second outlet for our gas produced from the Gurnee field. Together with our existing capacity on the Southern Natural Gas Bessemer Calera lateral, our total gas takeaway capacity is expected to meet all of our future requirements.

Finally, as part of the agreements, we received an assignment of 1,360 acres of undeveloped leasehold contiguous with our existing leasehold positions.

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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, 2005, which are included in our final prospectuses that we filed with the SEC on July 28, 2006.

Overview

We are an independent natural gas producer involved in the exploration, development, and production of natural gas from coal seams (coalbed methane or CBM). Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the Appalachian Basin in West Virginia and Virginia. As of September 30, 2006, we control a total of approximately 277,000 net acres of coalbed methane development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia. We operate in two segments, natural gas exploration, development and production, almost exclusively within the continental United States and British Columbia and gas marketing in the United States.

We have been very active in North America for over 20 years as an operator of CBM fields owned by us, as a contract operator of CBM fields in which we owned an interest, and as a consultant or contract operator for CBM fields owned by other companies. Over the last five years, we have focused on expanding the number of projects that we own and operate. This focus resulted in the initial development of our two primary producing properties, the Gurnee field in the Cahaba Basin and the Pond Creek field in the Appalachian Basin. Additionally, we own and operate several active exploration projects. This change in focus of our operations has also resulted in a significant increase in our business, ranging from capital expenditures to headcount.

The variable interest entity consolidation during the current quarter (see Note 2 of the unuadited consolidated financial statements) added a gas marketing activity that resulted in a second reportable segment to our core business of natural gas exploration, development and production.

On January 30, 2006, we sold 2,067,023 shares of common stock in a private placement to qualified institutional buyers pursuant to Rule 144A under the Securities Act. In connection with this offering, on February 7, 2006, we sold an additional 250,000 shares of our common stock to qualified institutional buyers under Rule 144A under the Securities Act pursuant to the initial purchaser s option to purchase additional shares. We used the net proceeds from our private placement of common stock of approximately $27 million and the receipt of approximately $17.5 million from the repayment of certain stockholder loans and from the exercise of stock options by certain of the selling stockholders to reduce outstanding borrowings under our bank credit facility and for general corporate purposes.

On August 2, 2006, we sold 5,750,000 shares of common stock in an initial public offering. We received net proceeds from the offering of approximately $52.6 million, after deducting estimated offering expenses and underwriting discounts and commissions, and used the net proceeds from the offering to reduce outstanding borrowings under our bank credit facility.

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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, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas prices, and, therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes, 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, 2006, gas sales quantities increased by 448.9 MMcf and 1,222 MMcf from the comparable periods in the prior year to 1,655 MMcf and 4,501 MMcf, respectively. The increase in sales was related to the continued development of our Cahaba and Pond Creek fields. Average gas sales prices for the three months ended September 30, 2006 decreased by $2.11 per Mcf from the prior year period to $6.63 per Mcf, while average gas sales prices for the nine months ended September 30, 2006 increased $0.04 per Mcf from the prior year period of $7.43 to Mcf.

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. Our policy is to enter into hedging transactions which increase our probability of achieving our targeted level of cash flows. As a result of these hedging positions, we had unrealized gains in the amount of $4.1 million and $14.6 million for the three and nine months ended September 30, 2006, respectively, compared to an unrealized losses of $19.2 and $21.8 million for the three months and nine months ended September 30, 2005.

We believe that our cash flow from operations and other financial resources such as borrowings under our credit facility, proceeds from our initial public equity offering that closed on August 2, 2006, 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.

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, 2006.

Future Charges

Public Company Expenses

We believe that our general and administrative expenses will increase now that we are a publicly traded company. This increase will consist of legal and accounting fees and additional expenses associated with compliance with the Sarbanes-Oxley Act of 2002 and other regulations. We anticipate that our ongoing general and administrative expenses will also increase as a result of being a publicly traded company. This increase will be due primarily to the cost of accounting support services, filing annual and quarterly reports with the SEC, investor relations, directors fees, directors and officers insurance, and registrar and transfer agent fees. As a result, we believe that our general and administrative expenses for 2006 will increase significantly over the prior year.

Stock Compensation

Effective January 1, 2006, we adopted the fair value recognition provisions of Statement of Financial Accounting Standards (SFAS) No. 123R, *Share-Based Payments* (SFAS 123R), using the prospective transition method. Due to the adoption of SFAS 123R, we expect our compensation expense related to the granting of share-based awards subsequent to adoption to be higher than in prior periods. As of September 30, 2006, future compensation expense totaled $605,555 for awards granted subsequent to January 1, 2006. For awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before

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adoption. Therefore, no equity compensation cost will be recognized on these awards in the future unless such awards are modified, repurchased, or cancelled.

Derivative Instruments

Due to the historical volatility of natural gas prices, we have implemented a hedging strategy aimed at reducing the variability of prices we receive for our sales. Currently, we use collars and fixed-price 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 if we were not a party to derivative instruments in times of rising natural gas prices. If commodity prices increase, we may recognize additional charges in future periods; however, for the three and nine months ended September 30, 2006 prices decreased, and we recognized a total gain on derivative contracts in the amount of $4.7 million and $15.0 million, respectively. The three months ended September 30, 2006 total gain consisted of $4.1 million unrealized gain and $0.6 million realized gain while the nine months ended September 30, 2006 total gain consisted of $14.6 unrealized gain and $0.4 realized gain.

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, 2006 and 2005. This table should be read with the discussion of the results of operations for the periods presented below.

	Three Months Ended		Nine Months Ended	
	September 30,			
	2006	2005	2006	2005
	(In thousands except for per Mcf)			
Gas sales	$ 10,968	$ 10,542	$ 33,419	$ 24,240
Lease operating expenses	$ 2,510	$ 2,317	$ 8,184	$ 6,212
Compression and transportation expenses	$ 1,041	$ 851	$ 3,172	$ 2,332
Production taxes	$ 259	$ 231	$ 765	$ 518
Total production expenses	$ 3,810	$ 3,399	$ 12,121	$ 9,062
Net sales volumes (MMcf)	1,655	1,206	4,501	3,279
Pond creek field	1,000	766	2,783	2,088
Gurnee field	547	321	1,386	1,368
Per Mcf data ($/Mcf):				
Average natural gas sales price	$ 6.63	$ 8.74	$ 7.43	$ 7.39
Average natural gas sales price realized(1)	$ 6.96	$ 6.95	$ 7.51	$ 6.69
Lease operating expenses	$ 1.52	$ 1.92	$ 1.82	$ 1.89
Pond creek field	$ 1.13	$ 1.42	$ 1.37	$ 1.47
Gurnee field	$ 2.52	$ 3.80	$ 3.14	$ 3.75
Compression and transportation expenses	$ 0.63	$ 0.71	$ 0.70	$ 0.71
Pond creek field	$ 0.84	$ 0.94	$ 0.94	$ 0.94
Gurnee field	$ 0.36	$ 0.41	$ 0.39	$ 0.42
Production taxes	$ 0.16	$ 0.19	$ 0.17	$ 0.16
Pond creek field	$ 0.01	$ 0.03	$ 0.02	$ 0.02
Gurnee field	$ 0.37	$ 0.49	$ 0.42	$ 0.42
Total production expenses	$ 2.31	$ 2.82	$ 2.70	$ 2.76
Pond creek field	$ 1.98	$ 2.39	$ 2.33	$ 2.45
Gurnee field	$ 3.25	$ 4.70	$ 3.95	$ 4.59
Depreciation, depletion and amortization	$ 1.31	$ 0.85	$ 1.28	$ 1.03

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

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Results of Operations   Natural Gas Production

Three Months Ended September 30, 2006 compared with Three Months Ended September 30, 2005

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, 2006	2005	Change
	(In thousands)		
Gas sales	$ 10,968	$ 10,542	4%
Operating fees and other		4	(100)%
Total revenues	$ 10,968	$ 10,546	4%
Lease operating expenses	$ 2,510	$ 2,318	8%
Compression and transportation expenses	1,041	851	22%
Production taxes	259	231	12%
Depreciation, depletion and amortization	2,168	1,029	111%
Research and development	16	211	(92)%
General and administrative	1,868	721	159%
Realized losses (gains) on derivative contracts	(551)	2,152	NM
Unrealized (gains) from the change in market value of open derivative contracts	(4,134)	19,164	NM
Total operating expenses	$ 3,177	$ 26,677	(88)%
Income (loss) from natural gas production	$ 7,791	$ (16,131)	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $0.426 million, or 4%, to $11 million compared to the prior year quarter. The increase in gas sales was primarily a result of increased production, which was partially offset by decreased average sales prices. Production increased 37% while average gas prices decreased 24%, excluding hedging transactions. The $0.426 million increase in gas sales consisted of a $3.5 million decrease in prices and a $3.9 million increase in production. The increase in production was principally attributable to our Cahaba and Pond Creek development activities.

Lease operating expenses. Lease operating expenses increased by $0.192 million, or 8% to $2.5 million. The increase in lease operating expenses consisted of $0.862 million increase in production and $0.668 million decrease in costs. The decrease in costs is related to a decrease in well service activities compared to the prior year quarter.

Compression and transportation expenses. Compression and transportation expenses increased by $0.190 million, or 22% to $1 million. The $0.190 million increase in compression and transportation expenses consisted of a $0.317 million increase in production and a $0.127 million decrease in costs. The decrease in costs is related to a decrease in well service activities on our compressors compared to the prior year quarter.

Production taxes. Production taxes increased by $0.029 million, or 12%, to $0.260 million. The production taxes increase of $0.029 million was primarily due to increased production, partially offset by decreasing average gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $1.1 million, or 111%, to $2.2 million. The depreciation, depletion and amortization increase of $1.1 million consisted of a $0.383 million increase in production and $0.756 million increase in the depletion rate. The increase in the depletion rate was primarily due to higher costs relative to proved reserves added.

General and administrative. General and administrative expenses increased by $1.1 million or, 159%, to $1.8 million. The increase in general and administrative expenses was a result of increases in employee expenses (39%), professional services (978%), director and investor relations (100%), insurance expense (361%), and office expenses and business taxes (64%). This increase was partially offset by increased capitalized general and administrative expenses (20%) and field and operating overhead recoveries (45%). The largest dollar increase was in professional services that resulted from the increased audit, Sarbanes Oxley, tax, and legal services and employee expenses. The increase in general and administrative expenses was a result of expanding the overhead structure to support our growth and increased costs of being a public company.

Realized losses (gains) on derivative contracts. Realized gains on derivative contracts increased by $2.7 million to $0.551 million compared to a loss of $2.2 million in the prior corresponding period. 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 $4.1 million gain as compared to a $19.2 million loss in the comparable period in 2005. 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 value of derivative liabilities increase. The $4.1 million gain was a result of decreased future commodity gas prices.

Nine Months Ended September 30, 2006 compared with Nine Months Ended September 30, 2005

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, 2006	Nine Months Ended September 30, 2005	Change
	(In thousands)		
Gas sales	$ 33,419	$ 24,240	38%
Operating fees and other		376	(100)%
Total revenues	$ 33,419	$ 24,616	36%
Lease operating expenses	$ 8,184	$ 6,212	32%
Compression and transportation expenses	3,172	2,331	36%
Production taxes	765	519	47%
Depreciation, depletion and amortization	5,749	3,378	70%
Research and development	115	531	(78)%
General and administrative	4,324	2,277	90%
Realized losses (gains) on derivative contracts	(395)	2,289	NM
Unrealized losses (gains) from the change in market value of open derivative contracts	(14,579)	21,833	NM
Total operating expenses	$ 7,335	$ 39,370	NM
Income (loss) from natural gas production	$ 26,084	$ (14,754)	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $9.2 million, or 38%, to $33.4 million compared to the prior year nine-month period. The increase in gas sales was a result of increased production and average gas prices. Production increased 37% while average gas prices, excluding hedging transactions, increased 0.54%. The $9.2 million increase in gas sales consisted of a $0.2 million increase in prices and a $9.0 million increase in production. The increase in production was principally attributable to our Cahaba and Pond Creek development activities.

Lease operating expenses. Lease operating expenses increased by $2.0 million, or 32% to $8.2 million. The $2.0 million increase in lease operating expenses consisted of $2.3 million increase in production and $0.3 decrease in costs. The decrease in costs is related to a decrease in well service activities from the prior year period.

Compression and transportation expenses. Compression and transportation expenses increased by $0.841 million, or 36% to $3.2 million. The $0.841 million increase in compression and transportation expenses consisted

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of a $0.869 million increase in production and a $0.028 million decrease in costs. The decrease in costs is related to a decrease in well service activities on our compressors compared to the prior year period.

Production taxes. Production taxes increased by $0.246 million, or 47%, to $0.764 million. The production taxes increase of $0.246 million was primarily due to increased production.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $2.4 million, or 70%, to $5.7 million. The depreciation, depletion and amortization increase of $2.4 million consisted of a $1.1 million increase in depletion rate and a $1.3 million increase in production. The increase in the depletion rate was primarily due to $48.0 million added to the net book value of gas properties due to a purchase accounting adjustment related to the acquisition of the minority interest stock in a subsidiary.

General and administrative. General and administrative expenses increased by $2.0 million or 90%, to $4.3 million. The increase in general and administrative expenses was a result of increases in employee expenses (29%), professional services (345%), director and investor relations expenses (100%), insurance expense (72%) and office expenses and business taxes (40%). This increase was partially offset by increased capitalized general and administrative expenses (4%) and field and operating overhead recoveries (18%). The largest dollar increase was in employee expenses and professional services that resulted from the increased audit, Sarbanes Oxley, tax and legal services. The increase in general and administrative expenses was a result of expanding the overhead structure to support our growth and increased costs of being public company.

Realized losses (gains) on derivative contracts. Realized gains on derivative contracts increased by $2.7 million to $0.4 million compared to a loss of $2.3 million in the prior corresponding period. 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 generated a $14.6 million gain as compared to a $21.8 million loss in the comparable period in 2005. 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 value of derivative liabilities increase. The $14.6 million gain was a result of decreased future commodity gas prices.

Results of Operations Marketing Natural Gas

Three and Nine Months Ended September 30, 2006 compared with Three and Nine Months Ended September 30, 2005

The variable interest entity consolidation during the current quarter (see Note 2 of the unaudited consolidated financial statements) added a gas marketing activity that added a second reportable segment to our core business of natural gas exploration, development and production.

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

	Three and Nine Months Ended September 30, 2006	2005	Change
	(In thousands)		
Gas marketing	$ 5,029	$	(100)%
Purchased gas	4,976		(100)%
Gross Margin	53		(100)%
General and administrative expenses	84		
Loss from marketing natural gas	$ (31)	$	(100)%

The loss from marketing natural gas is after elimination of inter-segment profit of $51,727.

Results of Operations Corporate

Three Months Ended September 30, 2006 compared with Three Months Ended September 30, 2005

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) decreased by $0.315 million, or 30%, to $0.738 million. The decrease was primarily due to lower outstanding bank balances, which was partially offset by higher interest rates. The decrease in interest expense was offset by decreased capitalization of interest expense with respect to our unevaluated gas properties. Capitalized interest totaled $0.202 million for the three months ended September 30, 2006.

Income tax expense (benefit). Income tax expense increased by $8.6 million, or 147%, to $2.8 million. The increase in income tax expense in the current quarter was due to (1) the pretax income position versus a pretax loss position in the comparable prior period and (2) an increase in the effective tax rate for the current quarter to 40% from 34% in the comparable prior period as a result of certain state taxes not previously included in prior periods.

Nine Months Ended September 30, 2006 compared with Nine Months Ended September 30, 2005

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) decreased by $0.166 million, or 7%, to $2.4 million. The decrease was primarily due to lower outstanding bank balances and was partially offset by higher interest rates. Capitalized interest totaled $0.845 million for the nine months ended September 30, 2006.

Income tax expense (benefit). Income tax expense (benefit) resulted in an expense of $10.0 million in the nine months ended September 30, 2006 compared to a benefit of $5.8 million in the comparable prior period in 2005. The increase in income tax expense in the current nine month period was due to (1) the pretax income position versus a pretax loss position in the comparable prior period and (2) an increase in the effective tax rate for the current quarter to 42% from 34% in the comparable prior period as a result of certain state taxes not previously included in prior periods and the related cumulative non-cash adjustment of $0.406 million. Excluding the state tax revision, the revised estimated effective tax rate for the year is expected to be approximately 40.1%.

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flow from operations for the nine months ending September 30, 2006 and 2005 were $21.3 million and $8.4 million, respectively. Cash flow from operations of $21.3 million for the nine months ended September 30, 2006, combined together with net cash provided by financing activities of $39.0, were sufficient to fund net cash used in investing activities of $58 million, which primarily includes capital expenditures for the exploration and development of our gas properties. Net cash provided by financing activities includes $81.5 million related to the initial public offering in August 2006 and a private equity offering in January 2006. Also, net cash provided by financing activities includes net payments on our credit facility and other debt of $58.1 million.

As of September 30, 2006 and December 31, 2005, we had a working capital deficit of approximately $7.3 million and $7.4 million, respectively. At September 30, 2006, we had adequate cash flows from operating activities

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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, proceeds from the initial public offering that concluded on August 2, 2006 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.

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 through the use of commodity price swap agreements and costless collar arrangements. 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. We have at times hedged forward for periods of more than two years. We generally limit the amount of these hedges during periods of relatively high financial leverage to no more than 50% to 60% of the then expected gas production for such future period. 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. Currently, our hedge strategy favors the use of three-way collars that allow us to retain more price upside. We have not designated any of our price risk management activities as accounting hedges and, therefore, 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. Until 2005, the impact of this method of accounting was not significant; however, the significant increase in gas prices in 2005, particularly in the third quarter of 2005 in response to Hurricanes Katrina and Rita resulted in significant unrealized losses. More recently, the decrease in gas prices has created significant unrealized gains. The unrealized gains and losses have no impact on cash flows.

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*. During the three and nine months ended September 30, 2006, natural gas prices decreased and we recognized a total gain on derivative contracts in the amount of $4.7 million and $15 million, respectively. The three months ended September 30, 2006 total gain consisted of $4.1 million unrealized gain and $0.6 million realized gain while the nine months ended September 30, 2006 total gain consisted of $14.6 million unrealized gain and $0.4 million realized gain.

As of September 30, 2006, 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.

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Instrument Type	Production Period	Volumes (MMBtu)	Weighted Average Floor Prices ($/MMBtu)			Weighted Average Cap Prices ($/MMBtu)	
Collars (3 way)	Summer 2006	372,000	$	5.88	$7.00	$	8.49
Collars (3 way)	Winter 2006/2007	1,510,000	$	6.70	$8.20	$	11.02
Collars (3 way)	Summer 2007	1,712,000	$	5.75	$7.38	$	10.50
Collars (3 way)	Winter 2007/2008	1,216,000	$	6.00	$9.00	$	14.80
Collars (3 way)	Summer 2008	1,712,000	$	5.00	$7.00	$	10.50

At September 30, 2006 and at December 31, 2005, the fair values of open derivative contracts were assets and liabilities of approximately $3.0 million and $11.5 million, respectively.

Sensitivity analyses of the incremental effects on pre-tax gain for the nine months ended September 30, 2006 of a hypothetical 10% and 25% change in natural gas prices for outstanding hedge contracts as of September 30, 2006 are provided in the following table:

	Incremental (increase) decrease in pre-tax gain assuming a hypothetical price increase and decrease of natural gas prices(1) (in thousands) 10%		25%	
Price increase	$	(2,256)	$	(5,832)
Price decrease	$	2,110	$	4,873

(1) We remain at risk for possible changes in the market value of these derivative contracts; however, any unfavorable increases would be partly offset by higher revenues due to higher sales prices for our gas. The favorable effect of this offset is not reflected in the sensitivity analyses.

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 CBM 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, and the timing and volume of initial and subsequent natural gas production. We estimate total capital expenditures in 2006 will be approximately $90 million with approximately 80% allocated to development projects, 12% to exploration projects, 4% to leasehold acquisitions and the remaining 4% for other items (primarily capitalized overhead and interest and administrative capital expenditures), representing an increase of approximately $30 million over our actual 2005 capital expenditures. The increase is primarily attributable to increased development expenditures at Pond Creek and Cahaba. Capital expenditures for the nine months ended September 30, 2006 and 2005 were $58.3 million and $49.4 million, respectively, and have been primarily concentrated at Pond Creek, Cahaba, and British Columbia.

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 $150 million. The borrowing base is subject to semi-annual redeterminations. The lenders also have the right to require one additional redetermination 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 Interbank 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.

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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 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. The next scheduled re-determination is to occur as of June 30, 2006 and will be completed by December 31, 2006. 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, 2006, $41 million was outstanding under our credit facility. Interest on the borrowings averaged 6.33% per annum. Borrowing availability at September 30, 2006 was $109 million. 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, 2006, a 1% change in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $410,000.

At September 30, 2006, 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.

Off-Balance Sheet Arrangements

We market all of our gas through Shamrock Energy, LLC (Shamrock) under a natural gas purchase contract that, effective March 2006 may be terminated by either party upon 90 days notice. The purchase contract calls for Shamrock to purchase gas from us from our properties covered by the purchase contract, including all of our major properties. Shamrock provides us with several related services, including nominations, gas control, gas balancing, transportation and exchange, market and transportation intelligence, and other advisory and agency services.

On June 14, 2006, we entered into an option agreement with Jon M. Gipson, the president of Shamrock, pursuant to which we have the right, from August 1, 2006 to January 31, 2007, to acquire all of the outstanding equity interests of Shamrock. In exchange for this option, we agreed (i) to extend our gas marketing agreement with Shamrock for a term ending no earlier than January 31, 2007, (ii) to advance, on or before August 1, 2006, $90,000 to Shamrock for working capital purposes during the option period, (iii) to provide any guarantees on behalf of Shamrock, up to an aggregate of $1,500,000, for transactions that Shamrock enters into during the option period that require such guarantees, and (iv) to advance up to an additional $50,000 to Shamrock as may be required to cover certain expenses of Shamrock prior to January 31, 2007, the date on which our option to purchase Shamrock expires. In July 2006, Mr. Gipson acquired all of the outstanding equity interest of Shamrocks from Optigas for $1.00. In August 2006, we advanced Shamrock $90,000 for working capital purposes, and we issued two guarantees, totaling $1,160,000, to Shamrock s customers in accordance with the option agreement. As of the date of this filing, the guarantees have not been called, and the advance is still outstanding. Although we are the primary beneficiary of

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this variable interest entity, the creditors of Shamrock do not have recourse against our general credit, and our losses are limited to our exposure under the guarantee and the $90,000 advance.

In the event that we exercise the Shamrock option, we will be obligated to provide Mr. Gipson an at-will employment position with us at an annual salary of not less than $130,000, and we will also pay Mr. Gipson an amount equal to 50% of the net profits generated by Shamrock from August 1, 2006 through the date that we elect to exercise the option, up to January 31, 2007. No additional consideration is due upon our exercise of the Shamrock option. In the event we do not exercise the option by January 31, 2007 and Mr. Gipson continues to operate Shamrock after the end of the option period, Shamrock will retain 100% of the net profits generated during the option period, all guarantees that we have entered into on behalf of Shamrock will terminate on January 31, 2007, and Shamrock will repay us all funds that we advanced to Shamrock in equal monthly payments, without interest, over an 18-month period. If we do not exercise the option by January 31, 2007 and Mr. Gipson elects not to continue to operate Shamrock, Mr. Gipson will wind up the affairs of Shamrock within 90 days after the end of the option period, and we will receive 100% of the net profits from Shamrock s operations during the wind-up period and the proceeds from the liquidation of Shamrock s assets, until we have been repaid all funds that we advanced to Shamrock and all guarantees that we entered into on behalf of Shamrock have been terminated and released.

In accordance with FIN 46(R), we consolidated Shamrock into our financial statements, effective August 1, 2006. Consolidation of Shamrock did not have a material impact on our results of operations for the three and nine months ended September 30, 2006. Other than the Shamrock customers that we have provided guarantees to on behalf of Shamrock, the remainder of Shamrock s customers have no recourse against us. Our losses are limited to the current advance of $90,000 and the amounts outstanding under the existing guarantee ($1,160,000). As of September 30, 2006, $3,209,419 of assets and $3,209,419 of liabilities have been included in our unaudited consolidated balance sheet as a result of applying FIN 46(R) to Shamrock, a variable interest entity.

Foreign Currency Exchange Rate Risk

We began exploratory operations in Canada in the fourth quarter of 2004 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 engaged in the exploration, development, and production of natural gas from coal seams (coalbed methane) in the U. S. and Canada. We operate in two segments, natural gas exploration, development and production, almost exclusively within the continental United States and British Columbia and gas marketing in the United States.

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 Liquidi and Capital Resources Foreign Currency Exchange Rate Risk above.

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, 2006 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

From time to time we are a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on our financial condition, results of operations or cash flows.

El Paso Overriding Royalty Interest Dispute

We filed a claim on June 9, 2004 against El Paso Production Company, CMV Joint Venture and CDX Minerals, LLC seeking a declaratory judgment of its rights under a joint operating agreement covering certain properties in White Oak Creek. We had previously entered into an agreement to sell its interest to CDX, subject to a preferential right to purchase held by El Paso, which El Paso subsequently exercised. A dispute arose as to whether the preferential right granted under the agreement applied to overriding royalty interests and other related interests. We have asserted that the preferential right to purchase does not include overriding royalty interests, and that we are entitled to retain all overriding royalty interests we possess under the agreement. The trial court rendered judgment in our favor, and El Paso has appealed the decision of the trial court. Oral argument was held on October 11, 2006 at the Dallas Court of Appeals. A decision from that court has not yet been entered. While we believe that we are entitled to retain these interests, a judgment against us would result in it being required to sell the overriding royalty interest to El Paso for a price of approximately $10.5 million; however, this amount would be reduced by any proceeds we have received from production since the effective date of the sale.

CNX Surface Use Dispute

We and Pocahontas Mining Limited Liability Company (PMC) filed a claim in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX Gas Company LLC (CNX) seeking a temporary and permanent injunction, as well as a declaration of our rights under a right-of-way agreement that we entered into with PMC, the surface owner. We are in the process of constructing a 12-mile pipeline, a portion of which traverses this right-of-way to connect with and transport our gas to the Jewell Ridge Pipeline. We have completed construction of the pipeline for the portion across the disputed right-of-way. CNX claimed that it has the exclusive right to transport gas across the acreage in question and that our right-of-way is invalid. CNX also gated certain access roads to the acreage and requested that we remove our contractor s equipment from the property. The Circuit Court of Buchanan County, Virginia conducted evidentiary hearings on June 15, 2006 and July 6, 2006. At the hearings the court ordered CNX to allow us and PMC access to the property over and across the existing roads and directed the parties to prepare a scheduling order setting forth the timelines for discovery and setting the trial date for this matter for November 15, 2006. The trial date has been reset for April 17 and 18, 2007. 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.

We believe that our right-of-way agreement is valid and enforceable and that we will prevail in the lawsuit; however, in the event we are unsuccessful in obtaining a favorable declaratory judgment, we may be required to construct an alternate pipeline at a cost in excess of $12 million, change the planned route of the pipeline we are currently constructing at a cost that could add more than $5 million to the cost of construction of the pipeline, pay CNX an access fee for any gas transported across the PMC property at a rate up to 3.5% of the gross proceeds from the sale of such gas, or seek other transportation alternatives through pipelines owned by third parties. We do not know what the cost of other transportation alternatives with third parties would be at this time, but we believe that such cost would be significantly in excess of the costs related to the construction and operation of our own pipeline. Any of these alternatives may result in our inability to deliver our gas from the Pond Creek field to market for an extended period of time. If we are unable to deliver its gas to market for a prolonged period of time, our financial

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position, results of operations and cash flow will be materially adversely affected.

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in the Risk Factors section of our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 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.

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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 13, 2006	By: /s/ William C. Rankin William C. Rankin, Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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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