Linn Energy, LLC
Form 10-Q
August 15, 2006

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

x	**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the Quarterly Period Ended June 30, 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 x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer o Accelerated filer o Non-accelerated filer x

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

As of August 1, 2006, there were 27,882,500 units outstanding.

TABLE OF CONTENTS

		Page
	Glossary of Terms	3
	Part I - Financial Information	
Item 1.	Financial Statements	
	Condensed Consolidated Balance Sheets as of June 30, 2006 (Unaudited) and December 31, 2005	5
	Condensed Consolidated Statements of Operations for the three and six months ended June 30, 2006 and 2005 (Unaudited)	7
	Condensed Consolidated Statements of Unitholders Capital for the six months ended June 30, 2006 (Unaudited)	8
	Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2006 and 2005 (Unaudited)	9
	Notes to Condensed Consolidated Financial Statements (Unaudited)	10
Item 2.	Management s Discussion and Analysis of Financial Condition and Results of Operations	21
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	33
Item 4.	Controls and Procedures	35
	Part II - Other Information	
Item 1.	Legal Proceedings	37
Item 1A.	Risk Factors	37
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	49
Item 3.	Defaults Upon Senior Securities	49
Item 4.	Submission of Matters to a Vote of Security Holders	49
Item 5.	Other Information	49
Item 6.	Exhibits	50
	Signature	52

GLOSSARY OF TERMS

As commonly used in the natural gas and oil industry and as used in this Quarterly Report on Form10-Q, the following terms have the following meanings:

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

Bcf. One billion cubic feet.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Bbl. One barrel of crude oil or other liquid hydrocarbons.

Btu. One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Development well. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dth. One decatherm, equivalent to one million British thermal units.

Developed acres. Acres spaced or assigned to productive wells.

Dry hole or *well.* A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or *gross wells.* The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfe/d. One MMcfe per day.

MMMBtu. One billion British thermal units.

Net acres or *net wells.* The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NYMEX. The New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional natural gas and oil expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Proved natural gas and oil reserves are the estimated quantities of natural gas, natural gas liquids and crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions.

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves or *PUDs.* Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reservoir. A porous and permeable underground formation containing a natural accumulation of produceable natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Standardized Measure. Standardized Measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission (using prices and costs in effect as of the date of estimation) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Our Standardized Measure does not include future income tax expenses because our reserves are owned by our subsidiary Linn Energy Holdings, LLC, which is not subject to income taxes.

Successful well. A well capable of producing natural gas and/or oil in commercial quantities.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

Part I FINANCIAL INFORMATION

Item 1. Financial Statements

LINN ENERGY, LLC

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2006 (Unaudited) (in thousands)	December 31, 2005
Assets		
Current assets:		
Cash and cash equivalents	$ 3,635	$ 11,041
Receivables:		
Natural gas and oil, net of allowance for doubtful accounts of $100,000 as of June 30, 2006 and December 31, 2005	9,428	17,103
Other	332	650
Fair value of interest rate swaps	376	202
Inventory	212	68
Current portion of natural gas derivatives	12,041	1,601
Other current assets	960	4,068
Total current assets	26,984	34,733
Natural gas and oil properties and related equipment	315,264	250,000
Less accumulated depreciation, depletion, and amortization	18,190	10,707
	297,074	239,293
Property and equipment, net	5,932	2,525
Other assets:		
Long-term portion of natural gas derivatives	13,385	2,795
Deferred tax assets, net	307	
Operating bonds	197	198
	13,889	2,993
Total assets	$ 343,879	$ 279,544

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2006 (Unaudited) (in thousands)	December 31, 2005
Liabilities and Unitholders Capital (Deficit)		
Current liabilities:		
Current portion of long-term notes payable	$ 635	$ 113
Subordinated term loan		59,501
Accounts payable and accrued expenses	5,092	5,572
Current portion of natural gas derivatives	4,413	12,094
Revenue distribution	1,193	6,082
Accrued interest payable	2,173	1,448
Gas purchases payable	877	1,208
Other current liabilities	40	40
Total current liabilities	14,423	86,058
Long-term liabilities:		
Long-term portion of notes payable	2,068	695
Credit facility	191,858	206,119
Long-term portion of interest rate swaps	90	663
Asset retirement obligation	5,753	5,443
Long-term portion of natural gas derivatives	18,498	27,139
Other long-term liabilities	473	258
Total long-term liabilities	218,740	240,317
Total liabilities	233,163	326,375
Unitholders capital (deficit):		
27,832,500 units issued and outstanding at June 30, 2006	141,355	16,024
Accumulated loss	(30,639)	(62,855)
	110,716	(46,831)
Total liabilities and unitholders capital (deficit)	$ 343,879	$ 279,544

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three months ended June 30, 2006	2005	Six months ended June 30, 2006	2005
	(in thousands, except unit and per unit amounts)			
Revenues:				
Natural gas and oil sales	$ 13,529	$ 7,855	$ 29,904	$ 14,001
Realized gain (loss) on natural gas derivatives	5,840	(8,189)	9,163	(16,764)
Unrealized gain (loss) on natural gas derivatives	7,055	1,197	27,978	(5,383)
Natural gas marketing income	1,346	655	2,564	1,469
Other income	204	64	493	138
	27,974	1,582	70,102	(6,539)
Expenses:				
Operating expenses	2,933	1,488	5,927	3,305
Natural gas marketing expense	1,189	604	2,172	1,394
General and administrative expenses	6,928	670	16,398	1,148
Depreciation, depletion and amortization	4,116	1,406	7,816	2,587
	15,166	4,168	32,313	8,434
	12,808	(2,586)	37,789	(14,973)
Other income and (expenses):				
Interest income	92	3	238	3
Interest and financing expense	(2,696)	(2,304)	(5,335)	(2,284)
Write-off of deferred financing fees and other losses	(158)	(389)	(550)	(421)
	(2,762)	(2,690)	(5,647)	(2,702)
Income (loss) before income taxes	10,046	(5,276)	32,142	(17,675)
Income tax benefit	193		74	
Net income (loss)	$ 10,239	$ (5,276)	$ 32,216	$ (17,675)
Net income (loss) per unit - basic	$ 0.37	$ (0.26)	$ 1.19	$ (0.86)
Net income (loss) per unit - diluted	$ 0.36	$ (0.26)	$ 1.18	$ (0.86)
Weighted average units outstanding - basic	27,829,863	20,518,065	27,055,515	20,518,065
Weighted average units outstanding - diluted	28,093,798	20,518,065	27,325,341	20,518,065
Distributions declared per unit	$ 0.32	$	$ 0.32	$

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENT OF UNITHOLDERS CAPITAL (DEFICIT)

(Unaudited)

	Unitholders Capital (in thousands)	Accumulated Loss	Treasury Units (at Cost)	Total Unitholders Capital (Deficit)
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 units			(114,449)	(114,449)
Cancellation of member units	(100,778)		100,778	
Distribution to members	(8,826)			(8,826)
Unit-based compensation expense	9,796			9,796
Net income		32,216		32,216
Balance as of June 30, 2006	$ 141,355	$ (30,639)		$ 110,716

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six months ended June 30, 2006	2005
	(in thousands)	
Cash flow from operating activities:		
Net income (loss)	$ 32,216	$ (17,675)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	7,816	2,587
Amortization of deferred financing fees	309	90
Write-off of deferred financing fees	503	389
Accretion of asset retirement obligation	119	57
Unrealized (gain) loss on natural gas and interest rate derivatives	(28,725)	5,367
Unit-based compensation	9,796	
Deferred income tax	(307)	
Changes in assets and liabilities:		
Decrease in accounts receivable	7,993	412
(Increase) decrease in other assets	3,809	(862)
Increase (decrease) in accounts payable and accrued expenses	(5,791)	70
(Decrease) in natural gas and interest rate derivatives	(9,374)	(732)
(Decrease) in revenue distribution	(4,889)	(324)
Increase in accrued interest payable	725	572
Increase (decrease) in gas purchases payable	(331)	73
Increase in asset retirement obligation	8	15
Increase in other liabilities	215	
Net cash provided by (used in) operating activities	14,092	(9,961)
Cash flow from investing activities:		
Acquisition and development of natural gas and oil properties	(65,079)	(13,321)
Purchases of property and equipment	(1,668)	(384)
Obligations related to drilling activities	971	
Proceeds from sale of assets	25	73
Other investing activities		(68)
Net cash (used in) investing activities	(65,751)	(13,700)
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	(60,516)	(5,279)
Proceeds from credit facility	48,303	101,400
Principal payment on credit facility	(62,000)	(75,605)
Distribution to members	(8,826)	
Deferred offering costs	(844)	(1,366)
Deferred financing fees	(564)	(165)
Net cash provided by financing activities	44,253	23,985
Net increase (decrease) in cash	(7,406)	324
Cash and cash equivalents:		
Beginning	11,041	2,188
Ending	$ 3,635	$ 2,512
Supplemental disclosure of cash flow information:		
Cash payments for interest	$ 4,957	$ 1,690
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	$ 184	$ 112
Acquisition of vehicles and equipment through issuance of notes payable	$ 2,097	$

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

LINN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

(1) Basis of Presentation

The condensed consolidated financial statements at June 30, 2006, and for the three and six months ended June 30, 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 (GAAP) have been condensed or omitted under Securities and Exchange Commission (SEC) 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. Certain amounts in the consolidated financial statements and notes thereto have been reclassified to conform to the 2006 financial statement presentation.

(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 long-lived properties in the United States. We operate primarily in the Appalachian Basin, including in West Virginia, Pennsylvania, New York and Virginia, with recent acquisitions in California and Oklahoma (see Note 3). As of June 30, 2006, Linn s wholly owned subsidiaries included 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 GAAP. 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, as amended, *Financial Accounting and Reporting by Oil and Gas Producing Companies,* 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 accounts for asset retirement obligations in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143). In accordance with 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.

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 three or six months ended June 30, 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. No impairments were recorded during the three or six months ended June 30, 2006 or 2005.

(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. An independent engineering firm prepares a reserve and economic evaluation of all the Company s properties on a well-by-well basis.

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 noted above adheres to the same guidelines when preparing its 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 or its subsidiaries that are organized as limited liability companies have been provided for in the accompanying financial statements except as described below.

Certain of the Company s 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 $0.3 million and $74,000 are recorded in other long-term liabilities on the consolidated balance sheets at June 30, 2006 and December 31, 2005, respectively. At June 30, 2006, deferred tax assets of approximately $0.3 million, net of a valuation allowance of $1.2 million, are recorded to the extent of existing deferred tax liabilities.

(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 June 30, 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.

(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 its initial public offering (IPO), equivalent units were calculated by adjusting pre-IPO members membership interests by the exchange ratio to reflect the exchange of pre-IPO membership interests for post-IPO units and cash immediately prior to completion of the IPO (see Note 4). 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 three and six months ended June 30, 2006, all unit options outstanding were excluded in the computation of diluted earnings per unit, because to do so would have been antidilutive for the periods. For the three and six months ended June 30, 2006, the effect of unvested units awarded but not issued to the Chief Executive Officer were included in the computation of diluted earnings per unit. The dilutive effect of these unit equivalents was 263,935 units and 269,826 units, for a total of 28,093,798 and 27,325,341 diluted units outstanding for the three and six months ended June 30, 2006, respectively.

(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 condensed consolidated financial statements in conformity with GAAP. 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, depreciation, depletion and amortization, asset retirement obligations, the fair value of derivatives and unit awards.

(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 June 30, 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 and natural gas marketing expense, titled as such, are reported on the consolidated statement of operations for the three and six months ended June 30, 2006 and 2005.

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 portion of the fee that exceeds the reimbursement of operating costs has been netted against general and administrative expense. For the three and six months ended June 30, 2006, the operating fees netted against general and administrative expense were approximately $352,000 and $636,000 respectively. For the three and six months ended June 30, 2005, the operating fees netted against general and administrative expense were approximately $222,000 and $509,000, respectively.

(k) ***Unit-Based Compensation***

See Note 9 for a discussion of the accounting for unit-based compensation expense.

(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 154). SFAS 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 Company s results of operations and financial condition.

In February 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 155, *Accounting for Certain Hybrid Instruments, (an Amendment of FASB Statements No. 133 and140)* (SFAS 155). The standard allows financial instruments that have embedded derivatives to be accounted for as a whole, eliminating the need to bifurcate the derivative from its host, if the holder elects to account for the whole instrument on a fair value basis. SFAS 155 also establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation. The standard is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. The Company is currently evaluating the effect that the adoption of SFAS 155 will have on its results of operations and financial condition, but does not expect it will have a material impact.

In June 2006, the FASB issued Financial Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109* (FIN 48). The interpretation sets forth a consistent recognition threshold and measurement attribute, and criteria for subsequently recognizing, derecognizing and measuring uncertain tax positions for financial statement purposes. FIN 48 also requires expanded disclosure with respect to the uncertainty in income taxes. The interpretation is effective for fiscal years beginning after December 31, 2006. The Company is currently evaluating the effect that the adoption of FIN 48 will have on its results of operations and financial condition, but does not expect it will have a material impact.

(3) Acquisitions

In the second quarter of 2006, the Company purchased from the owners of property operated by Devonian Gas Production, Inc., Excel Energy, Inc. and T&F Exploration LP, a total of 200 producing wells and tangible wellhead equipment in West Virginia, for an aggregate purchase price of approximately $27.5 million, subject to customary post-closing adjustments. Also in the second quarter of 2006, the Company purchased a natural gas gathering pipeline system in western Pennsylvania for approximately $0.8 million.

In August 2006, the Company acquired certain affiliated entities of Blacksand Energy, LLC ("Blacksand Assets"), located in the Los Angeles Basin, for approximately $291.0 million and certain Mid-Continent assets of Kaiser-Francis Oil Company ("Kaiser Assets") located in Oklahoma for approximately $125.0 million, in both cases subject to customary post-closing adjustments. The acquisitions of the Kaiser Assets and Blacksand Assets were financed with a combination of borrowings under our secured revolving credit facility and a $250.0 million subordinated bridge loan. In connection with the acquisitions, we entered into a new agreement that increased the credit facility from $400.0 million to $800.0 million and increased the borrowing base from $265.0 million to $480.0 million (see Note 6).

(4) Initial Public Offering

In the first quarter of 2006, the Company completed its IPO of 12,450,000 units representing limited liability interest in the Company at $21.00 per unit, for net proceeds, after underwriting discounts of approximately $18.3 million and offering expenses of $4.3 million, of approximately $238.8 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 and approximately $2.0 million was used to pay bonuses to certain executive officers of the Company.

(5) Natural Gas and Oil Properties

	June 30, 2006 (in thousands)	December 31, 2005
Unproved properties	$ 4,964	$ 4,562
Proved developed properties:		
Acquisition, equipment and drilling	303,525	239,858
Pipelines	6,775	5,580
	315,264	250,000
Less accumulated depletion, depreciation and amortization	(18,190)	(10,707)
	$ 297,074	$ 239,293

(6) Debt

Credit Facility

At June 30, 2006 the Company had a $400.0 million credit facility, with a maturity of April 2009, with the amount available for borrowing at any one time limited to a borrowing base of $265.0 million. In August 2006, in connection with the acquisitions of the Blacksand Assets and the Kaiser Assets (see Note 3), the Company entered into an incremental senior secured revolving credit facility and extended the maturity to August 2010 (Credit Facility), including an increase in the facility to $800.0 million and an increase in the borrowing base to $480.0 million. We also entered into a subordinated bridge loan (see Subordinated Bridge Loan below).

The terms under the incremental Credit Facility remain substantially the same as the previous terms. The borrowing base under the Credit Facility 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 Facility 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 Facility are guaranteed by all of our operating subsidiaries and may be guaranteed by any future subsidiaries.

At our election, interest on the Credit Facility 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 0.00% and 0.25% per annum. LIBOR margins increase by 0.25% while the subordinated bridge loan is outstanding. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

The Credit Facility 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 Facility also contains covenants that, among other things, require us to maintain specified financial ratios, including a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) of 2.0 to 1.0 while the subordinated bridge loan (see below) is outstanding. The Company is in compliance with all financial and other covenants of its Credit Facility.

As of June 30, 2006 and December 31, 2005, the credit facility consisted of the following:

	June 30, 2006 (in thousands)	December 31, 2005
Outstanding balance	$ 193,000	$ 207,000
Less deferred financing fees, net of amortization of $463,000 and $160,000	(1,142)	(881)
	$ 191,858	$ 206,119

Total accrued interest on the credit facility and the subordinated term loan (see below) was approximately $2.2 million and $1.4 million at June 30, 2006 and December 31, 2005, respectively.

Subordinated Bridge Loan

In August 2006, in order to fund a portion of the acquisitions of the Blacksand Assets and the Kaiser Assets, we entered into a $250.0 million subordinated bridge loan (Subordinated Bridge Loan) with a termination of August 1, 2007. Financial covenants under the Subordinated Bridge Loan are substantially similar to those under the Credit Facility. At our election, interest is determined by reference to LIBOR plus an applicable margin of 4.00% per annum; or a domestic bank rate plus an applicable margin of 2.50% per annum. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

Subordinated Term Loan

During 2005, the Company had a facility for a $60.0 million second lien senior subordinated term loan. 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 IPO.

(7) Long-term Notes Payable

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

	June 30, 2006 (in thousands)	December 31, 2005
Note payable to a bank with an interest rate of 6.14%, payable in monthly installments of approximately $3,000, including interest, through September 2024. The note is secured by an office building	$ 381	$ 387
Various notes for the purchase of vehicles and equipment, payable in monthly installments totaling approximately $63,000 and $11,000, as of June 30, 2006 and December 31, 2005, respectively, including interest. The interest rates range from 0-8.87%. The notes are secured by the vehicles and equipment purchased and expire at various dates from 2008 through 2011	2,322	421
	2,703	808
Less current portion	(635)	(113)
	$ 2,068	$ 695

15

As of June 30, 2006, maturities on the aforementioned long-term notes payable were as follows:

June 30:	(in thousands)
2006	$ 635
2007	856
2008	333
2009	329
2010	237
Thereafter	313
	$ 2,703

(8) 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 and six months ended June 30, 2006, the Company s two largest customers represented approximately 65% and 9%, and 68% and 10%, respectively, of the Company s sales. The Company s three largest customers represented approximately 28%, 23%, and 17%, and 30%, 19% and 18%, of the Company s sales for the three and six months ended June 30, 2005, respectively.

At June 30, 2006, two customers trade accounts receivable from natural gas sales accounted for more than 10% of the Company s total trade accounts receivable. At June 30, 2006, trade accounts receivable from these customers represented approximately 64%, and 15% of the Company s receivables. At December 31, 2005, two customers trade accounts receivable from natural gas sales accounted for more than 10% of the Company s total trade accounts receivable. At December 31, 2005, trade accounts receivable from these customers represented approximately 70%, and 13% of the Company s receivables.

(9) Unit-Based Compensation

Incentive Plan Summary

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 of Directors 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

16

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.

Phantom Units/Unit Appreciation Rights These awards 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 service 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.

Securities Authorized for Issuance Under the Plan

As of June 30, 2006, approximately 1.5 million units were issuable under the Plan pursuant to outstanding award or other agreements and an additional 2.4 million units were reserved for issuance under the Plan.

Accounting for Unit-Based Compensation

SFAS No. 123(R), (revised 2004), *Share-Based Payment* ("SFAS 123R"), was effective January 1, 2006. SFAS 123R requires an entity to recognize expense at the grant date, the fair value of unit options and other equity-based compensation issued to employees. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period using the straight-line method in the Company s consolidated statement of operations.

SFAS 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 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 *Accounting for Stock-Based Compensation.* 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 and six months ended June 30, 2006, we recorded unit-based compensation expense of approximately $4.2 million and $9.9 million, respectively, as a charge against income before income taxes and it is included in general and administrative expense on the consolidated statement of operations. No related income tax benefit was recognized due to Internal Revenue Code Section 162(m) deductibility limits and recognition of a valuation allowance for resulting net operating losses. The Company recorded no unit-based compensation for the three and six months ended June 30, 2005, as there were no unit-based awards granted during those periods.

Restricted/Unrestricted Units

The fair value of unrestricted unit grants and restricted units issued is determined based on the fair market value of the Company 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 June 30, 2006, and changes during the six months ended June 30, 2006, is presented below:

	Number of Non-vested Units	Weighted Average Grant-Date Fair Value
Non-vested units at December 31, 2005		$
Granted	989,145	21.23
Vested	(114,455)	21.00
Forfeited		
Non-vested units at June 30, 2006	874,690	$ 21.26

As of June 30, 2006, there was approximately $11.4 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of approximately 0.8 years.

Changes in Unit Options and Unit Options Outstanding

The following table provides information related to unit option activity for the six months ended June 30, 2006:

	Number Units of 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	531,084	20.57	3.04	10.00
Exercised				
Vested				
Forfeited	(41,750)	20.18	2.52	10.00
Outstanding at June 30, 2006	489,334	$ 20.60	$ 3.09	10.00
Exercisable at June 30, 2006	30,000	$ 20.18	$ 2.52	10.00

As of June 30, 2006, there was approximately $1.1 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 approximately 1.7 years. In addition, the exercisable unit options at June 30, 2006 have an aggregate intrinsic value of approximately $23,000 and all outstanding unit options have an aggregate intrinsic value of approximately $184,000. No options expired during the period.

Subsequent to June 30, 2006, the Company granted an aggregate 50,000 unit options and 50,000 restricted units to an executive officer. Subsequent to June 30, 2006, the Company granted an aggregate 9,000 phantom units to independent members of the Board of Directors.

The fair value of unit-based compensation for unit options was estimated on the date of grant using a Black-Scholes pricing model based on certain assumptions. The Company s determination of fair value of unit-based payment awards is affected by the Company s unit price as well as assumptions regarding a number of highly complex and subjective variables. The Company s employee unit options have various restrictions including vesting provisions and restrictions on transfers and hedging, among others, and often are expected to be exercised prior to their contractual maturity. Expected volatilities used in the estimation of fair value have been determined using 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 forfeitures used in the Black-Scholes pricing model. Forfeitures are revised, if necessary, in subsequent periods if actual forfeitures differ from estimates. 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 unit option grants were based upon the following assumptions:

Expected volatility	29.70-30.40	%
Expected dividends	7.20%-8.10	%
Expected term (in years)	5.00	
Risk free rate	4.31%-4.97	%
Expected forfeiture rate	23.10	%

Although the fair value of unit option grants is determined in accordance with SFAS 123R 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.

(10) Property and Equipment

Property and equipment consists of the following:

	June 30, 2006	**December 31, 2005**
	(in thousands)	
Land	$ 308	$ 203
Buildings and leasehold improvements	1,194	608
Vehicles	2,277	1,317
Drilling equipment not yet in service	1,749	
Furniture and equipment	1,192	888
	6,720	3,016
Less: accumulated depreciation	(788)	(491)
	$ 5,932	$ 2,525

Depreciation expense for the three and six months ended June 30, 2006 was approximately $201,000 and $354,000, respectively. Depreciation expense for the three and six months ended June 30, 2005 was approximately $71,000 and $124,000 respectively.

(11) 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 and six months ended June 30, 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.

(12) 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.

Settled derivatives on production for the three and six months ended June 30, 2006 included a volume of 4,054 MMMBtu and 2,035 MMMBtu at an average price of $9.22 and $9.22, respectively. 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 third day of the production month. The following table summarizes open positions as of June 30, 2006 and represents, as of such date, our derivatives in place through December 31, 2009:

	July 1 December 31, 2006	Year 2007	Year 2008	Year 2009
Fixed Price Swaps:				
Hedged Volume (MMMBtu)	3,720	7,168	8,464	6,205
Average Price ($/MMBtu)	$ 9.25	$ 8.64	$ 8.23	$ 7.56
Puts:				
Hedged Volume (MMMBtu)	368	2,336	2,013	
Average Price ($/MMBtu)	$ 8.83	$ 9.11	$ 9.50	
Total:				
Hedged Volume (MMMBtu)	4,088	9,504	10,477	6,205
Average Price ($/MMBtu)	$ 9.21	$ 8.75	$ 8.47	$ 7.56

The natural gas derivatives are not designated as cash flow hedges under SFAS No. 133, *Accounting for Derivatives and Hedging Activity* (SFAS 133), and, accordingly, the changes in fair value are recorded in current period earnings.

The following table presents the outstanding notional amounts and maximum number of months outstanding of our derivatives:

	June 30, 2006	December 31, 2005
Outstanding notional amounts of hedges (MMMBtu)	30,274	28,069
Maximum number of months hedges outstanding	42	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.

(13) Related Party

For the three and six months ended June 30, 2006, the Company made payments of approximately $182,000 and $242,000, respectively, to a company owned by one of our senior executives. The payments reflect reimbursement for maintenance and hourly usage fees for business use of transportation services and an asset which is partially owned by the senior executive. These costs are included in general and administrative expense on the consolidated statement of operations. The transactions were consummated on terms equivalent to those that prevail in arm s-length transactions.

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

Results of Operations - Executive Summary

Acquisitions and Strategy

We are an independent natural gas and oil company focused on the development and acquisition of long-lived properties in the United States. We operate primarily in the Appalachian Basin, including in West Virginia, Pennsylvania, New York and Virginia, with recent acquisitions in California and Oklahoma. 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 net proceeds after underwriting discounts and offering expenses of approximately $238.8 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 and approximately $2.0 million was used to pay bonuses to certain executive officers of the Company.

From inception through June 30, 2006, we had completed 12 acquisitions of natural gas properties and related gathering and pipeline assets for an aggregate purchase price of approximately $229.0 million, with total proved reserves of 177.6 Bcfe, or an acquisition cost of $1.29 per Mcfe.

Date	Seller	Gross Wells	Location	Purchase Price (in millions)
May 2003	Emax Oil Company	34	West Virginia	$ 3.2
August 2003	Lenape Resources, Inc.	61	New York	2.2
September 2003	Cabot Oil & Gas Corporation	50	Pennsylvania	15.8
October 2003	Waco Oil & Gas Company	353	West Virginia and Virginia	31.5
May 2004	Mountain V Oil & Gas, Inc.	251	Pennsylvania	12.5
September 2004	Pentex Energy, Inc.	447	Pennsylvania	15.1
April 2005	Columbia Natural Resources, LLC	38	West Virginia and Virginia	4.4
August 2005	GasSearch Corporation	130	West Virginia	5.4
October 2005	Exploration Partners, LLC	550	West Virginia and Virginia	111.4
April 2006	Excel Energy, Inc.	106	West Virginia	7.5
April 2006	T&F Exploration LP	13	West Virginia	0.9
May 2006	Devonian Gas Production, Inc.	81	West Virginia	19.1
	Total	2,114		$ 229.0

In August 2006, the Company acquired certain affiliated entities of Blacksand Energy, LLC (Blacksand Assets), located in the Los Angeles Basin, for approximately $291.0 million and certain Mid-Continent assets of Kaiser-Francis Oil Company (Kaiser Assets) located in Oklahoma for approximately $125.0 million, in both cases subject to customary post-closing adjustments.

Our acquisitions were financed with a combination of 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. Because of our rapid growth through acquisitions and accelerated 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 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 producers. 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. The Company performs certain activities in connection with its drilling of oil and gas wells, which includes preparing and clearing well sites, providing drilling engineers, roustabouts and other personnel necessary for drilling. The Company has received its first drilling rig and has two additional rigs ordered, which will reduce or eliminate reliance on contract rigs. 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 ultimately realized. 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.

Operations

Our revenues are highly sensitive to changes in natural gas prices and levels of production. As of June 30, 2006, we have hedged a significant portion of our expected production using natural gas derivatives, which allows us to mitigate, but not eliminate, commodity 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. See Item 3. Qualitative and Quantitative Disclosures About Market Risk for derivatives entered into subsequent to June 30, 2006, in connection with our acquisition of the Blacksand Assets.

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 analyze 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 - Three Months Ended June 30, 2006 Compared to Three Months Ended June 30, 2005

The following table sets forth selected financial data for the periods indicated:

	Three Months Ended June 30, 2006 (in thousands) (Unaudited)	2005	Variance
Revenues:			
Natural gas and oil sales	$ 13,529	$ 7,855	$ 5,674
Realized gain (loss) on natural gas derivatives	5,840	(8,189)	14,029
Unrealized gain on natural gas derivatives	7,055	1,197	5,858
Natural gas marketing income	1,346	655	691
Other income	204	64	140
Total revenue	27,974	1,582	26,392
Expenses:			
Operating expenses	$ 2,933	$ 1,488	$ 1,445
Natural gas marketing expense	1,189	604	585
General and administrative expenses	6,928	670	6,258
Depreciation, depletion and amortization	4,116	1,406	2,710
Total expenses	15,166	4,168	10,998
Other Income and (Expenses):			
Interest and financing expense	$ (2,696)	$ (2,304)	$ (392)

The following table sets forth selected operating data for the periods indicated:

	Three Months Ended June 30, 2006	2005	Percentage Increase (Decrease)
Net Production:			
Total production (MMcfe)	1,956	1,103	77.3 %
Average daily production (Mcfe/d)	21,500	12,200	76.2 %
Average Sales Prices:			
Weighted average realized natural gas price (Mcfe)	$ 9.90	$ 6.19	59.9 %
Average Unit Costs per Mcfe (Non-GAAP):			
Operating expenses	$ 1.50	$ 1.35	11.1 %
General and administrative expenses (1)	$ 1.40	$ 0.61	*
Depreciation, depletion and amortization	$ 2.10	$ 1.27	65.4 %

(1) This is a non-GAAP performance measure used by our management and is a quantitative measure used in the natural gas and oil industry. The measure for the three months ended June 30, 2006 excludes approximately $4.2 million of unit-based compensation expense primarily resulting from January 2006 awards to certain executive officers in connection with our IPO. General and administrative expenses including these amounts were $3.54 per Mcfe for the three months ended June 30, 2006.

* Amount is greater than 100%, therefore is not meaningful.

Revenue

Natural gas and oil sales increased to approximately $13.5 million from $7.9 million during the three months ended June 30, 2006 as compared to the three months ended June 30, 2005.

The increase in revenue from natural gas and oil sales was attributable primarily to the increase in production to 1,956 MMcfe during the three months ended June 30, 2006 from 1,103 MMcfe during the three months ended June 30, 2005, the three acquisitions completed in 2005, and the drilling of 84 wells during 2006 (through June 30) and 110 wells in 2005. In addition to the increase in production, the average natural gas sales price increased during the three months ended June 30, 2006, as compared to the three months ended June 30, 2005.

Hedging Activities

During the three months ended June 30, 2006, we have effectively hedged 95% of our natural gas production, which resulted in revenues that were $5.8 million greater than we would have achieved at unhedged prices. During the three months ended June 30, 2005, we hedged approximately 100% of our natural gas production, which resulted in revenues that were $8.2 million less than we would have achieved at unhedged prices. Unrealized gains on derivatives in the amounts of $7.1 million and $1.2 million for the three months ended June 30, 2006 and 2005, respectively, were also recorded. Unrealized gains and losses result from natural gas price fluctuations as compared to the settlement price on the derivative.

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 $2.9 million for the three months ended June 30, 2006 from $1.5 million for the three months ended June 30, 2005, due to the increase in the number of wells as a result of the three acquisitions completed in both 2006 and in 2005 and the drilling of 84 wells during 2006 (through June 30) and 110 wells during 2005.

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 $6.9 million from $0.7 million during the three months ended June 30, 2006 as compared to the three months ended June 30, 2005. General and administrative expenses are presented net of approximately $0.4 million and $0.2 million, during the three months ended June 30, 2006 and 2005, respectively, which represent operating expense reimbursements from other working interest owners. The increase in general and administrative expenses was due to the recognition of unit-based compensation expense of $4.2 million during the three months ended June 30, 2006, to our rapidly growing operations and increasing our staffing level to manage the additional wells acquired and drilled in 2006 and 2005, and to perform the functions associated with being a public company.

Depreciation, depletion and amortization increased to $4.1 million for the three months ended June 30, 2006 from $1.4 million for the three months ended June 30, 2005, due to the increase in the number of wells as a result of the acquisitions completed and the wells drilled in 2006 and 2005, as noted above. During the three months ended June 30, 2006 and 2005, the Company capitalized approximately $0.6 million and $0.4 million, respectively, of internal costs related to drilling.

Interest and financing income (expense) was a net expense of $2.7 million for the three months ended June 30, 2006 as compared to a net expense of $2.3 million for the three months ended June 30, 2005. Our interest rate swaps were not specifically designated as hedges under SFAS 133, even though they reduce our exposure to changes in interest rates. Therefore, the mark-to-market of these instruments was recorded as a gain of $0.3 million and loss of $0.9 million for the three months ended June 30, 2006 and 2005, respectively. Further, these amounts represent non-cash charges. Cash payments for interest expense increased to $1.6 million for the three months ended June 30, 2006 from $0.4 million for the three months ended June 30, 2005, primarily due to increased debt levels associated with the acquisitions completed and the drilling of wells during the 2006 and 2005.

Income tax was a benefit of approximately $193,000 for the three months ended June 30, 2006, resulting from the recognition of deferred tax assets arising from net operating losses which are expected to be realized to the extent of deferred tax liabilities arising from bases differences in property and equipment. Deferred tax assets exceeding deferred tax liabilities of

$0.3 million have been offset by an increase in the valuation allowance during the three months ended June 30, 2006. Because we were structured as a limited liability company through May 31, 2005, no tax provision was recorded during the three months ended June 30, 2005 because all of our taxable income or loss is reportable 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 benefit and expense relates to the income attributable to those entities.

Results of Operations - Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

The following table sets forth selected financial data for the periods indicated:

	Six Months Ended June 30, 2006 (in thousands) (Unaudited)	2005	Variance
Revenues:			
Natural gas and oil sales	$ 29,904	$ 14,001	$ 15,903
Realized gain (loss) on natural gas derivatives	9,163	(16,764)	25,927
Unrealized gain (loss) on natural gas derivatives	27,978	(5,383)	33,361
Natural gas marketing income	2,564	1,469	1,095
Other income	493	138	355
Total revenue	70,102	(6,539)	76,641
Expenses:			
Operating expenses	$ 5,927	$ 3,305	$ 2,622
Natural gas marketing expense	2,172	1,394	778
General and administrative expenses	16,398	1,148	15,250
Depreciation, depletion and amortization	7,816	2,587	5,229
Total expenses	32,313	8,434	23,879
Other Income and (Expenses):			
Interest and financing expense	$ (5,335)	$ (2,284)	$ (3,051)

The following table sets forth selected operating data for the periods indicated:

	Six Months Ended June 30, 2006	2005	Percentage Increase (Decrease)
Net Production:			
Total production (MMcfe)	3,792	2,075	82.7 %
Average daily production (Mcfe/d)	21,000	11,463	83.2 %
Average Sales Prices:			
Weighted average realized natural gas price (Mcfe)	$ 10.30	$ 5.95	73.1 %
Average Unit Costs per Mcfe (Non-GAAP):			
Operating expenses	$ 1.56	$ 1.59	(1.9)%
General and administrative expenses (1)	$ 1.18	$ 0.55	*
Depreciation, depletion and amortization	$ 2.06	$ 1.25	64.8 %

(1) This is a non-GAAP performance measure used by our management and is a quantitative measure used in the natural gas and oil industry. The measure for the six months ended June 30, 2006 excludes approximately $2.0 million of bonuses paid to certain executive officers in connection with our IPO and $9.9 million of unit-based compensation expense. General and administrative expenses including these amounts were $4.32 per Mcfe for the six months ended June 30, 2006.

* Amount is greater than 100%, therefore is not meaningful.

Revenue

Natural gas and oil sales increased to approximately $29.9 million from $14.0 million during the six months ended June 30, 2006 as compared to the six months ended June 30, 2005.

The increase in revenue from natural gas and oil sales was attributable primarily to the increase in production to 3,792 MMcfe during the six months ended June 30, 2006 from 2,075 MMcfe during the period ended June 30, 2005. In addition to the increase in production, the average natural gas sales price increased during the six months ended June 30, 2006 as compared to the six months ended June 30, 2005.

Hedging Activities

During the six months ended June 30, 2006, we have effectively hedged 97% of our natural gas production, which resulted in revenues that were $9.2 million greater than we would have achieved at unhedged prices. During the six months ended June 30, 2005, we hedged approximately 100% of our natural gas production, which resulted in revenues that were $16.8 million less than we would have achieved at unhedged prices. Unrealized gain on derivatives in the amount of $28.0 million for the six months ended June 30, 2006 and unrealized loss on derivatives in the amount of $5.4 million for the six months ended June 30, 2005 were also recorded. Unrealized gains and losses result from natural gas price fluctuations as compared to the settlement price on the derivative.

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 per unit of production decreased from $1.59 per Mcfe in 2005 to $1.56 in 2006. Total operating expenses increased to $5.9 million for the six months ended June 30, 2006 from $3.3 million for the six months ended June 30, 2005, due to the increase in the number of wells as a result of the three acquisitions completed in both 2006 and in 2005, and the drilling of 84 and 110 wells during 2006 and 2005, respectively.

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 $16.4 million during the six months ended June 30, 2006, from $1.1 million compared to the six months ended June 30, 2005. General and administrative expenses are presented net of approximately $0.6 million and $0.5 million during the six months ended June 30, 2006 and 2005, respectively, which represents operating expense reimbursements from other working interest owners. The increase in general and administrative expenses was due to the recognition of unit-based compensation expense of $9.9 million and $2.0 million of bonuses paid in connection with our IPO during the six months ended June 30, 2006. In addition, our rapidly growing operations and increasing our staffing level to manage the additional wells acquired and drilled in 2006 and 2005 and to perform the functions associated with being a public company contributed to the increase.

Depreciation, depletion and amortization increased to $7.8 million for the six months ended June 30, 2006 from $2.6 million for the six months ended June 30, 2005, due to the increase in the number of wells as a result of the acquisitions completed and the drilling of wells during 2006 and 2005, as noted above. During the six months ended June 30, 2006 and 2005, the Company capitalized approximately $1.1 million and $0.4 million, respectively, of internal costs related to drilling.

Interest and financing income (expense) was a net expense of $5.3 million for the six months ended June 30, 2006 compared to a net expense of $2.3 million for the six months ended June 30, 2005. Our interest rate swaps were not specifically designated as hedges under SFAS 133, even though they reduce our exposure to changes in interest rates. Therefore, the mark-to-market of these instruments was recorded as a $0.7 million gain and a $16,000 gain for the six months ended June 30, 2006 and 2005, respectively. Further, these amounts represent non-cash charges. Cash payments for interest expense increased to approximately $5.0 million for the six months ended June 30, 2006, from $1.7 million for the six months ended June 30, 2005, primarily due to increased debt levels associated with the acquisitions completed and the drilling of wells during 2006 and 2005 as discussed above.

Income tax was a benefit of approximately $74,000 for the six months ended June 30, 2006, resulting from the recognition of deferred tax assets arising from net operating losses which are expected to be realized to the extent of deferred tax liabilities

arising from bases differences in property and equipment. Deferred tax assets exceeding deferred tax liabilities of $0.3 million have been offset by an increase in the valuation allowance during the six months ended June 30, 2006. Because we were structured as a limited liability company through May 31, 2005, no tax provision was recorded during the six months ended June 30, 2005.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires management to select and apply accounting policies that best provide the framework to report its results of operations and financial position. The selection and application of those policies requires management to make difficult subjective or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions.

As of June 30, 2006, there have been no significant changes with regard to the critical accounting policies disclosed in the Company s Annual Report on Form 10-K for the year ended December 31, 2005. The policies disclosed included the accounting for natural gas and oil properties, natural gas and oil reserve quantities, revenue recognition and derivative instruments. Effective January 1, 2006, the Company implemented SFAS 123R. See Note 9 in the Notes to Condensed Consolidated Financial Statements for a comprehensive discussion of the accounting for unit-based compensation expense, including a discussion of the assumptions used to estimate the fair market value of awards.

Liquidity and Capital Resources

Statements of Cash Flow

At June 30, 2006, we had cash and cash equivalents of $3.6 million compared to $11.0 million at December 31, 2005.

Cash provided by operating activities for the six months ended June 30, 2006 was $14.1 million, compared to cash used in operating activities of $10.0 million for the six months ended June 30, 2005. The increase in cash provided by operating activities was primarily due to the increase in net income, which was $32.2 million for the six months ended June 30, 2006, compared to a net loss of $17.7 million for the six months ended June 30, 2005. See Results of Operations above for detail about the increase in components of net income.

Cash used in investing activities was $65.8 million for the six months ended June 30, 2006, compared to $13.7 million for the six months ended June 30, 2005. The increase in cash used in investing activities was due to an increase in acquisition activity during the six months ended June 30, 2006 compared to the prior year. See Note 3 in the Notes to Consolidated Financial Statements.

Cash provided by financing activities was $44.3 million for the six months ended June 30, 2006, compared to $24.0 million for the six months ended June 30, 2005. In the first quarter of 2006, we completed our IPO of an aggregate of 12,450,000 units representing limited liability company interests at $21.00 per unit. The aggregate initial public offering price for the units issued was approximately $261.4 million. Net proceeds to the Company (after underwriting discounts of approximately $18.3 million and 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, 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 and approximately $2.0 million was used to pay bonuses to certain executive officers of the Company.

During the six months ended June 30, 2006, the Company received proceeds from borrowings on its credit facility of approximately $48.3 million, compared to proceeds of $101.4 million for the six months ended June 30, 2005.

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

In July 2006, the Company s Board of Directors declared a distribution of $0.40 per unit with respect to the second quarter of 2006. The distribution totaling approximately $11.2 million was paid on August 14, 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 of 2006. This is equivalent to a quarterly rate of $0.43 per unit.

Credit Facility

In August 2006, in connection with the acquisitions of the Blacksand Assets and the Kaiser Assets (see Note 3), the Company entered into an incremental senior secured revolving credit facility (the Credit Facility) with a maturity of August 2010, including an increase in the facility to $800.0 million and an increase in the borrowing base to $480.0 million. We also entered into a subordinated bridge loan (see Subordinated Bridge Loan below).

The terms under the incremental Credit Facility remain substantially the same as the previous terms. The borrowing base under the Credit Facility 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 Facility 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 Facility are guaranteed by all of our operating subsidiaries and may be guaranteed by any future subsidiaries.

At our election, interest on the Credit Facility 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 0.00% and 0.25% per annum. LIBOR

29

margins increase by 0.25% while the Subordinated Bridge Loan is outstanding. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

The Credit Facility 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 Facility also contains covenants that, among other things, require us to maintain specified financial ratios. The Company is in compliance with all financial and other covenants of its Credit Facility.

Subordinated Bridge Loan

In August 2006, in order to fund a portion of the acquisitions of the Blacksand Assets and the Kaiser Assets, we entered into a $250.0 million Subordinated Bridge Loan with a termination of August 1, 2007. Financial covenants under the Subordinated Bridge Loan are substantially similar to those under the Credit Facility. At our election, interest is determined by reference to LIBOR plus an applicable margin of 4.00% per annum; or a domestic bank rate plus an applicable margin of 2.50% per annum. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

Off-Balance Sheet Arrangements

The Company did not have any off-balance sheet arrangements as of June 30, 2006.

Commitments and Contractual Obligations

The Company has contractual obligations for long-term debt, operating leases and other long-term liabilities that were summarized in a table of contractual obligations in the 2005 Annual Report on Form 10-K. As of June 30, 2006, there have been no significant changes to the Company s contractual obligations from December 31, 2005.

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 swaps;
- Unit-based compensation expense;
- IPO cash bonuses; and
- Income tax provision.

The costs of canceling natural gas swaps before their original settlement date are 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. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. 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 June 30,		**Six months ended June 30,**	
	2006	**2005**	**2006**	**2005**
	(in thousands)			
Net income (loss)	$ 10,239	$ (5,276)	$ 32,216	$ (17,675)
Plus:				
Interest expense	2,696	2,279	5,335	2,259
Depreciation, depletion and amortization	4,116	1,406	7,816	2,587
Write-off of deferred financing fees	129	389	503	389
Loss on sale of assets	29	18	47	40
Loss from equity investment		7		17
Accretion of asset retirement obligation	61	32	119	57
Unrealized (gain) loss on natural gas derivatives	(7,055)	(1,197)	(27,978)	5,383
Realized (gain) loss on cancelled natural gas derivatives (1)				7,977
Unit-based compensation expense	4,196		9,876	

IPO bonuses			2,039	
Income tax benefit (2)	(193)		(74)	
Adjusted EBITDA	$ 14,218	$ (2,342)	$ 29,899	$ 1,034

(1) During the six months ended June 30, 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.

As noted above, Adjusted EBITDA is non-GAAP performance measure used by our management and is a quantitative measure used in the natural gas and oil industry. On our consolidated statements of cash flows, our net cash provided by operating activities for the six months ended June 30, 2006 was approximately $14.1 million and includes approximately $28.0 million unrealized gain on natural gas derivatives, $9.8 million unit-based compensation expense and $2.0 million of bonuses paid to certain executive officers in connection with our IPO. Our net cash used by operating activities for the six months ended June 30, 2005 was approximately $10.0 million and includes $5.4 million unrealized loss on natural gas derivatives and $8.0 million realized loss on cancelled natural gas derivatives.

New Accounting Standards

There have been no new accounting standards that materially affected the Company this period; however, see Note 9 in the Notes to Condensed Consolidated Financial Statements for a discussion of SFAS 123R.

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, forward-looking statements can be identified by terminology such as may, will, could, should, expect, plan, project, intend, anticipate, believe, estimate, predict, poten continue, the negative of such terms or other 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 Item 1A. Risk Factors and elsewhere in this Quarterly Report on 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.

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.

At June 30, 2006, the fair value of hedges that settle during the next twelve months was an asset of approximately $12.0 million and a liability of approximately $4.4 for a net asset of approximately $7.6 million, which we are owed from the counterparty. A 10% increase in the index natural gas price above the June 30, 2006 price for the next twelve months would result in a change of approximately $5.8 million for a net asset of approximately of $1.8 million; conversely, a 10% decrease in the index natural gas price would increase the asset by approximately $5.8 million.

Our derivatives as of June 30, 2006, for 2006 through 2009, are summarized in the table presented in Note 12 in the Notes to Condensed Consolidated Financial Statements.

The following table summarizes the crude oil positions we have entered into subsequent to June 30, 2006, in connection with our acquisition of the Blacksand Assets:

	August 1 December 31, 2006	**Year 2007**	**Year 2008**	**Year 2009**
Fixed Price Swaps:				
Hedged Volume (Bbls)	150,000	450,000	450,000	450,000
Average Price ($/Bbl)	$ 77.32	$ 76.06	$ 76.06	$ 76.06
Puts:				
Hedged Volume (Bbls)	36,000	200,000	200,000	200,000
Average Price ($/Bbl)	$ 75.00	$ 75.00	$ 75.00	$ 75.00
Total:				
Hedged Volume (Bbls)	186,000	650,000	650,000	650,000
Average Price ($/Bbl)	$ 76.87	$ 75.73	$ 75.73	$ 75.73

Interest Rate Risk

At June 30, 2006, we had debt outstanding of $193.0 million, which incurred interest at floating rates in accordance with our revolving credit facility. As of June 30, 2006, the one-month LIBOR was approximately 5.3%. A 1% increase in LIBOR as of June 30, 2006 would result in an estimated $1.9 million increase in annual interest expense.

In order to finance the acquisitions of the Blacksand Assets and Kaiser Assets in August 2006, the Company modified its revolving credit facility, including an increase in the facility to $800.0 million and an increase in the borrowing base to $480.0 million. In addition, the Company entered into a $250.0 million subordinated bridge loan. See Note 6 in the Notes to Condensed Consolidated Financial Statements.

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 an interest rate of 3.2% and 4.3%, respectively, while receiving a floating interest 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 an interest rate of 5.2% and 5.7%, respectively, while receiving a floating interest 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 an interest rate of 3.1% and 4.4%, respectively, while receiving a floating interest rate.

A 1% change in LIBOR as of June 30, 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 cash flow hedges under SFAS 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 of the Board of Directors, 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.

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 Rule 15d-15(e) under the Securities Exchange Act of 1934, as amended (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 June 30, 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 Form 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 second quarter of 2006, Company management has taken and is taking the following steps to strengthen internal control over financial reporting.

Remediation activities that we implemented during the three months ended June 30, 2006 are as follows:

1. We engaged outside consultants with extensive natural oil and gas financial reporting experience to augment our current accounting resources to assist with 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. In addition, we implemented certain review and monitoring controls over account reconciliations, and analysis and post closing procedures.

3. We developed and implemented a process for determining the effective accounting date for an oil and gas property acquisition and formalized procedures necessary to appropriately account for future acquisitions.

4. We implemented the use of disclosure checklists addressing the disclosure requirements under GAAP as well as the incremental financial and nonfinancial information required by SEC regulations.

Subsequent to June 30, 2006, we have hired experienced personnel with technical accounting, financial reporting and oil and gas experience.

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 compliance efforts under Section 404 of the Sarbanes-Oxley Act of 2002. 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. All 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 June 30, 2006, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, are described above under remediation activities.

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 below. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

Related to Our Business

We may not have sufficient cash flow from operations to pay the quarterly distribution at the current distribution level and future distributions to our unitholders may fluctuate from quarter to quarter.

We may not have sufficient cash flow from operations each quarter to pay the quarterly distribution at the current distribution level. Under the terms of our limited liability company agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses and the amount of any cash reserve amounts that our Board of Directors establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to our unitholders. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas and oil we produce;
- the price at which we are able to sell our natural gas and oil production;
- the level of our operating costs;
- the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon; and
- the level of our capital expenditures.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- our ability to make working capital borrowings under our credit facility to pay distributions;
- the costs of acquisitions, if any;
- fluctuations in our working capital needs;
- timing and collectibility of receivables;
- restrictions on distributions contained in our credit facility;
- prevailing economic conditions; and
- the amount of cash reserves established by our Board of Directors for the proper conduct of our business.

As a result of these factors, the amount of cash we distribute to our unitholders in any quarter may fluctuate significantly from quarter to quarter and may be less than the current distribution level.

We will be prohibited from borrowing under our credit facility to pay distributions to unitholders if the amount of borrowings outstanding under our credit facility reaches or exceeds 90% of the borrowing base, which is the amount of money available for borrowing, as determined semi-annually by our lenders in their sole discretion. The lenders will redetermine the borrowing base based on an engineering report with respect to our natural gas and oil reserves, which will take into account the prevailing natural gas and oil prices at such time. Any time our borrowings exceed 90% of the then-specified borrowing base, our ability to pay distributions to our unitholders in any such quarter is solely dependent on our ability to generate sufficient cash from our operations.

If we do not make acquisitions on economically acceptable terms, then our future growth and ability to increase distributions will be limited.

Our ability to grow and to increase distributions to our unitholders is partially dependent on our ability to make acquisitions that result in an increase in pro forma available cash per unit. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

In any such case, our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will increase pro forma available cash per unit, these acquisitions may nevertheless result in a decrease in pro forma available cash per unit.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about revenues and costs, including synergies;
- significant increases in our indebtedness and working capital requirements;
- an inability to integrate successfully or timely the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management s attention from other business concerns;
- increased demands on existing personnel; and
- customer or key employee losses at the acquired businesses.

The scope and cost of these risks may ultimately be materially greater than estimated at the time of the acquisition. Further, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely impact our future growth and our ability to increase distributions.

We have substantial indebtedness under our credit facility. Our credit facility has and our term loan have substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations and our ability to pay distributions to our unitholders.

We have substantial indebtedness under our credit facility, (which was converted into a new $800.0 million credit facility in August 2006) and our term loan. As of August 14, 2006, we had approximately $400.6 million outstanding under our credit facility (with additional borrowing capacity of approximately $79.4 million) and approximately $250.0 million outstanding under our subordinated bridge loan. As a result of our indebtedness, we will use a portion of our cash flow to pay interest and principal when due, which will reduce the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business. Our ability to access the capital markets to raise capital on favorable terms will be affected by our debt level and by adverse market conditions resulting from, among other things, general economic conditions, contingencies and uncertainties that are difficult to predict and impossible to control. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness.

We depend on our credit facility for future capital needs and to fund a portion of our distributions. The credit facility restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We also are required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under our credit facility could result in a default under our credit facility, which could cause all of our existing indebtedness to be immediately due and payable.

Availability under our credit facility is determined semi-annually at the discretion of the lenders and is based in part on natural gas and oil prices. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the credit facility. Any increase in the borrowing base requires the consent of all the lenders. If the required lenders do not agree on an increase, then the borrowing base will be the highest borrowing base acceptable to the lenders holding 66 % of the commitments. Outstanding borrowings in excess of the borrowing base must be repaid

38

immediately, or we must pledge other natural gas and oil properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the credit facility. Significant declines in our production or significant declines in realized natural gas or oil prices for prolonged periods and resulting decreases in our borrowing base may force us to reduce or suspend distributions to our unitholders.

Increases in interest rates could adversely affect our business, results of operations, cash flows from operations and financial condition.

In addition to our exposure to commodity prices, we have significant exposure to increases in interest rates. As of August 14, 2006, we had approximately $650.6 million of indebtedness outstanding under the credit facility and subordinated bridge loan, all of which is at variable interest rates, after giving effect to existing interest swap arrangements. Therefore, our business, results of operations, cash flows from operations could be adversely affected by significant increases in interest rates.

An increase in interest rates may cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our units. Any such reduction in demand for our units resulting from other more attractive investment opportunities may cause the trading price of our units to decline.

If commodity prices decline significantly for a prolonged period, our cash flow from operations will decline, and we may have to lower our distribution or may not be able to pay distributions at all.

Our revenue, profitability and cash flow depend upon the prices and demand for natural gas and oil. The natural gas and oil markets are very volatile and a drop in prices can significantly affect our financial results and impede our growth. Changes in natural gas and oil prices have a significant impact on the value of our reserves and on our cash flow. Prices for natural gas and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for natural gas and oil;
- the price and level of foreign imports;
- the level of consumer product demand;
- weather conditions;
- overall domestic and global economic conditions;
- political and economic conditions in natural gas and oil producing countries, including those in the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the impact of the U.S. dollar exchange rates on natural gas and oil prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity and capacity of natural gas and oil and pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

In the past, the prices of natural gas and oil have been extremely volatile, and we expect this volatility to continue. If commodity prices decline significantly for a prolonged period, our cash flow from operations will decline, and we may have to lower our distribution or may not be able to pay distributions at all.

Future price declines may result in a write-down of our asset carrying values.

Declines in natural gas and oil prices may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and gas properties for impairments. We are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and therefore require a write-down. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our credit facility, which in turn may adversely affect our ability to make cash distributions to our unitholders.

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our cash flow from operations and our ability to make distributions to our unitholders.

Producing natural gas and oil reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The overall rate of decline for our production will change if production from our existing wells declines in a different manner than we have estimated and can change when we drill additional wells, make acquisitions and under other circumstances. Thus, our future natural gas and oil reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our affect our cash flow from operations and our ability to make distributions to our unitholders.

Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

No one can measure underground accumulations of natural gas or oil in an exact way. Reserve engineering requires subjective estimates of underground accumulations of natural gas and oil and assumptions concerning future natural gas and oil prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Our independent petroleum engineers prepare estimates of our proved reserves. Over time, our internal engineers may make material changes to reserve estimates taking into account the results of actual drilling and production. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, we make certain assumptions regarding future natural gas and oil prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas or oil attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas and oil we ultimately recover being different from our reserve estimates. The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas and oil reserves. We base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the day of estimate. However, actual future net cash flows from our natural gas and oil properties also will be affected by factors such as:

- actual prices we receive for natural gas and oil;
- the amount and timing of actual production;
- supply of and demand for natural gas and oil; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Our development operations require substantial capital expenditures, which will reduce our cash available for distribution. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves.

The natural gas and oil industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, production and acquisition of natural gas and oil reserves. These expenditures will reduce our cash available for distribution. We intend to finance our future capital expenditures with cash flow from operations and our financing arrangements. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of natural gas and oil we are able to produce from existing wells;

- the prices at which we are able to sell our natural gas and oil; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower natural gas or oil prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Our credit facility restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our development operations, which in turn could lead to a possible decline in our reserves.

Our business depends on gathering and transportation facilities. Any limitation in the availability of those facilities would interfere with our ability to market the natural gas and oil we produce, and could reduce our cash available for distribution and adversely impact expected increases in natural gas and oil production from our drilling program.

Although we gather most of our current production, the marketability of our natural gas and oil production depends in part on the availability, proximity and capacity of gathering and pipeline systems. The amount of natural gas and oil that can be produced and sold is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, some of our wells are drilled in locations that are not serviced by gathering and transportation pipelines, or the gathering and transportation pipelines in the area may not have sufficient capacity to transport the additional production. As a result, we may not be able to sell the natural gas and oil production from these wells until the necessary gathering and transportation systems are constructed. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, would interfere with our ability to market the natural gas and oil we produce, and could reduce our cash available for distribution and adversely impact expected increases in natural gas and oil production from our drilling program.

We depend on certain key customers for sales of our natural gas and oil. To the extent these and other customers reduce the volumes of natural gas or oil they purchase from us, our revenues and cash available for distribution could decline.

For the year ended December 31, 2005, Dominion Resources, Inc., Cabot Oil & Gas Corporation, UGI Energy Services, Inc., Amerada Hess Corporation and Equitable Resources, Inc. accounted for approximately 48%, 14%, 10%, 7% and 6%, respectively, of our total volumes, or 85% in the aggregate. For the six months ended June 30, 2006, Dominion Resources, Inc., Equitable Gas Co. and Cabot Oil & Gas Corporation accounted for approximately 67%, 9% and 9%, respectively, of our total volumes, or 85% in the aggregate. To the extent these and other customers reduce the volumes of natural gas that they purchase from us, our revenues and cash available for distribution could decline.

Shortages of drilling rigs, pipe, equipment and crews could delay our operations and increase our drilling costs, which could impact our ability to generate sufficient cash flow from operations to pay quarterly distributions to our unitholders at the current distribution level.

Higher natural gas or oil prices generally increase the demand for drilling rigs, pipe, equipment and crews and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could impact our ability to generate sufficient cash flow from operations to pay quarterly distributions to our unitholders at the current distribution level.

Because we handle natural gas, oil and other petroleum products, we may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment.

The operations of our wells, gathering systems, turbines, pipelines and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example:

- the federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions;
- the federal Clean Water Act and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated bodies of water;
- the federal Resource Conservation and Recovery Act, and comparable state laws that impose requirements for the handling and disposal of waste from our facilities; and

41

Because we handle natural gas, oil and other petroleum products, we may incur significant costs and liabilities in th

- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as Superfund, and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes, including the RCRA, CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. For example, an accidental release from one of our wells or gathering pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover these costs from insurance. Please read Business - Operations - Environmental Matters and Regulation in our Annual Report on Form 10-K for the year ended December 31, 2005.

We may decide not to drill some of the prospects we have identified, and locations that we decide to drill may not yield natural gas or oil in commercially viable quantities.

Our prospective drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require additional seismic data processing and interpretation. Based on a variety of factors, including future natural gas and oil prices, the generation of additional seismic or geological information, the availability of drilling rigs and other factors, we may decide not to drill one or more of these prospects. As a result, we may not be able to increase or maintain our reserves or production, which in turn could have an adverse effect on our business, financial condition or results of operations.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomic if we drill dry holes or wells that are productive but do not produce enough natural gas or oil to be commercially viable after drilling, operating and other costs. If we drill future wells that we identify as dry holes, our drilling success rate would decline, which could have an adverse effect on our business, financial condition or results of operations.

Many of our leases are in areas that have been partially depleted or drained by offset wells.

Our key project areas are located in the most active drilling areas in the Appalachian Basin. As a result, many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of natural gas or oil in these areas.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, resulting in temporarily lower cash from operations, which may impact our ability to pay distributions.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of June 30, 2006, we had identified 1,037 drilling locations, of which 391 were proved undeveloped locations and 646 were other locations. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, natural gas and oil prices, costs and drilling results. In addition, Schlumberger Data and Consulting Services has not assigned any proved reserves to the 646 other drilling locations we have identified and scheduled for drilling and therefore there may exist greater uncertainty with respect to the success of drilling wells at these drilling locations. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce natural gas and oil from these

Many of our leases are in areas that have been partially depleted or drained by offset wells.

or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Drilling for and producing natural gas and oil are high risk activities with many uncertainties that could adversely affect our financial condition or results of operations and, as a result, our ability to pay distributions to our unitholders.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for natural gas and oil can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events;
- adverse weather conditions, particularly seasonal weather conditions in the spring;
- facility or equipment malfunctions;
- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- fires;
- blowouts, craterings and explosions; and
- uncontrollable flows of natural gas, oil or well fluids.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties. We ordinarily maintain insurance against certain losses and liabilities arising from our operations. However, it is impossible to insure against all operational risks in the course of our business. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Properties that we buy may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.

One of our growth strategies is to capitalize on opportunistic acquisitions of natural gas and oil reserves. However, our reviews of acquired properties are inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

Our hedging activities could result in financial losses or could reduce our income, which may adversely affect our ability to pay distributions to our unitholders.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of natural gas and oil, we currently and may in the future enter into hedging arrangements for a significant portion of our natural gas and oil production. If we experience a sustained material interruption in our production or if we are unable to perform our drilling activity as planned, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction of our liquidity. Under our credit facility, we are prohibited from hedging all of our production, and we therefore retain the risk of a price decrease on our unhedged volumes.

We depend on our Chairman, President and Chief Executive Officer who would be difficult to replace.

We depend on the performance of Michael C. Linn, our Chairman, President and Chief Executive Officer. We maintain no key person insurance for Mr. Linn. The loss of Mr. Linn could negatively impact our ability to execute our strategy and our results of operations.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results could be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002 by our initial compliance date of December 31, 2007. We identified a material weakness in our internal controls during the course of evaluating disclosure controls and procedures as of December 31, 2005. For additional information, please read Item 9A. Controls and Procedures in our Annual Report on Form 10-K for the year ended December 31, 2005.

Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet certain reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our units.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.

The natural gas and oil industry is intensely competitive, and we compete with companies that have greater resources than we have. Our ability to acquire additional properties and to discover reserves will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce natural gas and oil, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for natural gas and oil properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, these companies may have a greater ability to continue drilling activities during periods of low natural gas and oil prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon natural gas and oil wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which we operate includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of natural gas and oil we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to develop our properties.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, r

Additionally, the natural gas and oil regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our ability to pay distributions to our unitholders. For a description of the laws and regulations that affect us, please read Business - Operations - Environmental Matters and Regulation and Business - Operations - Other Regulation of the Natural Gas and Oil Industry in our Annual Report on Form 10-K for the year ended December 31, 2005.

We may face risks related to the recent restatement of our financial statements.

We restated our financial statements for the period from March 14, 2003 (inception) through December 31, 2003, for the year ended December 31, 2004 and certain financial statement line items for the nine months ended September 30, 2004 and 2005 primarily to correct certain accounting entries related to the acquisition of natural gas and oil properties. As a result of these changes, which primarily affect fiscal 2003 and 2004, revenues were reduced by $944,164 and $1,729,526, respectively, and net loss was increased by $353,305 and $83,018, respectively. Companies that restate their financial statements sometimes face litigation claims and/or SEC proceedings following such a restatement of financial results. Although we are unaware of any pending or threatened claims or proceedings relating to our restatement, if any claim or proceeding were to be commenced and successfully asserted against us, we could face monetary judgments, penalties or other sanctions which could adversely affect our financial condition and could cause the price of our units to decline.

Risks Related to Our Structure

Our management and Quantum Energy Partners own, in the aggregate, a controlling interest in us, with management and Quantum Energy Partners owning approximately 16.2% and 36.4%, respectively, of our units.

Our management and Quantum Energy Partners own or control an aggregate 52.6% of our outstanding units. Accordingly, management and Quantum Energy Partners, acting together, possess a controlling vote on substantially all matters submitted to a vote of the holders of our units. As long as management and Quantum Energy Partners in the aggregate beneficially own a controlling interest in us, they will have the ability to elect all members of our Board of Directors and to control our management and affairs. Our management and Quantum Energy Partners will be able to cause a change of control of our company. This concentration of ownership may have the effect of preventing or discouraging transactions involving an actual or a potential change of control of our company, regardless of whether a premium is offered over then-current market prices.

Each of management or Quantum Energy Partners, or both, may have conflicts of interest with us. Our limited liability company agreement limits the remedies available to our unitholders in the event unitholders have a claim relating to conflicts of interest.

Conflicts of interest may arise between our management or Quantum Energy Partners, and us and our unitholders. These potential conflicts may relate to the divergent interests of our management or Quantum Energy Partners. Situations in which the interests of our management or Quantum Energy Partners may differ from interests of our non-affiliated unitholders include, among others, the following situations:

- our limited liability company agreement gives our Board of Directors broad discretion in establishing cash reserves for the proper conduct of our business, which will affect the amount of cash available for distribution. For example, our management will use its reasonable discretion to establish and maintain cash reserves sufficient to fund our drilling program;

- our management team determines the timing and extent of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuances of additional membership interests and reserve adjustments, all of which will affect the amount of cash that we distribute to our unitholders; and

- Quantum Energy Partners and other affiliates of our directors are not prohibited from investing or engaging in other businesses or activities that compete with us.

We may issue additional units without unitholder approval, which would dilute existing ownership interests.

We may issue an unlimited number of limited liability company interests of any type, including units, without the approval of our unitholders.

We may issue additional units without unitholder approval, which would dilute existing ownership interests.

The issuance of additional units or other equity securities may have the following effects:

- an individual unitholder s proportionate ownership interest in us may decrease;
- the amount of cash distributed on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be reduced; and
- the market price of the units may decline.

The market price of our units could be volatile for a number of factors, many of which are beyond our control.

The market price of our units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in securities analysts recommendations and their estimates of our financial performance;
- the public s reaction to our press releases, announcements and our filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of natural gas and oil companies and securities of publicly-traded limited partnerships and limited liability companies;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other natural gas and oil companies;
- variations in the amount of our quarterly cash distributions;
- future issuances and sales of our units; and
- changes in general conditions in the U.S. economy, financial markets or the natural gas and oil industry.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our units.

Quantum Energy Partners may sell units in the future, which could reduce the market price of our outstanding units.

As of August 14, 2006, Quantum Energy Partners controlled an aggregate of 10,144,585 units. In addition, we have agreed, upon demand by Quantum, to register for sale units held by Quantum Energy Partners, certain non-affiliated investors and certain members of our management. These registration rights allow Quantum Energy Partners to request registration of their units and to include any of those units in a registration of other securities by us. If Quantum Energy Partners were to sell a substantial portion of their units, then the market price of our outstanding units may decline.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our limited liability company agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements.

The value of our units may decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may have difficulty issuing more equity to recapitalize we may be unable to issue more equity to recapitalize.

46

Quantum Energy Partners may sell units in the future, which could reduce the market price of our outstanding units

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to entity-level taxation for state tax purposes, taxes paid, if any, would reduce the amount of cash available for distribution.

The anticipated after-tax benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matters.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rates, currently at a maximum rate of 35%, and would likely pay state income tax at varying rates. Distributions to unitholders would generally be taxed as corporate dividends, and no income, gain, loss, deduction or credit would flow through to unitholders. Because a tax may be imposed on us as a corporation, our cash available for distribution to our unitholders could be reduced. Therefore, our treatment as a corporation could result in a material reduction in the anticipated cash flow and after-tax return to our unitholders and therefore result in a substantial reduction in the value of our units.

Current law or our business may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships and limited liability companies to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to unitholders may be reduced.

Our unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us.

Our unitholders are required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our units, and the costs of any contest will reduce cash available for distribution.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter that affects us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and a court may disagree with some or all of those positions. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

We will treat each purchaser of our units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

Because we cannot match transferors and transferees of units, we will adopt depreciation and amortization positions that may not conform with all aspects of existing U.S. Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of units and could have a negative impact on the value of our units or result in audits of and adjustments to our unitholders tax returns.

Our unitholders may be subject to state and local taxes and return filing requirements.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not reside in any of those jurisdictions. Our unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently do business and own assets in West Virginia, Pennsylvania, New York, Virginia, California and

Oklahoma. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all United States federal, foreign, state and local tax returns that may be required of such unitholder. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in the units.

Tax gain or loss on the disposition of our units could be more or less than expected because prior distributions in excess of allocations of income will decrease the tax basis of the units.

As units are sold, our unitholders will recognize gain or loss equal to the difference between the amount realized and the tax basis in those units. Prior distributions to unitholders in excess of the total net taxable income they were allocated for a unit, which decreased our unitholders tax basis in that unit, will, in effect, become taxable income to them if the unit is sold at a price greater than their tax basis in that unit, even if the price received is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to the unitholder

We will be considered to have terminated for tax purposes due to a sale or exchange of 50% or more of our interests within a twelve-month period.

We will be considered to have terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. A constructive termination results in the closing of our taxable year for all unitholders and in the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. A constructive termination occurring on a date other than December 31 will result in us filing two tax returns (and unitholders receiving two Schedule K-ls) for one fiscal year and the cost of the preparation of these returns will be borne by all of our unitholders.

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

Exhibit Number	**Description**
2.1	Purchase and Sale Agreement by and among Linn Energy, LLC and Blacksand Energy, LLC, dated July 19, 2006 (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Linn Energy, LLC on July 25, 2006 (the July 25, 2006 Form 8-K))
2.2	Purchase and Sale Agreement between Kaiser-Francis Oil Company and Linn Energy Mid-Continent Holdings, LLC, dated July 21, 2006 (incorporated herein by reference to Exhibit 2.2 to the July 25, 2006 Form 8-K)
3.1	Certificate of Formation of Linn Energy Holdings, LLC (now Linn Energy, LLC) (incorporated herein by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (File No. 333-125501) filed by Linn Energy, LLC on June 30, 2005) (the Form S-1)
3.2	Certificate of Amendment to Certificate of Formation of Linn Energy Holdings, LLC (now Linn Energy, LLC) (incorporated herein by reference to Exhibit 3.2 to the Form S-1)
3.3	Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Linn Energy, LLC on January 19, 2006)
4.1	Form of specimen unit certificate for the units of Linn Energy, LLC (incorporated herein by reference to Exhibit 4.1 to the Annual Report on Form 10-K filed by Linn Energy, LLC on May 31, 2006)
10.1*	Form of Unit Option Agreement pursuant to the Linn Energy, LLC Long-Term Inceptive 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	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)
10.8*	Separation and General Release, dated effective as of June 5, 2006 between Linn Energy, LLC and its subsidiaries and Donald T. Robinson (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Linn Energy, LLC on June 6, 2006)
10.9*	Employment Agreement, dated effective as of July 7, 2006 between Linn Operating, Inc. and Lisa D. Anderson (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Linn Energy, LLC on July 13, 2006)
10.10	Second Amended and Restated Credit Agreement dated as of August 1, 2006 among Linn Energy, LLC as Borrower, BNP Paribas, as Administrative Agent, Royal Bank of Canada, as Syndication Agent, Societe Generale, Comerica Bank and Citibank Texas, N.A. as Co-Documentation Agents and the Lenders Party thereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Linn Energy, LLC on August 7, 2006 (the August 7, 2006 Form 8-K))
10.11	Second Lien Bridge Loan Agreement dated as of August 1, 2006 among Linn Energy, LLC as Borrower, BNP Paribas, as Administrative Agent, Royal Bank of Canada, as Syndication Agent, Societe Generale, Citicorp North America, Inc. and McDonald Investments Inc., as Co-Documentation Agents and the Lenders Party thereto (incorporated herein by reference to Exhibit 10.2 to the August 7, 2006 Form 8-K)
10.12	Second Amended and Restated Guaranty and Pledge Agreement dated as of August 1, 2006 made by Linn Energy, LLC and each of the other Obligors in favor of BNP Paribas, as Administrative Agent (incorporated herein by reference to Exhibit 10.3 to the August 7, 2006 Form 8-K)

We will be considered to have terminated for tax purposes due to a sale or exchange of 50% or more of our interes

10.13	Second Lien Guaranty and Pledge Agreement dated as of August 1, 2006 made by Linn Energy, LLC and each of the other Obligors in favor of BNP Paribas, as Administrative Agent (incorporated herein by reference to Exhibit 10.4 to the August 7, 2006 Form 8-K)
10.14*	Form of Phantom Unit Grant Agreement for Independent Directors pursuant to the Linn Energy, LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Linn Energy, LLC on August 9, 2006)
31.1**	Rule 13a-14(a)/15d-14(a) Certification of Michael C. Linn, Chairman, President and Chief Executive Officer of Linn Energy, LLC (filed herewith)
31.2**	Rule 13a-14(a)/15d-14(a) Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC (filed herewith)
32.1**	Section 1350 Certification of Michael C. Linn, Chairman, President and Chief Executive Officer of Linn Energy, LLC (filed herewith)
32.2**	Section 1350 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC (filed herewith)

** Filed herewith.

* Management Contract, Compensatory Plan or Arrangement required to be filed as an exhibit hereto pursuant to Item 601 of Regulation S-K.

SIGNATURE

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.

LINN ENERGY, LLC
(Registrant)

Date: August 15, 2006

/s/ Lisa D. Anderson
Lisa D. Anderson
Senior Vice President and Chief Accounting Officer
(As Duly Authorized Officer and Chief Accounting Officer)