Linn Energy, LLC
Form 10-Q
June 30, 2006

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

Form 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Quarterly Period Ended March 31, 2006
OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
for the transition period from __________ to __________
Commission File Number: 000-51719

LINN ENERGY, LLC
(Exact name of registrant as specified in its charter)

Delaware	**65-1177591**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

650 Washington Road
8th Floor
Pittsburgh, PA 15228
(Address of principal executive offices)
(412) 440-1400
(Registrant s telephone number, including area code)

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 þ No o

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. (Check one):

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

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

As of June 1, 2006, there were 27,832,500 units outstanding.

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Item 1. Financial Statements.

LINN ENERGY, LLC
CONSOLIDATED BALANCE SHEETS

	March 31, 2006 (Unaudited)	December 31, 2005
	(in thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 15,880	$ 11,041
Receivables:		
Natural gas and oil, net of allowance for doubtful accounts of $100,000 as of March 31, 2006 and December 31, 2005	9,387	17,103
Other	241	650
Fair value of interest rate swaps	273	202
Inventory	68	68
Current portion of natural gas derivatives	8,831	1,601
Prepaid expenses and other current assets	1,528	4,068
Total current assets	36,208	34,733
Natural gas and oil properties and related equipment	272,048	249,565
Less accumulated depreciation, depletion, and amortization	14,254	10,707
	257,794	238,858
Property and equipment, net	3,626	2,525
Other assets:		
Prepaid drilling costs	418	435
Long-term portion of natural gas derivatives	3,751	2,795
Operating bonds	197	198
	4,366	3,428
Total assets	$ 301,994	$ 279,544

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

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LINN ENERGY, LLC
CONSOLIDATED BALANCE SHEETS

	March 31, 2006	December 31, 2005
	(Unaudited)	
	(in thousands)	
Liabilities and Unitholders Capital (Deficit)		
Current liabilities:		
Current portion of long-term notes payable	$ 442	$ 113
Subordinated term loan		59,501
Accounts payable and accrued expenses	4,257	5,572
Current portion of natural gas derivatives	4,869	12,094
Revenue distribution	1,520	6,082
Accrued interest payable	958	1,448
Gas purchases payable	761	1,208
Other current liabilities	40	40
Total current liabilities	12,847	86,058
Long-term liabilities:		
Long-term portion of notes payable	1,476	695
Credit facility	157,279	206,119
Long-term portion of interest rate swaps	327	663
Asset retirement obligation	5,555	5,443
Long-term portion of natural gas derivatives	18,955	27,139
Other long-term liabilities	368	258
Total long-term liabilities	183,960	240,317
Total liabilities	196,807	326,375
Unitholders capital (deficit):		
27,812,500 Units issued and outstanding at March 31, 2006	146,065	16,024
Accumulated loss	(40,878)	(62,855)
	105,187	(46,831)
Total liabilities and unitholders capital (deficit)	$ 301,994	$ 279,544

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

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LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three months ended March 31, 2006	2005
	(in thousands)	
Revenues:		
Natural gas and oil sales	$ 16,375	$ 6,146
Realized gain (loss) on natural gas derivatives	3,323	(8,575)
Unrealized gain (loss) on natural gas derivatives	20,923	(6,580)
Natural gas marketing income	1,218	814
Other income	289	74
	42,128	(8,121)
Expenses:		
Operating expenses	2,994	1,817
Natural gas marketing expense	983	790
General and administrative expenses	9,470	478
Depreciation, depletion and amortization	3,700	1,181
	17,147	4,266
	24,981	(12,387)
Other income and (expenses):		
Interest income	146	
Interest and financing expense	(2,639)	20
Write-off of deferred financing fees and other losses	(392)	(32)
	(2,885)	(12)
Income (loss) before income taxes	22,096	(12,399)
Income tax (provision)	(119)	
Net income (loss)	$ 21,977	$ (12,399)
Net income (loss) per unit basic	$ 0.84	$ (.60)
Net income (loss) per unit diluted	$ 0.84	$ (.60)
Weighted average units outstanding basic	26,272,564	20,518,065
Weighted average units outstanding diluted	26,272,564	20,518,065

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

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LINN ENERGY, LLC
CONSOLIDATED STATEMENT OF UNITHOLDERS CAPITAL (DEFICIT)
For the Three Months Ended March 31, 2006
(Unaudited)

	Unitholders Capital	Accumulated Loss	Treasury Units (at Cost)	Total Unitholders Capital (Deficit)
		(in thousands)		
Balance as of December 31, 2005	$ 16,024	$ (62,855)		$ (46,831)
Sale of units, net of offering expense of $4,339	225,139		13,671	238,810
Redemption of member interests			(114,449)	(114,449)
Cancellation of member interests	(100,778)		100,778	
Unit-based compensation expense	5,680			5,680
Net income		21,977		21,977
Balance as of March 31, 2006	$ 146,065	$ (40,878)		$ 105,187

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

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LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three months ended March 31,	
	2006	2005
	(in thousands)	
Cash flow from operating activities:		
Net income (loss)	$ 21,977	$ (12,399)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	3,700	1,181
Amortization of deferred financing fees	190	45
Write-off of deferred financing fees and other losses	392	32
Accretion of asset retirement obligation	58	25
Unrealized (gain) loss on natural gas and interest rate derivatives	(21,330)	5,624
Unit-based compensation	5,680	
Changes in assets and liabilities:		
Decrease in accounts receivable	8,126	906
(Increase) decrease in prepaid expenses and other assets	(992)	11
(Decrease) in accounts payable and accrued expenses	(4,344)	(1,162)
(Decrease) in natural gas derivatives	(2,673)	(522)
(Decrease) in revenue distribution	(4,562)	(215)
Increase in asset retirement obligation	4	11
(Decrease) in accrued interest payable	(489)	(298)
Increase in other liabilities	110	
(Decrease) increase in gas purchases payable	(447)	22
Net cash provided by (used in) operating activities	5,400	(6,739)
Cash flow from investing activities:		
Acquisition and development of natural gas and oil properties	(21,784)	(1,899)
Purchases of property and equipment	(747)	(29)
Obligations related to drilling activities	3,024	
Proceeds from sale of assets	14	24
Decrease (increase) in operating bonds		(31)
Net cash used in investing activities	(19,493)	(1,935)
Cash flow from financing activities:		
Proceeds from sale of units	243,149	
Redemption of members units	(114,449)	
Proceeds from notes payable		5,000
Principal payments on notes payable	(60,056)	(14)
Principal payment on credit facility	(62,000)	
Proceeds from credit facility	13,000	3,000

Deferred offering costs		(807)		(265)
Deferred financing fees		95		(15)
Net cash provided by financing activities		18,932		7,706
Net increase (decrease) in cash		4,839		(968)
Cash and cash equivalents:				
Beginning		11,041		2,188
Ending	$	15,880	$	1,220
Supplemental disclosure of cash flow information:				
Cash payments for interest	$	3,336	$	1,189
Supplemental disclosure of non cash investing and financing activities:				
Increase in natural gas and oil properties and related asset retirement obligation due to acquisitions and new drilling	$	49	$	5
Acquisition of vehicles and equipment through the issuance of notes payable		1,172		

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

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

(1) Basis of Presentation

The consolidated financial statements at March 31, 2006 and for the three months ended March 31, 2006 and 2005 are unaudited, but in the opinion of management include all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles in the United States have been condensed or omitted under the Securities and Exchange Commission s rules and regulations. The results reported in these unaudited condensed consolidated financial statements should not necessarily be taken as indicative of results that may be expected for the entire year.

The financial information included herein should be read in conjunction with the financial statements and notes in our Annual Report on Form 10-K for the year ended December 31, 2005.

(2) Summary of Significant Accounting Policies

(a) Organization and Description of Business

Linn Energy, LLC (Linn or the Company) was reorganized as a limited liability company in April 2005 under the laws of the State of Delaware. The Company is an independent natural gas and oil company focused on the development and acquisition of properties in the Appalachian Basin, primarily in West Virginia, Pennsylvania, New York and Virginia. Linn s wholly owned subsidiaries include Linn Energy Holdings, LLC (Holdings), Linn Operating, Inc. (Operating), Penn West Pipeline, LLC (Penn West), and Mid Atlantic Well Service, Inc. (Mid Atlantic).

(b) Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The Company presents its financial statements in accordance with U.S. generally accepted accounting principles. All material inter-company transactions and balances have been eliminated upon consolidation.

(c) Cash Equivalents

For purposes of the statement of cash flows, the Company considers all highly liquid debt instruments with original maturities of three months or less to be cash equivalents.

(d) Natural Gas and Oil Properties

The Company accounts for natural gas and oil properties by the successful efforts method. Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold costs are transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

Depreciation and depletion of producing natural gas and oil properties is recorded based on units of production. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Statement of Financial Accounting Standards (SFAS) No. 19 requires that acquisition costs of proved properties be amortized on the basis of all proved reserves, developed and undeveloped, and that capitalized development costs (wells and related equipment and facilities) be amortized on the basis of proved developed reserves. The Company follows SFAS No. 143. Under SFAS 143, estimated asset retirement costs are recognized when the obligation is incurred, and are amortized over proved developed reserves using the units of production method. Asset retirement costs are estimated by the Company s engineers using existing regulatory requirements and anticipated future inflation rates.

Geological, geophysical and exploratory dry hole costs on natural gas and oil properties relating to unsuccessful exploratory wells are charged to expense as incurred.

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Upon sale or retirement of complete fields of depreciable or depleted property, the book value thereof, less proceeds or salvage value, is charged or credited to income. On sale or retirement of an individual well the proceeds are credited to accumulated depreciation and depletion.

Natural gas and oil properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. The Company assesses impairment of capitalized costs of proved natural gas and oil properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. No impairments were recorded during the first three months of 2006 or 2005.

Unproved properties that are individually insignificant are amortized. Unproved properties that are individually significant are assessed for impairment on a property-by-property basis. If considered impaired, costs are charged to expense when such impairment is deemed to have occurred.

(e) Natural Gas and Oil Reserve Quantities

The Company s estimate of proved reserves is based on the quantities of natural gas and oil that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Schlumberger Data and Consulting Services prepares a reserve and economic evaluation of all the Company s properties on a well-by-well basis annually.

Reserves and their relation to estimated future net cash flows impact the Company s depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The Company prepares its reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The independent engineering firm described above adheres to the same guidelines when preparing their reserve reports. The accuracy of the Company s reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates.

The Company s proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of natural gas, natural gas liquids and oil eventually recovered.

(f) Income Taxes

The Company is a limited liability company treated as a partnership for federal and state income tax purposes with all income tax liabilities and/or benefits of the Company being passed through to the unitholders. As such, no recognition of federal or state income taxes for the company and its subsidiaries that are organized as limited liability companies have been provided for in the accompanying financial statements except as described below.

Certain subsidiaries are subchapter C-corporations subject to corporate income taxes, which are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax liabilities of approximately $193,000 and $74,000 have been included in other long-term liabilities as of March 31, 2006 and December 31, 2005, respectively. Deferred tax benefits of $900,000 related to net operating losses and other carry-forwards are reflected net of a valuation allowance of the same amount since, as of March 31, 2006, the subsidiaries generating that benefit are unlikely to generate adequate on-going taxable income to realize those benefits.

(g) Derivative Instruments and Hedging Activities

The Company periodically uses derivative financial instruments to achieve a more predictable cash flow from its natural gas production by reducing its exposure to price fluctuations. As of March 31, 2006, these transactions were in the form of swaps and puts. Additionally, the Company uses derivative financial instruments in the form of interest rate swaps to mitigate its interest rate exposure. The Company accounts for its derivatives at fair value as an asset or liability and the change in the fair value of derivatives is included in income.

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(h) *Earnings per unit*

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. During 2006 for the period prior to the Offering, equivalent units were calculated by adjusting pre-Offering members membership interests by the exchange ratio to reflect the exchange of pre-Offering membership interests for post-Offering units and cash immediately prior to completion of the Offering (see Note 3). Diluted earnings per unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. The Company uses the treasury stock method to determine the dilutive effect. For the quarter ended March 31, 2006, unvested units granted but not issued to the CEO and all unit options outstanding were excluded in the computation of diluted EPS, because to do so would have been antidilutive for the period.

(i) *Use of Estimates*

Management of the Company has made a number of estimates and assumptions relating to the reporting of assets and liabilities and revenues and expenses and the disclosure of contingent assets and liabilities to prepare these financial statements in conformity with U.S. generally accepted accounting principles. Actual results could differ from those estimates. The estimates that are particularly significant to the financial statements include estimates of natural gas and oil reserves, future cash flows from natural gas and oil properties, and depreciation, depletion and amortization, asset retirement obligations and the fair value of derivatives.

(j) *Revenue Recognition*

Sales of natural gas and oil are recognized when natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured, and the sales price is fixed or determinable. Natural gas is sold by the Company on a monthly basis. Virtually all of the Company s contracts pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas, and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, the Company s revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. The Company believes that the pricing provisions of its natural gas contracts are customary in the industry.

Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess of the Company s share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. The Company did not have any significant gas imbalance positions at March 31, 2006 or December 31, 2005.

Natural gas marketing is recorded on the gross accounting method because Penn West, the Company s marketing subsidiary, takes title to the natural gas it purchases from the various producers and bears the risks and enjoys the benefits of that ownership. Natural gas marketing revenues totaled $1,218,000 and $814,000 and natural gas marketing expenses were $983,000 and $790,000 for the three months ended March 31, 2006 and 2005, respectively.

The Company currently uses the Net-Back method of accounting for transportation arrangements of its natural gas sales. The Company sells natural gas at the wellhead and collects a price and recognizes revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by its customers and reflected in the wellhead price.

The Company is paid a monthly operating fee for each well it operates for outside owners. The fee covers monthly operating and accounting costs, insurance and other recurring costs. As the operating fee is a reimbursement for costs incurred on behalf of third parties, the fee has been netted against general and administrative expense. For the three months ended March 31, 2006 and 2005 the operating fees netted against general and administrative expense were $284,000 and $287,000, respectively.

(k) Unit-Based Compensation

The Company accounts for unit-based compensation pursuant to SFAS No. 123(R) *Share-Based Payment.* SFAS No. 123(R), which requires an entity to recognize at the grant date the fair value of unit options and other equity-based compensation issued to employees in the income statement. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service periods in the Company s consolidated income statement. Compensation expense attributable to granted awards are recognized using the straight-line method.

The Company utilizes a Black-Scholes option pricing model to measure the fair value of unit options granted to employees. The Company s determination of fair value of unit-based payment awards on the date of grant using the model is affected by the Company s unit price as well as assumptions regarding a number of highly complex and subjective variables. These variables include, but are not limited to, the Company s expected unit price volatility over the term of the awards, and actual and projected employee unit option exercise behaviors. In addition, forfeitures are required to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. Although the fair value of employee unit options is determined in accordance with SFAS No. 123R and SAB 107 using a Black-Scholes option-pricing model, that value may not be indicative of the fair value observed in a willing buyer/willing seller market transaction. The Company is responsible for determining the assumptions used in estimating the fair value of its unit-based payment awards. The Company recorded $5,680,000 of unit-based compensation expense for the three months ended March 31, 2006. As of March 31, 2005 and December 31, 2005, there were no outstanding unit-based awards.

(l) Recently Issued Accounting Standards

As of January 1, 2006, the Company adopted SFAS No. 154 Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and SFAS No. 3 (SFAS No. 154). SFAS No. 154 requires retrospective application of voluntary changes in accounting principles, unless it is impracticable. The implementation of this standard did not have a material impact on the consolidated financial statements.

(3) Initial Public Offering

During the three months ended March 31, 2006, the Company completed its initial public offering (IPO) of 12,450,000 units representing limited liability interests in the Company at $21.00 per unit, for net proceeds, after underwriting discounts and other offering costs, of $243.1 million, of which $122.0 million was used to reduce indebtedness under the Company s revolving credit facility and repay, in full, the subordinated term loan, approximately $114.4 million was used to redeem a portion of the membership interests in the Company and units held by certain affiliated and non-affiliated holders, approximately $4.3 million was used to pay offering expenses and approximately $2.0 million was used to pay bonuses to certain executive officers of the Company.

Subsequent to March 31, 2006, the Company s Board of Directors declared distributions of $0.32 per unit with respect to the first quarter of 2006 pro-rated for the period from the closing of the offering on January 19, 2006 to March 31, 2006. As a result, the Company paid aggregate distributions of approximately $8.9 million on May 15, 2006.

(4) Natural Gas and Oil Properties:

	March 31, 2006	December 31, 2005
Unproved Properties	$ 6,181,000	$ 4,562,000
Proved Developed Properties:		
Acquisition, equipment and drilling	260,267,000	239,423,000
Pipelines	5,600,000	5,580,000
	272,048,000	249,565,000
Less accumulated depreciation, depletion and amortization	(14,254,000)	(10,707,000)
	$ 257,794,000	$ 238,858,000

(5) Debt

Credit Facility

On April 7, 2006, the Company replaced its prior credit agreement and entered into a new $400.0 million Amended and Restated Credit Agreement (the Credit Agreement) with BNP Paribas as administrative agent. The Credit Agreement matures on April 13, 2009. The amount available for borrowing at any one time is limited to the borrowing base, which as a result of this new arrangement increased from $225.0 million to $235.0 million. The borrowing base further increased to $265.0 million in June 2006. The borrowing base will be redetermined semi-annually by the lenders in their sole discretion, based on, among other things, reserve reports as prepared by reserve engineers taking into account the natural gas and oil prices at such time. Our obligations under the Credit Agreement are secured by mortgages on our natural gas and oil properties as well as a pledge of all ownership interests in our operating subsidiaries. We are required to maintain the mortgages on properties representing at least 80% of our natural gas and oil properties. Additionally, the obligations under the Credit Agreement are guaranteed by all of our operating subsidiaries and may be guaranteed by any future subsidiaries.

Borrowings under the Credit Agreement are available for acquisition and development of natural gas and oil properties, working capital, and general corporate purposes. At our election, interest is determined by reference to the London interbank offered rate (LIBOR) plus an applicable margin between 1.00% and 1.75% per annum; or a domestic bank rate plus an applicable margin between 0.00% and 0.25% per annum. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

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The Credit Agreement contains various covenants that limit the Company s ability to incur additional indebtedness, make acquisitions or certain capital expenditures; make distributions other than from available cash; merge or consolidate; and engage in certain asset dispositions. The Credit Agreement also contains covenants that, among other things, require us to maintain specified financial ratios. The Company obtained a waiver through June 30, 2006 from the covenant under its credit facility regarding the timely provision of quarterly financial statements to the administrative agent under the facility. The Company is in compliance with all financial and other covenants of its credit facility.

As of March 31, 2006 and December 31, 2005, the credit facility consisted of the following:

	March, 31 2006	**December, 31, 2005**
Outstanding balance	$ 158,000,000	$ 207,000,000
Less deferred financing fees, net of amortization of $226,000 and $160,000	(721,000)	(881,000)
	$ 157,279,000	$ 206,119,000

Accrued interest was $958,000 and $1,052,898 at March 31, 2006 and December 31, 2005, respectively.

As of June 21, 2006 we had outstanding indebtedness of $193.6 million under the credit facility and additional borrowing ability of $71.4 million.

Subordinated Term Loan

On October 27, 2005, the Company entered into a facility for a $60 million second lien senior subordinated term loan (the subordinated term loan) with Royal Bank of Canada and Societe Generale. The borrowings under the subordinated term loan were used to fund a portion of the purchase price for the acquisition of natural gas and oil properties from Exploration Partners. The outstanding balance was paid in full in January 2006 with proceeds from our initial public offering.

(6) Long-term Notes Payable

The Company has the following long-term notes payable outstanding:

	March 31, 2006	**December 31, 2005**
Note payable to a bank with an interest rate of 6.14%, payable in monthly installments of $2,918, including interest, through September 2024. The note is secured by an office building.	$ 384,000	$ 387,000
Various notes for the purchase of vehicles and equipment, payable in monthly installments totaling $41,315 and $10,806 as of March 31, 2006 and December 31, 2005, respectively, including interest. The interest rates range from 0-8.74%. The notes are secured by the vehicles purchased and expire at various dates from 2008 through 2011.	1,534,000	421,000
	1,918,000	808,000
Less current portion	442,000	113,000
	$ 1,476,000	$ 695,000

As of March 31, 2006, maturities on the aforementioned long-term notes payable were as follows:

March 31:	
2006	$ 442,000
2007	439,000
2008	374,000
2009	200,000
2010	146,000
Thereafter	317,000
	$ 1,918,000

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(7) Business and Credit Concentrations

Cash

The Company maintains its cash in bank deposit accounts, which, at times, may exceed federally insured amounts. The Company has not experienced any losses in such accounts. The Company believes it is not exposed to any significant credit risk on its cash.

Revenue and Trade Receivables

The Company has a concentration of customers who are engaged in natural gas and oil production within the Appalachian region. This concentration of customers may impact the Company s overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. The Company performs ongoing credit evaluations of its customers and generally does not require collateral.

The Company s largest customers are natural gas producers and suppliers located within the Appalachian region. For the three months ended March 31, 2006, the Company s two largest customers represented 70% and 10% of the Company s sales. The Company s four largest customers represented approximately 27%, 21%, 14%, and 10% of the Company s sales for the three months ended March 31, 2005.

Trade accounts receivable from natural gas sales from two customers accounted for more than 10% of the Company s trade accounts receivable. As of March 31, 2006, trade accounts receivable from these customers represented approximately 70%, and 11% of the Company s receivables. Trade accounts receivable for the four largest customers represented approximately 27%, 23%, 14% and 10% of the Company s receivables as of March 31, 2005.

(8) Unit-Based Compensation

The Linn Energy, LLC Long-Term Incentive Plan (the Plan) permits the granting of unit grants, unit options, restricted units, phantom units and unit appreciation rights under the terms of the Plan. The Plan limits the number of units that may be delivered pursuant to awards to 3.9 million units, provided that no more than 500,000 of such units (as adjusted) may be issued as restricted units. The plan is administered by the compensation committee of our Board of Directors.

Our Board of Directors and the compensation committee of the Board have the right to alter or amend the Plan or any part of the Plan from time to time, including increasing the number of units that may be granted, subject to unitholder approval as required by the exchange upon which the units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the benefits to the participant without the consent of the participant.

Upon exercise or vesting of an award of, or settled in, units the Company will issue new units, acquire units on the open market or directly from any person or use any combination of the foregoing, in the compensation committee s discretion. If we issue new units upon exercise or vesting of an award of, or settled in, units, the total number of units outstanding will increase. The plan provides for following types of awards:

Unit Grants. A unit grant is a unit that vests immediately upon issuance.

Unit Options. A unit option is a right to purchase a unit at a specified price at terms determined by the committee. Unit options will have an exercise price that will not be less than the fair market value of the units on the date of grant, and in general, will become exercisable over a vesting period but may accelerate upon the achievement of specified financial objectives, or upon a change in control of the Company. If a grantee s employment or relationship terminates for any reason, the grantee s unvested unit options will be automatically forfeited unless the option agreement or the compensation committee provides otherwise.

Restricted Units. A restricted unit is a unit that vests over a period of time and that during such time is subject to forfeiture, and may contain such terms as the compensation committee shall determine, including the period over which restricted units (and distributions related to such units) will vest. The Company intends the restricted units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our units. Therefore, plan participants will not pay any consideration for the units they receive. If a grantee s employment, consulting relationship or membership on the Board of Directors terminates for any reason, the grantee s restricted units will be automatically forfeited unless the compensation committee or the terms of the award agreement provide otherwise.

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Although not initially expected to be granted, the plan also authorizes Phantom Units and Unit Appreciation Rights, which may be settled in units, cash or a combination thereof. Such grants will contain terms as determined by the compensation committee, including the period or terms over which phantom units will vest. If a grantee s employment or relationship terminates for any reason, the grantee s phantom units or unit appreciation rights will be automatically forfeited unless, and to the extent, the compensation committee or the terms of the award agreement provide otherwise. While phantom units require no payment from the grantee, unit appreciation rights will have an exercise price that will not be less than the fair market value of the units on the date of grant.

Accounting for unit-based compensation. SFAS No. 123R provides specific guidance on income tax accounting and clarifies how SFAS No. 109, *Accounting for Income Taxes*, should be applied to unit-based compensation. For example, the expense for types of option grants is only deductible for tax purposes at the time that the taxable event takes place. SFAS No. 123R does not allow companies to predict when these taxable events will take place. Furthermore, it requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow, rather than as an operating cash flow as required under SFAS No. 123. This requirement will reduce net operating cash flows and increase net financing cash flows in periods. These future amounts cannot be estimated, because they depend on, among other things, when employees exercise unit options.

For the three months ended March 31, 2006, we recorded unit-based compensation of $5,680,000 as a charge against income before income taxes and is included in general and administrative expense. No related income tax benefit was recognized due to Section 162(m) deductibility limits and recognition of a valuation allowance for resulting net operating losses.

Restricted/Unrestricted Units

The fair value of the awards issued is determined based on the fair market value of the units on the date of grant. This value is amortized over the vesting period, which varied between one to two years from the date of grant for certain officers. A summary of the status of the non-vested units as of March 31, 2006, and changes during the three months ended March 31, 2006, is presented below:

	Number of Non-vested Units	**Weighted Average Grant-Date Fair Value**
Non-vested units as of December 31, 2005		$
Granted	854,690	21.00
Vested		
Forfeited		
Non-vested units as of March 31, 2006	854,690	$ 21.00

As of March 31, 2006, there was $14.7 million of total unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of 1.3 years.

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Securities Authorized for Issuance Under Equity Compensation Plan. As of March 31, 2006, the Company had 3.9 million units issuable pursuant to outstanding award agreements or reserved for issuance under the Company s Long-Term Incentive Plan.

Changes in Unit Options and Unit Options Outstanding.

The following table provides information related to unit option activity for the three months ended March 31, 2006:

	Number of Units Underlying Options	Weighted Average Exercise Price Per Unit	Weighted Average Grant Date Fair Value	Weighted Average Contractual Life in Years
Outstanding at December 31, 2005		$	$	
Granted	456,084	20.74	3.22	10.00
Exercised				
Forfeited				
Vested				
Outstanding at March 31, 2006	456,084	$ 20.74	$ 3.22	10.00
Exercisable at March 31, 2006	30,000	$ 20.18	$ 2.80	10.00

As of March 31, 2006, there was $0.7 million of total unrecognized compensation cost related to non-vested unit options. The cost is expected to be recognized over a weighted average period of 3 years. In addition, the exercisable options at March 31, 2006 have an aggregate intrinsic value of $6,600 and all outstanding options have an aggregate intrinsic value of $36,000. No options expired during the period.

Subsequent to March 31, 2006, the Company granted an aggregate 75,000 options which are subject to both performance and service requirements and 20,000 restricted units to an executive officer.

The fair value of unit-based compensation was estimated on the date of grant using a Black-Scholes pricing model based on assumptions noted in the following table. The Company s employee unit options have various restrictions including vesting provisions and restrictions on transfers and hedging, among others, and are often exercised prior to their contractual maturity. Expected volatilities used in the estimation of fair value have been determined using all available volatility data for the Company as well as an average of volatility computations of other identified peer companies in the oil and gas industry. The Company uses historical data to estimate unit option exercises, expected term and employee departure behavior used in the Black-Scholes pricing model. All employees granted awards have been determined to have similar behaviors for purposes of determining the expected term used to estimate fair value. The risk-free rate for periods within the contractual term of the unit option is based on the U.S. Treasury yield curve in effect at the time of grant. The fair values of the grants were based upon the following assumptions.

Expected volatility	29.70%
Expected dividends (weighted average 7.5%)	7.2%-7.9%
Expected term (in years)	5.00
Risk free rate	4.31%-4.75%
Expected forfeiture rate	23.10%

(9) Property and Equipment

Property and equipment consists of the following:

	March 31, 2006	December 31, 2005
Land	$ 308,000	$ 203,000
Buildings and leasehold improvements	1,001,000	608,000
Vehicles	1,842,000	1,317,000
Furniture and equipment	1,099,000	888,000
	4,250,000	3,016,000
Accumulated depreciation	624,000	491,000
	$3,626,000	$ 2,525,000

Depreciation expense for the three months ended March 31, 2006 and 2005 was approximately $153,000 and $53,000, respectively.

(10) Commitments and Contingencies

The Company would be exposed to natural gas price fluctuations on underlying sale contracts should the counterparties to the Company s derivative instruments or the counterparties to the Company s natural gas marketing contracts not perform. Such nonperformance is not anticipated. There were no counterparty default losses during the three months ended March 31, 2006 or 2005.

From time to time the Company is a party to various legal proceedings in the ordinary course of business. The Company is not currently a party to any litigation that it believes would have a materially adverse effect on the Company s business, financial condition, results of operations or liquidity.

(11) Natural Gas Derivatives

The Company sells natural gas in the normal course of its business and utilizes derivative instruments to minimize the variability in forecasted cash flows due to price movements in natural gas. The Company enters into derivative instruments such as swap contracts and put options to hedge a portion of its forecasted natural gas sales.

The following table summarizes open positions as of March 31, 2006 and represents our derivatives in place through December 31, 2009. Settled derivatives on production for the three months ended March 31, 2006 included a volume of 2,019 MMMBtu at an average price of $9.23. Currently, we use fixed price swaps and puts to manage commodity prices. These transactions are settled based upon the NYMEX price of natural gas at Henry Hub on the final trading day of the month, and settlement occurs on the 3rd day of the production month.

	Year 2006	Year 2007	Year 2008	Year 2009
Fixed Price Swaps:				
Hedged Volume (MMMBtu)	5,573	7,168	6,904	5,125
Average Price ($/MMBtu)	$ 9.25	$ 8.64	$ 7.89	$ 7.25
Puts:				
Hedged Volume (MMMBtu)	550	730		
Average Price ($/MMBtu)	$ 8.83	$ 8.24	$	$
Total:				
Hedged Volume (MMMBtu)	6,123	7,898	6,904	5,125
Average Price ($/MMBtu)	$ 9.21	$ 8.60	$ 7.89	$ 7.25

The natural gas derivatives are not designated as hedges and, accordingly, the changes in fair value are recorded in current period earnings.

	March 31, 2006	December 31, 2005
Outstanding notional amounts of hedges (MMMBtu)	26,050	28,069
Maximum number of months hedges outstanding	45	48

By using derivative instruments to hedge exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company minimizes the credit risk in derivative instruments by entering into transactions with high-quality counterparties.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

Overview

We are an independent natural gas and oil company focused on the development and acquisition of properties in the Appalachian Basin, primarily in West Virginia, Pennsylvania, New York and Virginia. Our goal is to provide stability and growth in distributions to our unitholders through a combination of continued successful drilling and acquisitions. Our company was formed in March 2003. In 2006, we completed our initial public offering of 12,450,000 units at a price of $21.00 per unit, for proceeds after underwriting discounts of approximately $243.1 million, of which $122.0 million was used to reduce indebtedness under the Company s revolving credit facility and repay, in full, the subordinated term loan, approximately $114.4 million was used to redeem a portion of the membership interests in the Company and units held by certain affiliated and non-affiliated holders, approximately $4.3 million was used to pay offering expenses and approximately $2.0 million was used to pay bonuses to certain executive officers of the Company.

During the second quarter of 2006, we closed three acquisitions of natural gas and oil properties in West Virginia, including 207 producing wells, and an acquisition of a natural gas gathering pipeline system in western Pennsylvania by its Penn West subsidiary for an aggregate contract purchase price of $30.0 million, subject to customary closing

adjustments. The acquired properties, all located in West Virginia, add 207 producing wells.
In addition, from inception through December 31, 2005, we completed nine acquisitions of natural gas properties and related gathering and pipeline assets for an aggregate purchase price of $201.5 million, with total proved reserves of 160.1 Bcfe, or an acquisition cost of $1.26 per Mcfe.

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Date	Seller	Gross Wells	Location	Purchase Price (in millions)
May 2003	Emax Oil Company	34	West Virginia	$ 3.2
Aug 2003	Lenape Resources, Inc.	61	New York	2.2
Sep 2003	Cabot Oil & Gas Corporation	50	Pennsylvania	15.8
Oct 2003	Waco Oil & Gas Company	353	West Virginia and Virginia	31.5
May 2004	Mountain V Oil & Gas, Inc.	251	Pennsylvania	12.5
Sep 2004	Pentex Energy, Inc.	447	Pennsylvania	15.1
Apr 2005	Columbia Natural Resources, LLC	38	West Virginia and Virginia	4.4
Aug 2005	GasSearch Corporation	130	West Virginia	5.4
Oct 2005	Exploration Partners, LLC	550	West Virginia and Virginia	111.4
	Total	1,914		$ 201.5

Because of our rapid growth through acquisitions and development of our properties, our historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results.

Our acquisitions were financed with a combination of private equity, proceeds from bank borrowings and cash flow from operations. Our activities are focused on evaluating and developing our asset base, increasing our acreage positions and evaluating potential acquisitions.

Our revenue, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Natural gas and oil prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for natural gas or oil could materially and adversely affect our financial position, our results of operations, the quantities of natural gas and oil reserves that we can economically produce and our access to capital.

We utilize the successful efforts method of accounting for our natural gas and oil properties. Leasehold costs are capitalized when incurred. Unproved properties that are individually insignificant are amortized. Unproved properties that are individually significant are assessed for impairment on a property-by-property basis. If considered impaired, costs are charged to expense when such impairments are deemed to have occurred. Geological and geophysical expenses and delay rentals are charged to expense as incurred. Drilling costs are typically capitalized, but charged to expense if an exploratory well is determined to be unsuccessful.

Higher natural gas and oil prices have led to higher demand for drilling rigs, operating personnel and field supplies and services and have caused increases in the costs of those goods and services. To date, the higher sales prices have more than offset the higher drilling and operating costs. Given the inherent volatility of natural gas prices, which are influenced by many factors beyond our control, we plan our activities and budget based on conservative sales price assumptions, which generally are lower than the average sales prices received. We focus our efforts on increasing natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future cash flow from operations is dependent on our ability to manage our overall cost structure.

We face the challenge of natural production declines. As initial reservoir pressures are depleted, natural gas production from a given well decreases. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on costs to add reserves through drilling and acquisitions as well as the costs necessary to produce such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals.

Our Operations

Our revenues are highly sensitive to changes in natural gas prices and levels of production. As set forth in Cash Flow from Operations below, we have hedged a significant portion of our expected production using natural gas derivatives, which allows us to mitigate, but not eliminate, natural gas price risk. Our expected increase in levels of production as a result of the anticipated drilling of 153 wells during 2006 is dependent on our ability to quickly and efficiently bring the newly drilled wells online. Any delays in drilling, completion or connection to gathering lines of our new wells will negatively impact the rate of increase in our production, which may have an adverse effect on our revenues and as a result, cash available for distribution. We continuously conduct financial sensitivity analyses to assess the effect of changes in pricing and production. These analyses allow us to determine how changes in natural gas prices will affect the ability to drill additional wells and to meet future financial obligations. Further, the financial analyses allow us to monitor any impact such changes in natural gas prices may have on the value of our proved reserves and their impact, if any, on any redetermination of the borrowing base under our credit facility.

Production and Operating Costs Reporting

We strive to increase our production levels to maximize our revenue and cash available for distribution. Additionally, we continuously monitor our operations to ensure that we are incurring operating costs at the lowest possible level. Accordingly, we continuously monitor our production and operating costs per well to determine if any wells should be shut in or sold.

Land and Lease Tracking System

As a significant amount of our growth is dependent on drilling new wells, we continuously monitor our lease agreements and our drilling locations to avoid delays. Our monitoring system matches our lease agreements to existing wells and sites for future development allowing management to make real time decisions on which acreage to develop and at what point in time. We continually seek to acquire new lease positions to increase potential drilling locations.

Results of Operations

The following table sets forth selected financial and operating data for the periods indicated.

	For the Three Months Ended March 31,	
	2006	2005
	(in thousands, except for per unit data) (Unaudited)	
Revenues:		
Natural gas and oil sales	$ 16,375	$ 6,146
Realized gain (loss) on natural gas derivatives	3,323	(8,575)
Unrealized gain (loss) on natural gas derivatives	20,923	(6,580)
Natural gas marketing income	1,218	814
Other income	289	74
Total revenue	42,128	(8,121)
Expenses:		
Operating expenses	$ 2,994	$ 1,817
Natural gas marketing expense	983	790
General and administrative expenses	9,470	478
Depreciation, depletion and amortization	3,700	1,181
Total expenses	17,147	4,266
Other Income and (Expenses):		
Interest and financing expense	$ (2,639)	$ 20
Net Production:		
Total production (MMcfe)	1,836	972
Average daily production (Mcfe/d)	20,400	10,800
Average Sales Prices:		
Weighted average realized natural gas price (Mcf)	$ 9.74	$ 5.84
Weighted average realized price (Mcfe)	9.72	5.85
Average Unit Costs per Mcfe (Non-GAAP):		
Operating expenses	$ 1.63	$ 1.87
General and administrative expenses (1)	0.97	0.49

Depreciation, depletion and amortization	2.02	1.22

(1) This is a non-GAAP performance measure used by our management and is a quantitative measure used in the oil and gas industry. The measure for the three months ended March 31, 2006 excludes approximately $2.0 million of bonuses paid and $5.7 million of unit- based compensation awarded to certain executive officers in connection with our IPO. General and administrative expenses per Mcfe including these amounts were $5.16 and $.49 for the three months ended March 31, 2006 and 2005, respectively.

Three Months Ended March 31, 2006 Compared to the Three Months Ended March 31, 2005

Revenue

Natural gas and oil sales, before realized and unrealized gains and losses on natural gas derivatives, increased to approximately $16.4 million from $6.1 million during the three months ended March 31, 2006 as compared to the three months ended March 31, 2005. The key revenue measurements were as follows:

	For the Three Months Ended March 31, 2006	For the Three Months Ended March 31, 2005	Percentage Increase (Decrease)
Net Production:			
Total production (MMcfe)	1,836	972	89%
Average daily production (Mcfe/d)	20,400	10,800	89%
Average Sales Prices:			
Weighted average realized natural gas price (Mcf)	$ 9.74	$ 5.84	67%
Weighted average realized price (Mcfe)	9.72	5.85	66%

The increase in natural gas and oil revenue was attributable primarily to the increase in production to 1,836 MMcfe during the three months ended March 31, 2006 from 972 MMcfe during the period ended March 31, 2005, the three acquisitions completed in 2005, and the drilling of 29 wells during the three months ended March 31, 2006 and 110 wells in 2005. In addition to the increase in production, the average natural gas sales price increased during the three months ended March 31, 2006 as compared to the three months ended March 31, 2005.

Hedging Activities

During the three months ended March 31, 2006, we hedged 100% of our natural gas production, which resulted in revenues that were $3.3 million greater than we would have achieved at unhedged prices. During the three months ended March 31, 2005, we hedged approximately 89% of our natural gas production, which resulted in revenues that were $0.6 million less than we would have achieved at unhedged prices. During the three months ended March 31, 2005, we cancelled (before their original settlement date) a portion of out-of-the- money natural gas derivatives and realized a loss of $8.0 million. We subsequently hedged similar volumes at higher prices. Unrealized gain on hedges in the amount of $21.0 million for the three months ended March 31, 2006 and unrealized loss on hedges in the amount of $6.6 million for the three months ended March 31, 2005 were also recorded.

Expenses

Operating expenses consist of lease operating expenses, labor, field office rent, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, severance and ad valorem taxes and other customary charges. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. We assess our operating expenses by monitoring the expenses in relation to the amount of production and the number of wells operated. Operating expenses increased to $3.0 million for the three months ended March 31, 2006 from $1.8 million for the three months ended March 31, 2005, due to the increase in the number of wells as a result of the three acquisitions completed in 2005 and the drilling of 29 wells during the three months ended March 31, 2006 and 110 wells in 2005. Operating expenses per Mcfe of production were as follows:

	For the Three Months Ended March 31, 2006	For the Three Months Ended March 31, 2005	Percentage Increase (Decrease)
Operating expenses per Mcfe	$ 1.63	$ 1.87	(13)%

General and administrative expenses include the costs of our employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. We monitor general and administrative expenses in relation to the amount of production and the number of wells operated. General and administrative expenses increased to $9.5 million from $0.5 million during the three months ended March 31, 2006 as compared to the three months ended March 31, 2005. During the three months ended March 31, 2006 and 2005, the Company capitalized approximately $0.3 million and $18,000, respectively, of internal costs related to drilling. Additionally, general and administrative expenses are presented net of approximately $0.3 million during each of the three month periods ended March 31, 2006 and 2005, respectively, which represents operating expense reimbursements from other working interest owners. In 2006, we recognized expense of approximately $2.0 million for bonuses paid to executives in connection with our IPO and $5.7 million for unit-based compensation related to restricted units issued in connection with the IPO and unit options issued for performance. The increase in general and administrative expenses was also due to our rapidly growing operations and increasing our staffing level to manage the additional wells acquired and drilled in 2006 and 2005, as well as to perform the functions associated with being a public company. General and administrative expenses per Mcfe of production were as follows:

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	For the Three Months Ended March 31, 2006	For the Three Months Ended March 31, 2005	Percentage Increase (Decrease)
General and administrative expenses per Mcfe	$ 0.97(1)	$ 0.49	98%

(1) See note (1) on page 18.

Depreciation, depletion and amortization increased to $3.7 million for the three months ended March 31, 2006 from $1.2 million for the three months ended March 31, 2005, due to the increase in the number of wells as a result of the three acquisitions completed in 2005 and the drilling of 29 wells during the three months ended March 31, 2006 and 110 wells in 2005.

Interest and financing income (expense) was $(2.6) million for the three months ended March 31, 2006 compared to $20,000 for the three months ended March 31, 2005. Our interest rate swaps were not specifically designated as hedges under SFAS No. 133, even though they reduce our exposure to changes in interest rates. Therefore, the mark to market of these instruments was recorded as a $0.4 million gain and a $1.0 million gain in our current earnings for the three months ended March 31, 2006 and 2005, respectively. Further, these amounts represent non-cash charges. Cash payments for interest expense increased to $3.3 million for the three months ended March 31, 2006 from $1.2 million for the three months ended March 31, 2005, primarily due to increased debt levels associated with the three acquisitions completed in 2005 and the drilling of 29 wells during the three months ended March 31, 2006 and 110 wells in 2005.

Income tax expense was approximately $119,000 for the three months ended March 31, 2006 compared to $0 for the three months ended March 31, 2005. Because we were structured as a limited liability company through May 31, 2005, no tax provision was recorded because all of our taxable income or loss was included in the income tax returns of the members. On June 1, 2005, Linn Operating, LLC (predecessor to Linn Operating, Inc.) converted to subchapter C-corporation status and on November 1, 2005 Mid Atlantic Well Service, Inc., one of our subsidiaries, commenced operations. Income tax expense relates to the income attributable to those entities. Deferred tax benefits arising from net operating losses have been offset by an increase in the valuation allowance.

Liquidity and Capital Resources

Sales and Issuances of Securities. In the first quarter of 2006, we completed our initial public offering of an aggregate of 12,450,000 units representing limited liability company interests (consisting of 11,750,000 units purchased by the underwriters on January 19, 2006 and 700,000 units purchased by the underwriters on February 15, 2006 pursuant to their option to purchase additional units) at an initial public offering price of $21.00 per unit in a firm commitment underwritten initial public offering pursuant to an S-1 Registration Statement (File No. 333-125501) declared effective by the Securities and Exchange Commission on January 12, 2006. RBC Capital Markets Corporation and Lehman Brothers Inc. acted as joint lead-managing underwriters of the offering.

The aggregate initial public offering price for the units issued in our initial public offering was approximately $261.4 million. Net proceeds to the Company (after underwriting discounts of approximately $18.3 million and estimated offering expenses of approximately $4.3 million) were approximately $238.8 million, of which $122.0 million was used to reduce the Company s then-existing indebtedness, an aggregate of $111.6 million was used to redeem a portion of the limited liability company membership interests and units held by certain affiliates, and an aggregate of $2.8 million was used to redeem a portion of the limited liability company interests and units held by certain non-affiliates of the Company.

Subsequent to March 31, 2006, the Company s Board of Directors declared distributions of $0.32 per unit with respect to the first quarter of 2006 pro-rated for the period from the closing of the offering on January 19, 2006 to March 31, 2006. As a result, the Company paid aggregate distributions of approximately $8.9 million on May 15, 2006. Management currently anticipates that it will recommend to the Board of Directors an increase in the annualized cash distribution of $0.12 per unit, or a 7.5% increase, to an annual rate of $1.72 per unit from the current annual rate of $1.60 per unit beginning with the cash distribution expected to be paid on or about November 14, 2006 with respect to the third fiscal quarter.

Credit Facility. On April 7, 2006, we entered into a new $400.0 million Amended and Restated Credit Agreement (the Credit Agreement) with BNP Paribas, as administrative agent, Royal Bank of Canada and Societe Generale, as syndication agents, Bank of America, N.A. and Comerica Bank, as documentation agents, and Bank of Scotland, Fortis Capital Corp. and Lehman commercial Paper Inc. The Credit Agreement matures on April 13, 2009. The amount available for borrowing at any one time is limited to the borrowing base, which as a result of this new arrangement increased from $225.0 million to $235.0 million. The borrowing base further increased to $265.0 million in June 2006. The borrowing base will be redetermined semi-annually by the lenders in their sole discretion, based on, among other things, reserve reports as prepared by reserve engineers taking into account the natural gas and oil prices at such time. Our obligations under the Credit Agreement are secured by mortgages on our natural gas and oil properties as well as a pledge of all ownership interests in our operating subsidiaries. We are required to maintain the mortgages on properties representing at least 80% of our natural gas and oil properties. Additionally, the obligations under the Credit Agreement are guaranteed by all of our operating subsidiaries and may be guaranteed by any future subsidiaries.

Borrowings under the Credit Agreement are available for acquisition and development of natural gas and oil properties, working capital, and general corporate purposes. At our election, interest is determined by reference to LIBOR plus an applicable margin between 1.00% and 1.75% per annum; or a domestic bank rate plus an applicable margin between 0% and .25% per annum.

As of June 21, 2006 we had outstanding indebtedness of $193.6 million under the credit facility and additional borrowing ability of $71.4 million.

Off Balance Sheet Arrangements

The Company did not have any off-balance sheet arrangements as of March 31, 2006.

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NON-GAAP FINANCIAL MEASURE

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) plus:

- Interest expense;
- Depreciation, depletion and amortization;
- Write-off of deferred financing fees;
- (Gain) loss on sale of assets;
- (Gain) loss from equity investment;
- Accretion of asset retirement obligation;
- Unrealized (gain) loss on natural gas derivatives;
- Realized (gain) loss on cancelled natural gas derivatives;
- Unit-based compensation expense;
- IPO bonuses; and
- Income tax provision.

The costs of cancelling natural gas swaps before their original settlement date are the only adjustments to Adjusted EBITDA that require expenditure of cash. These costs were financed with borrowings under our credit facility, and such long term debt is recognized as an increase in cash from financing activities.

Adjusted EBITDA is a significant performance metric used by our management to indicate (prior to the establishment of any reserves by our Board of Directors) the cash distributions we expect to pay our unitholders. Adjusted EBITDA is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies.

The following table presents a reconciliation of our consolidated net income (loss) to Adjusted EBITDA:

	Three Months Ended March 31,	
	2006	**2005**
	(Unaudited) (in thousands)	
Net income (loss)	$ 21,977	$ (12,399)
Plus:		
Interest expense	2,639	(20)
Depreciation, depletion and amortization	3,700	1,181
Write-off of deferred financing fees	374	
Loss on sale of assets	18	22
Loss from equity investment		10
Accretion of asset retirement obligation	58	25
Unrealized (gain) loss on natural gas derivatives	(20,923)	6,580
Realized (gain) loss on cancelled natural gas derivatives(1)		7,977
Unit-based compensation expense	5,680	

IPO bonuses	2,039	
Income tax provision(2)	119	
Adjusted EBITDA	$ 15,681	$ 3,376

(1) During the three months ended March 31, 2005, we cancelled (before their original settlement date) a portion of out-of-the-money natural gas swaps and realized a loss of $8.0 million. We subsequently hedged similar volumes at higher prices.

(2) Linn Operating, LLC was not subject to federal income tax before converting to a subchapter C-corporation on June 1, 2005. Prior to the conversion, there was no tax provision included in our consolidated financial statements because all of our taxable income or loss was included in the income tax returns of the individual members.

Cautionary Statement

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of federal securities laws that are subject to a number of risks and uncertainties, many of which are beyond our control. These statements may include statements about our:

- business strategy;
- financial strategy;
- drilling locations;
- natural gas and oil reserves;
- realized natural gas and oil prices;
- production volumes;
- lease operating expenses, general and administrative expenses and finding and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, are forward looking statements. These forward-looking statements may be found in Item 2. In some cases, you can identify forward-looking statements by terminology such as may, will, could, should, expect, plan, proj anticipate, believe, estimate, predict, potential, pursue, target, continue, the negative of such terms or ot comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties beyond our control. In addition, management s assumptions may prove to be inaccurate. We caution that the forward-looking statements contained in this Quarterly Report on Form 10-Q are not guarantees of future performance and that such statements may not be realized or the forward-looking statements or events may not occur. Actual results may differ materially from those anticipated or implied in forward looking statements due to factors listed in the Risk Factors section of our Annual Report on Form 10-K and throughout this Quarterly Report of Form 10-Q. These forward-looking statements speak only as of the date made, and other than as required by law, we undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas production. Realized pricing is primarily driven by the spot market prices applicable to our natural gas production and the prevailing price for crude oil. Pricing for natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control.

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We periodically have entered into and anticipate entering into hedging arrangements with respect to a portion of our projected natural gas production through various transactions that hedge the future prices received. These transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. At the settlement date, we receive the excess, if any, of the fixed floor over the floating rate. Additionally, we have put options for which we pay the counterparty the fair value at the purchase date. These hedging activities are intended to support natural gas prices at targeted levels and to manage our exposure to natural gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

Based on natural gas prices as of March 31, 2006, the fair value of our hedges which settle during the next twelve months was an asset of $7.5 million and a liability of $4.9 for a net asset of $2.6 million, which we are owed from the counterparty. A 10% increase in the index natural gas price above the March 31, 2006 price for the next twelve months would result in a change of $5.7 million for a liability of $3.1 million; conversely, a 10% decrease in the index natural gas price would increase the asset by approximately $5.7 million.

Our hedges for 2006 through 2009 are summarized in the table presented above under Item 2, Management s Discussion and Analysis of Financial Condition and Results of Operations Cash Flow from Operations in this Quarterly Report on Form 10-Q.

Interest Rate Risks

At March 31, 2006, we had debt outstanding of $158.0 million, which incurred interest at floating rates in accordance with our revolving credit facility. As of March 31, 2006, the one-month LIBOR was approximately 4.8%. A 1% increase in LIBOR as of March 31, 2006 would result in an estimated $1.6 million increase in annual interest expense.

In 2003, we entered into two interest rate swap agreements to minimize the effect of fluctuation in interest rates. The agreements have a notional amount of $30.0 million each. One of the interest rate swap agreements settled quarterly in 2005 and the second settles quarterly in 2006, and we are required to pay a rate of 3.2% and 4.3%, respectively, while receiving a floating rate. In 2004, we entered into two additional interest rate swap agreements with a notional amount of $50.0 million each. These interest rate swap agreements settle quarterly in 2007 and 2008, and we are required to pay a rate of 5.2% and 5.7%, respectively, while receiving a floating rate. In 2005, in connection with entering into a new credit facility, we transferred these four interest rate swap agreements to a different third party financial institution. As a consequence of the transfer of these four agreements, the fixed interest rate we pay on each agreement increased by seven basis points.

Also in 2004, we entered into two additional interest rate swap agreements with a notional amount of $20.0 million each. One of the agreements settled quarterly in 2005 and the second settles quarterly in 2006. We are required to pay a rate of 3.1% and 4.4%, respectively, while receiving a floating rate.

A 1% change in LIBOR as of March 31, 2006 would result in an estimated $1.5 million change in 2006 interest expense associated with our interest swap agreements.

Under the terms of the swap agreements, we receive quarterly interest payments at the three month LIBOR rate.

We did not specifically designate the interest rate swap agreements we entered into as hedges under SFAS No. 133, even though they protect us from changes in interest rates. Therefore, the mark to market of these instruments was recorded in our current earnings. Further, these amounts represent non-cash charges.

Item 4. Controls and Procedures.

***(a)* Evaluation of disclosure controls and procedures**

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the Company s reports under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to management, including the Company s Chief Executive Officer and Chief Financial Officer, and the Company s Audit Committee, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

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In connection with the preparation of the Company s Annual Report on Form 10-K for the year ended December 31, 2005 (2005 10-K), an evaluation was performed under the supervision and with the participation of the Company s management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act). The Company concluded that the disclosure controls and procedures were not effective as of December 31, 2005.

We carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on the evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of March 31, 2006, the Company s disclosure controls and procedures were not effective as a result of the previously identified material weaknesses. As reported in the 2005 10-K, management is in the process of taking remedial steps to correct the weaknesses.

Material weaknesses in internal control. Specifically, the Company lacked (i) personnel with sufficient technical accounting and financial reporting expertise, (ii) adequate review controls over account reconciliations and account analyses, (iii) policies and procedures in place to determine and document the appropriate application of accounting principles and (iv) policies and procedures requiring a detailed and comprehensive review of the underlying information supporting the amounts included in the annual and interim consolidated financial statements and disclosures.

***(b)* Changes and Remediation in the Company s Internal Control over Financial Reporting**

Remediation activities. During the first quarter of 2006, management identified the above material weaknesses in our internal control over financial reporting and management has taken and is taking the following steps to strengthen our internal control over financial reporting:

1. We engaged outside consultants with extensive natural gas and oil financial reporting experience to augment our current accounting resources to assist with the 2005 10-K, this quarterly report and future filings.

2. We performed additional analysis and other post closing procedures to enable the preparation of accurate consolidated financial statements, including all required disclosures.

Further as previously reported, we expect to continue to make changes in our internal control over financial reporting during the periods prior to December 31, 2007 in connection with our Section 404 compliance efforts. As such, we will continue to assess the adequacy of our internal control over financial reporting, remediate any control weaknesses that may be identified, validate through testing that controls are functioning as designed and implement a continuous reporting and improvement process for internal control over financial reporting.

The Company believes the measures taken to date and planned for the future will address the reported material weakness and intends to complete the remediation efforts during 2006.

Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting (as defined in Rule 13(a) 15(f) under the Exchange Act) during the three months ended March 31, 2006 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.

Not applicable.

Item 1A. Risk Factors

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our units are described under Risk Factors in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2005. This information should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

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

Not applicable.

Item 3. Defaults Upon Senior Securities

Not applicable.

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

Not applicable.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

10.1	Form of Unit Option Agreement pursuant to the Linn Energy, LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Linn Energy, LLC on February 21, 2006)
10.2	Memorandum of Understanding Regarding Compensation Arrangements for Members of the Linn Energy, LLC Board of Directors (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Linn Energy, LLC on February 21, 2006)
10.3	Employment Agreement, dated effective as of April 3, 2006 between Linn Operating, Inc. and Thomas A. Lopus (incorporation herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Linn Energy, LLC on April 18, 2006 (the April 18, 2006 Form 8-K)
10.4	Linn Energy, LLC Long-Term Incentive Plan Restricted Unit Agreement, dated effective as of April 13, 2006 between Linn Energy, LLC and Thomas A. Lopus (incorporated herein by reference to Exhibit 10.2 to the April 18, 2006 Form 8-K)
10.5	Linn Energy, LLC Long-Term Incentive Plan Option Agreement, dated effective as of April 13, 2006 between Linn Energy, LLC and Thomas A. Lopus (incorporated herein by reference to Exhibit 10.3 to the April 18, 2006 Form 8-K)
10.6	Separation Agreement and General Release, dated effective as of April 7, 2006 between Linn Energy, LLC and its subsidiaries and Gerald Merriam (incorporated herein by reference to Exhibit 10.4 to the April 18, 2006 Form 8-K)
10.7	Separation Agreement and General Release, dated effective as of April 7, 2006 between Linn Energy, LLC and its subsidiaries and Gerald Merriam (incorporated herein by reference to Exhibit 10.4 to the April 18, 2006 Form 8-K)
10.8	First Amendment to Amended and Restated Credit Agreement among Linn Energy, LLC as Borrower, BNP Paribas, as Administrative Agent, and the Lender signatory thereto, effective as of May 5, 2006 (incorporated herein by reference to Exhibit 10.23 to the Annual Report on Form 10-K filed by Linn Energy, LLC on

	May 31, 2006)
31.1	Certification of Michael C. Linn, Chairman, President and Chief Executive Officer of Linn Energy, LLC.
31.2	Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC.
32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Michael C. Linn, Chairman, President and Chief Executive Officer of Linn Energy, LLC.
32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC.

Management contract or compensatory plan or arrangement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, in the City of Pittsburgh, State of Pennsylvania, on June 30, 2006.

LINN ENERGY, LLC

By: /s/ Michael C. Linn
Michael C. Linn
Chairman, President and Chief Executive Officer

By: /s/ Kolja Rockov
Kolja Rockov
Executive Vice President and Chief Financial Officer