LINN ENERGY, LLC
Form 10-Q
November 14, 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 September 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 November 1, 2006, there were 33,417,187 units outstanding.

As of November 1, 2006, there were 9,185,965 class B units outstanding.

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GLOSSARY OF TERMS

As commonly used in the oil and gas 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 United States 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.

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 an oil or gas 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 oil and gas 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 oil and gas 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 oil and/or gas 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 oil and/or gas 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 oil and gas regardless of whether such acreage contains proved reserves.

Unproved reserves. Lease acreage on which wells have not been drilled and where it is either probable or possible that the acreage contains 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

	September 30, 2006 (Unaudited) (in thousands)	December 31, 2005
Assets		
Current assets:		
Cash and cash equivalents	$ 1,762	$ 11,041
Receivables:		
Oil and gas, net of allowance for doubtful accounts of $100 as of September 30, 2006 and December 31, 2005	20,609	17,103
Other	233	650
Fair value of interest rate swaps	132	202
Inventory	560	68
Current portion of oil and gas derivatives	30,404	1,601
Other current assets	1,161	4,068
Total current assets	54,861	34,733
Oil and gas properties and related equipment (successful efforts method)	754,935	250,000
Less accumulated depreciation, depletion, and amortization	23,589	10,707
	731,346	239,293
Property and equipment, net	11,297	2,525
Other assets:		
Long-term portion of oil and gas derivatives	43,398	2,795
Deferred tax assets, net	307	
Operating bonds	198	198
Intangible assets	2,208	
	46,111	2,993
Total assets	$ 843,615	$ 279,544

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

	September 30, 2006 (Unaudited) (in thousands)	December 31, 2005
Liabilities and Unitholders Capital (Deficit)		
Current liabilities:		
Current portion of long-term notes payable	$ 675	$ 113
Subordinated term loan		59,501
Accounts payable and accrued expenses	6,325	5,572
Current portion of oil and gas derivatives	573	12,094
Revenue distribution	981	6,082
Accrued interest payable	3,732	1,448
Gas purchases payable	923	1,208
Other current liabilities	40	40
Total current liabilities	13,249	86,058
Long-term liabilities:		
Long-term portion of notes payable	2,353	695
Credit facility	404,257	206,119
Subordinated bridge loan	247,275	
Long-term portion of interest rate swaps	492	663
Asset retirement obligation	8,434	5,443
Long-term portion of oil and gas derivatives	10,273	27,139
Other long-term liabilities	474	258
Total long-term liabilities	673,558	240,317
Total liabilities	686,807	326,375
Unitholders capital (deficit):		
27,882,500 units issued and outstanding at September 30, 2006	134,390	16,024
Accumulated income (loss)	22,418	(62,855)
	156,808	(46,831)
Total liabilities and unitholders capital (deficit)	$ 843,615	$ 279,544

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

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LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three months ended September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
	(in thousands, except per unit amounts)			
Revenues:				
Oil and gas sales	$ 23,506	$ 10,407	$ 53,410	$ 24,408
Realized gain (loss) on oil and gas derivatives	8,198	(29,058)	17,361	(45,822)
Unrealized gain (loss) on oil and gas derivatives	49,198	(21,405)	77,176	(26,788)
Natural gas marketing income	1,090	1,618	3,654	3,087
Other income	265	20	758	158
	82,257	(38,418)	152,359	(44,957)
Expenses:				
Operating expenses	4,845	1,386	10,772	4,691
Natural gas marketing expense	954	1,768	3,126	3,162
General and administrative expenses	6,536	1,197	22,934	2,345
Depreciation, depletion and amortization	5,654	1,448	13,470	4,035
	17,989	5,799	50,302	14,233
	64,268	(44,217)	102,057	(59,190)
Other income and (expenses):				
Interest income	107	13	345	16
Interest and financing expenses	(11,204)	(998)	(16,539)	(3,282)
Write-off of deferred financing fees and other losses	(114)	(3)	(664)	(424)
	(11,211)	(988)	(16,858)	(3,690)
Income (loss) before income taxes	53,057	(45,205)	85,199	(62,880)
Income tax benefit (provision)		(385)	74	(385)
Net income (loss)	$ 53,057	$ (45,590)	$ 85,273	$ (63,265)
Net income (loss) per unit - basic	$ 1.92	$ (2.22)	$ 3.14	$ (3.08)
Net income (loss) per unit - diluted	$ 1.89	$ (2.22)	$ 3.12	$ (3.08)
Weighted average units outstanding - basic	27,584	20,518	27,118	20,518
Weighted average units outstanding - diluted	28,044	20,518	27,341	20,518
Distributions declared per unit	$ 0.40	$	$ 0.72	$

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENT OF UNITHOLDERS CAPITAL (DEFICIT)

(Unaudited)

	Unitholders Capital	Accumulated Income (Loss)	Treasury Units (at Cost)	Total Unitholders Capital (Deficit)
	(in thousands)			
Balance as of December 31, 2005	$ 16,024	$ (62,855)	$	$ (46,831)
Sale of units, net of offering expense of $4,339	225,139		13,671	238,810
Redemption of member units			(114,449)	(114,449)
Cancellation of member units	(100,778)		100,778	
Distribution to members	(19,859)			(19,859)
Unit-based compensation expense	13,864			13,864
Net income		85,273		85,273
Balance as of September 30, 2006	$ 134,390	$ 22,418	$	$ 156,808

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

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LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine months ended September 30,	
	2006	**2005**
	(in thousands)	
Cash flow from operating activities:		
Net income (loss)	$ 85,273	$ (63,265)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	13,470	4,035
Amortization and write-off of deferred financing fees and other losses	1,650	573
Accretion of asset retirement obligation	180	124
Unrealized (gain) loss on oil and gas and interest rate derivatives	(77,276)	26,013
Unit-based compensation	13,864	
Deferred income tax	(307)	
Changes in assets and liabilities, net of effects of acquisitions:		
Increase in accounts receivable	(3,089)	(3,110)
(Increase) decrease in inventory and other assets	3,542	(71)
Increase (decrease) in accounts payable and accrued expenses	(5,821)	127
Increase (decrease) in oil and gas and interest rate derivatives	(20,616)	402
(Decrease) in revenue distribution	(5,101)	(692)
Increase in accrued interest payable	2,284	288
Increase (decrease) in gas purchases payable	(285)	623
Increase in other liabilities	216	572
Net cash provided by (used in) operating activities	7,984	(34,381)
Cash flow from investing activities:		
Acquisition and development of oil and gas properties	(502,847)	(27,540)
Purchases of property and equipment	(6,259)	(874)
Other investing activities	21	(30)
Net cash (used in) investing activities	(509,085)	(28,444)
Cash flow from financing activities:		
Proceeds from sale of units	243,149	
Redemption of member units	(114,449)	
Proceeds from notes payable		5,262
Principal payments on notes payable	(597)	(5,058)
Proceeds from credit facility	261,303	142,000
Principal payments on credit facility	(62,000)	(75,605)
Proceeds from subordinated bridge loan	250,000	
Principal payments on subordinated term loan	(60,000)	
Distribution to members	(19,859)	
Deferred offering costs	(844)	(2,145)
Deferred financing fees	(4,881)	(840)
Net cash provided by financing activities	491,822	63,614
Net increase (decrease) in cash	(9,279)	789
Cash and cash equivalents:		

Beginning	11,041		2,188
Ending	$ 1,762		$ 2,977

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

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LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - Continued

(Unaudited)

	Nine months ended September 30, 2006	2005
	(in thousands)	
Supplemental disclosure of cash flow information:		
Cash payments for interest	$ 13,603	$ 3,596
Supplemental disclosure of non cash investing and financing activities:		
Increase in oil and gas properties and related asset retirement obligation due to acquisitions and new drilling	$ 2,652	$ 417
Acquisition of vehicles and equipment through issuance of notes payable	$ 2,648	$ 294
In connection with the purchase of Blacksand and the Kaiser-Francis Assets, liabilities were assumed as follows:		
Fair value of assets acquired	$ 426,957	
Cash paid	(424,236)	
Liabilities assumed	$ 2,721	

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

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

(1) Basis of Presentation

The condensed consolidated financial statements at September 30, 2006, and for the three and nine months ended September 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 oil and gas company focused on the development and acquisition of long-lived properties in the United States. As of September 30, 2006, Linn s wholly owned subsidiaries included Linn Energy Holdings, LLC, Linn Energy Mid-Continent Holdings, LLC, Linn Energy Western Holdings, LLC, Linn Operating, Inc., Linn Western Processing, LLC, Penn West Pipeline, LLC, Mid Atlantic Well Service, Inc., Linn Western Operating, Inc., and Linn Mid-Continent Operating, Inc.

(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) Oil and gas Properties

The Company accounts for oil and gas 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 oil and gas 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 oil and gas properties relating to unsuccessful exploratory wells are charged to expense as incurred.

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

Oil and gas 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 oil and gas 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 nine months ended September 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 nine months ended September 30, 2006 or 2005.

(e) Oil and Gas Reserve Quantities

The Company s estimates of proved reserves are based on the quantities of oil and gas 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 crude 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 September 30, 2006 and December 31, 2005, respectively. At September 30, 2006, deferred tax assets of approximately $0.3 million, net of a valuation allowance of $1.8 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 crude oil and natural gas production by reducing its exposure to price fluctuations. As of September 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) *Intangible Assets*

Under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS 142), the Company amortizes the intangible asset acquired as part of the purchase of Blacksand (see Note 3) over the period in which the asset is expected to contribute to future cash flows, which is consistent with the life of the underlying oil and gas reserves. The amortized intangible asset is evaluated for impairment in accordance with SFAS No. 144 *Accounting for the Impairment or Disposal of Long-Lived Assets* when events and circumstances indicate that the asset might be impaired.

(i) *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.

In accordance with SFAS No. 128, *Earnings per Share,* dual presentation of basic and diluted earnings per share has been presented in the Condensed Consolidated Statements of Earnings. The following reconciliation illustrates the impact on the share amounts of potential common shares and the earnings per share amounts:

	Three months ended September 30,		Nine months ended September 30,	
	2006	**2005**	**2006**	**2005**
	(in thousands, except per unit amounts)			
Basic:				
Net income (loss)	$ 53,057	$ (45,590)	$ 85,273	$ (63,265)
Average number of units outstanding	27,584	20,518	27,118	20,518
Net income (loss) per unit (basic)	$ 1.92	$ (2.22)	$ 3.14	$ (3.08)
Diluted:				
Net income (loss)	$ 53,057	$ (45,590)	$ 85,273	$ (63,265)
Average number of units outstanding	27,584	20,518	27,118	20,518
Dilutive effect of unit equivalents (a)	460		223	
Equivalent units outstanding	28,044	20,518	27,341	20,518
Net income (loss) per unit (diluted)	$ 1.89	$ (2.22)	$ 3.12	$ (3.08)

(a) Excludes the effect of average anti-dilutive common stock equivalents related to out-of-the-money options of 16,055 and 61,313 for the three and nine months ended September 30, 2006, respectively.

(j) *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 oil and gas reserves, future cash flows from oil and gas properties, depreciation, depletion and amortization, asset retirement obligations, the fair value of derivatives and unit awards.

(k) Revenue Recognition

Sales of oil and gas are recognized when oil or 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. Oil and 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 crude oil and natural gas, and prevailing supply and demand conditions, so that the price of the crude oil and natural gas fluctuate to remain competitive with other available oil and gas supplies. As a result, the Company s revenues from the sale of oil and gas will suffer if market prices decline and benefit if they increase. The Company believes that the pricing provisions of its oil and 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 September 30, 2006 or December 31, 2005.

Natural gas marketing is recorded on the gross accounting method because Penn West Pipeline, LLC, 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 nine months ended September 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 generates electricity with excess gas, which it uses to serve certain of its operating facilities in California. Any excess electricity is sold to the wholesale power market and the revenue is recorded on the accrual basis. This revenue is included in other income on the condensed consolidated statement of operations.

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 nine months ended September 30, 2006, the operating fees netted against general and administrative expense were approximately $0.2 million and $0.9 million, respectively. For the three and nine months ended September 30, 2005, the operating fees netted against general and administrative expense were approximately $0.3 million and $0.8 million, respectively.

(l) Unit-Based Compensation

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

(m) 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 implementation 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.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS 157), which provides guidance for using fair value to measure assets and liabilities. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value and clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk, not just the company s mark-to-model value. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company is currently evaluating the effect that the implementation of SFAS 157 will have on its results of operations and financial condition, but does not expect it will have a material impact.

In September 2006, the FASB issued Staff Position No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities,* which prohibits companies from accruing as a liability in annual and interim periods the future costs of periodic major overhauls and maintenance of plant and equipment (the accrue-in-advance method). Other previously acceptable methods of accounting for planned major overhauls and maintenance (the direct expense, built-in overhaul and deferral methods) will continue to be permitted. The new requirements apply to entities in all industries for fiscal years beginning after December 15, 2006, and must be retrospectively applied. We do not expect that adoption of this FASB Staff Position will have a material impact on our results of operations or financial position.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108 (SAB 108). SAB 108 expresses the SEC staff s views regarding the process of quantifying financial statement misstatements. The SEC staff believes registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. The SEC staff will not object if a registrant records a one-time cumulative effect adjustment to correct errors existing in prior years that previously had been considered immaterial, quantitatively and qualitatively, based on appropriate use of the registrant s approach. SAB 108 describes the circumstances where this would be appropriate as well as required disclosures to investors. SAB 108 is effective for fiscal years ending on or after November 15, 2006. We are currently assessing the impact of adoption of SAB 108 on our financial statements but do not expect that adoption will have a material effect on our results of operations or financial position.

(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. 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 the third quarter of 2006, the Company acquired certain affiliated entities of Blacksand Energy, LLC (Blacksand), located in the Los Angeles Basin, for an aggregate purchase price, including estimated transaction costs and assumed liabilities, of approximately $300.7 million and certain Mid-Continent assets of Kaiser-Francis Oil Company (Kaiser-Francis Assets) located in Oklahoma for an aggregate purchase price, including estimated transaction costs and assumed liabilities, of approximately $126.3 million, in both cases subject to customary post-closing adjustments.

The acquisition of Blacksand was completed on August 1, 2006. The acquisition of the Kaiser-Francis Assets was completed on August 14, 2006, effective September 1, 2006. The results of operations of Blacksand and the Kaiser-Francis Assets are included in the consolidated results of the Company effective August 1, 2006 and September 1, 2006, respectively.

The acquisitions of the Kaiser-Francis Assets and Blacksand 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).

The following table presents the preliminary purchase prices as of the respective acquisition dates:

	Blacksand		Kaiser Francis Assets		Total	
	(in thousands)					
Cash	$	298,113	$	125,000	$	423,113
Estimated transaction costs	221		902		1,123	
Total preliminary purchase price	298,334		125,902		424,236	
Liabilities assumed	2,373		348		2,721	
Total purchase price plus liabilities	$	300,707	$	126,250	$	426,957

The assumed liabilities include asset retirement obligations of approximately $2.3 million for Blacksand and $0.3 million for the Kaiser-Francis Assets.

The following table presents, as of the respective acquisition dates, preliminary allocations of the purchase prices based on preliminary estimates of fair value:

	Blacksand		Kaiser-Francis Assets		Total	
	(in thousands)					
Field inventory	$	284	$		$	284
Oil and gas properties	297,659		126,250		423,909	
Vehicles and buildings	556				556	
Intangible asset	2,208				2,208	
	$	300,707	$	126,250	$	426,957

The preliminary purchase price allocations are based on preliminary independent appraisals, discounted cash flows, quoted market prices and estimates by management. The purchase price allocations will be completed within one year of the acquisition dates.

As part of the overall valuation of Blacksand, Linn has preliminarily determined that it acquired an intangible asset associated with a contract purchased as part of the acquisition. The contract is with a real estate developer under which the developer is obligated to make certain improvements in the acquired property. The intangible asset acquired is anticipated to have a life consistent with the underlying oil and gas reserves, and therefore, will be amortized on a straight-line basis over the life of the oil and gas reserves, in accordance with the provisions of SFAS No. 142.

The following unaudited pro forma financial information presents a summary of Linn s consolidated results of operations for the three and nine months ended September 30, 2006 and 2005, assuming the acquisitions of Blacksand and the Kaiser-Francis Assets had been completed as of January 1, 2005, including adjustments, which are based upon preliminary estimates, to reflect the allocation of the purchase prices to the acquired net assets. The pro forma financial information is not necessarily indicative of the results of operations if the acquisitions had been effective as of these dates.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Oil and gas sales	$ 29,405	$ 26,428	$ 84,231	$ 55,317
Total revenues	88,319	(21,845)	216,987	(12,166)
Total operating expenses	22,079	13,111	69,189	34,002
Net income (loss)	52,063	(46,099)	110,252	(79,553)
Net income (loss) per unit:				
Basic	$ 1.89	$ (2.25)	$ 4.07	$ (3.88)
Diluted	$ 1.86	$ (2.25)	$ 4.03	$ (3.88)

The pro forma results of operations for the nine months ended September 30, 2006 includes a Blacksand historical gain on property sale of $32.7 million. Under SEC Regulation S-X, this gain may not be excluded from the condensed combined pro forma financial statements. Had this gain been excluded, pro forma net income for the nine months ended September 30, 2006 would have been reduced by the gain recorded.

(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 $18.3 million and offering expenses of $4.3 million, of $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, $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) Oil and Gas Properties

	September 30, 2006	December 31, 2005
	(in thousands)	
Unproved properties	$ 1,932	$
Proved properties:		
Leasehold, equipment and drilling	733,161	244,420
Gas and compression plant	12,511	
Pipelines	7,331	5,580
	754,935	250,000
Less accumulated depletion, depreciation and amortization	(23,589)	(10,707)
	$ 731,346	$ 239,293

(6) Debt

Credit Facility

In August 2006, in connection with the acquisitions of Blacksand and the Kaiser-Francis Assets (see Note 3), the Company entered into an $800.0 million amended and restated senior secured revolving credit facility with a maturity of August 2010, and a borrowing base of $480.0 million (Credit Facility). 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 oil and gas prices at such time. Our obligations under the Credit Facility are secured by mortgages on our oil and gas properties as well as a pledge of all ownership interests in our

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operating subsidiaries. We are required to maintain the mortgages on properties representing at least 80% of our oil and gas 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 increased by 0.25% during the term of the Subordinated Bridge Loan, which was repaid in October 2006 (see Note 14). 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.

As of September 30, 2006 and December 31, 2005, the Credit Facility consisted of the following:

	September 30, 2006	December 31, 2005
	(in thousands)	
Outstanding balance	$ 406,000	$ 207,000
Less deferred financing fees, net of amortization of $710 and $160	(1,743)	(881)
	$ 404,257	$ 206,119

At September 30, 2006, the Company also had $4.0 million outstanding letters of credit, which reduce its borrowing availability under the Credit Facility.

Total accrued interest on the Credit Facility was approximately $2.0 million at September 30, 2006. Total accrued interest on the prior credit facility was approximately $1.1 million at December 31, 2005. The Company repaid $53.3 million of borrowings under its Credit Facility in October 2006 (see Note 14).

Subordinated Bridge Loan

In August 2006, in order to fund a portion of the acquisitions of Blacksand and the Kaiser-Francis 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.

As of September 30, 2006, the Subordinated Bridge Loan consisted of the following:

	September 30, 2006
	(in thousands)
Outstanding balance	$ 250,000
Less deferred financing fees, net of amortization of $545	(2,725)
	$ 247,275

Total accrued interest on the Subordinated Bridge Loan was approximately $1.7 million at September 30, 2006.

The Subordinated Bridge Loan is classified as long-term debt at September 30, 2006, as the proceeds from the private placement of class B units in October 2006 (see Note 14) were used to repay the entire amount outstanding.

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Subordinated Term Loan

During 2005, the Company had 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 oil and gas properties from Exploration Partners. The outstanding balance was paid in full in January 2006 with proceeds from our IPO. Total accrued interest on this loan was approximately $0.4 million at December 31, 2005.

(7) Long-term Notes Payable

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

	September 30, 2006	December 31, 2005
	(in thousands)	
Note payable to a bank with an interest rate of 6.14%, payable in monthly installments of approximately $3, including interest, through September 2024. The note is secured by an office building	$ 378	$ 387
Various notes for the purchase of vehicles and equipment, payable in monthly installments totaling approximately $72 and $11, as of September 30, 2006 and December 31, 2005, respectively, including interest. The interest rates range from 3.9%-8.87%. The notes are secured by the vehicles and equipment purchased and expire at various dates from 2008 through 2011.	2,650	421
	3,028	808
Less current portion	(675)	(113)
	$ 2,353	$ 695

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

	(in thousands)
2006	$ 110
2007	758
2008	759
2009	473
2010	432
2011	191
Thereafter	305
	$ 3,028

(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 oil and gas 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.

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A majority of the Company s largest customers are oil and gas producers and suppliers. For the three and nine months ended September 30, 2006, the Company s two largest customers represented approximately 48% and 26%, and 60% and 10%, respectively, of the Company s sales. The Company s two largest customers represented approximately 60% and 18%, and 59% and 18%, of the Company s sales for the three and nine months ended September 30, 2005, respectively.

At September 30, 2006, two customers trade accounts receivable from oil and gas sales accounted for more than 10% of the Company s total trade accounts receivable. At September 30, 2006, trade accounts receivable from these customers represented approximately 50%, and 21% of the Company s receivables. At December 31, 2005, two customers trade accounts receivable from oil and 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.

The 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 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 September 30, 2006, approximately 1.4 million units were issuable under the Plan pursuant to outstanding award or other agreements and an additional 2.5 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 nine months ended September 30, 2006, we recorded unit-based compensation expense of approximately $4.2 million and $14.1 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 nine months ended September 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 September 30, 2006, and changes during the nine months ended September 30, 2006, is presented below:

	Number of Non-vested Units		**Weighted Average Grant-Date Fair Value**	
Non-vested units at December 31, 2005			$	
Granted	1,039,145		21.22	
Vested	(114,455	)	21.00	
Forfeited				
Non-vested units at September 30, 2006	924,690		$	21.24

As of September 30, 2006, there was approximately $8.5 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.

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Changes in Unit Options and Unit Options Outstanding

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

	Number of Units Underlying Options	Weighted Average Exercise Price Per Unit	Weighted Average Grant Date Fair Value	Weighted Average Contractual Life in Years
Outstanding at December 31, 2005		$	$	
Granted	588,584	20.58	3.02	10.00
Exercised				
Forfeited	(87,084)	20.37	2.61	10.00
Outstanding at September 30, 2006	501,500	$ 20.62	$ 3.09	10.00
Exercisable at September 30, 2006	30,000	$ 20.18	$ 2.52	10.00

As of September 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 September 30, 2006 have an aggregate intrinsic value of approximately $76,000 and all outstanding unit options have an aggregate intrinsic value of approximately $975,000. No options expired during the period.

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%-8.50	%
Expected term (in years)		5.00
Risk free rate	4.31%-5.04	%
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:

	September 30, 2006 (in thousands)	December 31, 2005
Land	$ 308	$ 203
Buildings and leasehold improvements	2,220	608
Vehicles	6,292	1,317
Drilling equipment	1,933	
Furniture and equipment	1,567	888
	12,320	3,016
Less: accumulated depreciation	(1,023)	(491)
	$ 11,297	$ 2,525

Depreciation expense for the three and nine months ended September 30, 2006 was approximately $219,000 and $573,000, respectively. Depreciation expense for the three and nine months ended September 30, 2005 was approximately $93,000 and $204,000 respectively.

(11) Commitments and Contingencies

The Company would be exposed to oil and gas price fluctuations on underlying sale contracts should the counterparties to the Company s derivative instruments or the counterparties to the Company s oil and gas marketing contracts not perform. Such nonperformance is not anticipated. There were no counterparty default losses during the three and nine months ended September 30, 2006 or 2005.

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

(12) Oil and Gas Derivatives

The Company sells oil and 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 crude oil and natural gas. The Company enters into derivative instruments such as swap contracts and put options to hedge a portion of its forecasted oil and gas sales.

Settled derivatives on gas production for the three and nine months ended September 30, 2006 included a volume of 2,029 MMBtu and 6,083 MMBtu at an average price of $9.23 and $9.23, 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 next production month. Settled derivatives on oil production for the three and nine months ended September 30, 2006 included a volume of 40 MBbls at an average price of $76.32.

The following tables summarize open positions as of September 30, 2006 and represents, as of such date, our derivatives in place through December 31, 2010:

	October 1 December 31, 2006	Year 2007	Year 2008	Year 2009
Gas Positions				
Fixed Price Swaps:				
Hedged Volume (MMBtu)	2,625	8,968	10,264	8,005
Average Price ($/MMBtu)	$ 9.18	$ 8.72	$ 8.37	$ 7.89
Puts:				
Hedged Volume (MMBtu)	184	3,296	2,013	
Average Price ($/MMBtu)	$ 8.83	$ 9.22	$ 9.50	
Total:				
Hedged Volume (MMBtu)	2,809	12,264	12,277	8,005
Average Price ($/MMBtu)	$ 9.16	$ 8.85	$ 8.56	$ 7.89

	October 1 December 31, 2006	Year 2007	Year 2008	Year 2009	Year 2010
Oil Positions					
Fixed Price Swaps:					
Hedged Volume (MBbls)	110	500	500	500	500
Average Price ($/MBbl)	$ 77.68	$ 75.83	$ 75.83	$ 75.83	$ 75.83
Puts:					
Hedged Volume (MBbls)	36	200	200	200	200
Average Price ($/MBbl)	$ 75.00	$ 75.00	$ 75.00	$ 75.00	$ 75.00
Total:					
Hedged Volume (MBbls)	146	700	700	700	700
Average Price ($/MBbl)	$ 77.02	$ 75.60	$ 75.60	$ 75.60	$ 75.60

The oil and 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:

	September 30, 2006	December 31, 2005
Outstanding notional amounts of gas hedges (MMBtu)	35,355	28,069
Maximum number of months gas hedges outstanding	39	48
Outstanding notional amounts of oil hedges (MBbls)	2,946	
Maximum number of months oil hedges outstanding	51	

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 nine months ended September 30, 2006, the Company made payments of approximately $182,000 and $424,000, respectively, to a company owned by one of our senior executives and board members. The payments reflect reimbursement for maintenance and hourly usage fees for business use an aircraft that is partially owned by the senior executive. These costs are included in general and administrative expense on the consolidated statement of operations. The fees and expenses associated with the reimbursements were consummated on terms equivalent to those that prevail in arm s-length

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transactions. In the third quarter of 2006, the Company purchased an ownership interest in an airplane for corporate travel from a third party; therefore these reimbursements will not be ongoing. Simultaneous with this transaction, the senior executive was able to fully liquidate the investment in the aircraft owned by Linn Resources. The Company is evaluating whether the senior executive benefited from this transaction.

(14) Subsequent Event

On October 24, 2006, the Company entered into a Class B Unit and Unit Purchase Agreement with certain third party investors whereby it privately placed 9,185,965 class B units at a unit price of $20.55, and 5,534,687 units at a unit price of $21.00, for aggregate net proceeds of $305.0 million (the Private Placement).

The class B units represent a new class of equity securities that is entitled to a special quarterly distribution equal to 115% of the distribution received by the existing class A units. The class B units have no voting rights other than as required by law and are subordinated to the units on dissolution and liquidation. If approved by a vote of the Company s unitholders, the class B units will convert to units on a one-for-one basis. The Company has agreed to hold a special meeting of its unitholders to consider the conversion as soon as feasible, but no later than 90 days following the closing. Certain existing holders of Linn units totaling over 50% have committed in advance to vote at the unitholder meeting in favor of the conversion of class B units to units. In connection with the Private Placement, the Company also agreed to register the units and the units underlying the class B units with the SEC as soon as practicable, but no later than 165 days following the closing.

All proceeds from the Private Placement were used to repay in full the Company s $250.0 million Subordinated Bridge Loan, $53.3 million of borrowings under its Credit Facility and accrued interest of approximately $2.0 million (see Note 6). In connection with the repayment of the Subordinated Bridge Loan, the Company wrote off approximately $2.7 million of deferred financing fees, which was recognized as expense in October 2006.

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 oil and gas company focused on the development and acquisition of long-lived properties in the United States. We operate in the Appalachian Basin, including in West Virginia, Pennsylvania, New York and Virginia, as well as 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 January 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 $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, $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 $2.0 million was used to pay bonuses to certain executive officers of the Company. In October 2006, the Company privately placed 9,185,965 class B units at a unit price of $20.55, and 5,534,687 units at a unit price of $21.00, or a total of 14,720,652 units at a blended unit price of $20.72, for aggregate net proceeds of $305.0 million, which was used to repay indebtedness (see Private Placement below).

From inception through September 30, 2006, we have completed 14 acquisitions of oil and gas properties and related gathering and pipeline assets for an aggregate purchase price of approximately $656.0 million, with total proved reserves of approximately 441.2 Bcfe, or an acquisition cost of approximately $1.49 per Mcfe. The Company made two significant acquisitions in the third quarter of 2006. The Company acquired certain affiliated entities of Blacksand, located in the Los Angeles Basin, for an aggregate purchase price of approximately $300.7 million and certain Mid-Continent Kaiser-Francis Assets, located in Oklahoma, for an aggregate purchase price of approximately $126.3 million, in both cases subject to customary post-closing adjustments. Results of Blacksand and the Kaiser-Francis Assets are included in the consolidated results of the Company beginning August 1, 2006 and September 1, 2006, respectively. See Note 3 in the Notes to Condensed Consolidated Financial Statements for further details about the Blacksand and Kaiser-Francis acquisitions.

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
August 2006	Blacksand Energy, LLC.	388	California	300.7
August 2006	Kaiser-Francis Oil Company.	842	Oklahoma	126.3
	Total	3,344		$ 656.0

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. Oil and gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for crude oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and gas reserves that we can economically produce and our access to capital.

We utilize the successful efforts method of accounting for our oil and gas properties. Leasehold costs are capitalized when incurred. Unproved properties that are individually insignificant are amortized. Unproved properties that are individually

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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 oil and gas 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 took delivery of its first two drilling rigs and has one additional rig ordered, which will reduce or eliminate reliance on contract rigs. In the third quarter of 2006, the Company began, for the first time, operating its own drilling rigs staffed with Company personnel. Given the inherent volatility of crude oil and 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 oil and 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, oil or 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 adding 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 crude oil and natural gas prices and levels of production. As of September 30, 2006, we have hedged a significant portion of our expected production using oil and 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 crude oil and 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 crude oil and natural gas prices may have on the value of our proved reserves and their impact, if any, on any redetermination of the borrowing base under our credit facility.

Production and Operating Costs Reporting

We strive to increase our production levels to maximize our revenue and cash available for distribution. Additionally, we continuously monitor our operations to ensure that we are incurring operating costs at the lowest possible level. Accordingly, we 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 September 30, 2006 Compared to Three Months Ended September 30, 2005 (Unaudited)

The following tables set forth selected financial and operating data for the periods indicated:

	Three Months Ended September 30, 2006 (in thousands)	2005	Variance
Revenues:			
Gas sales	$ 15,553	$ 10,022	$ 5,531
Oil sales	7,953	385	7,568
Realized gain (loss) on oil and gas derivatives	8,198	1,246	6,952
Realized loss on cancelled natural gas derivatives		(30,304)	30,304
Unrealized gain on oil and gas derivatives	49,198	(21,405)	70,603
Natural gas marketing income	1,090	1,618	(528)
Other income	265	20	245
Total revenue	$ 82,257	$ (38,418)	$ 120,675
Expenses:			
Operating expenses	4,845	1,386	3,459
Natural gas marketing expense	954	1,768	(814)
General and administrative expenses	6,536	1,197	5,339
Depreciation, depletion and amortization	5,654	1,448	4,206
Total expenses	17,989	5,799	12,190
Other Income and (Expenses):			
Interest and financing expenses	$ (11,204)	$ (998)	$ (10,206)

	Three Months Ended September 30, 2006	2005	Percentage Increase (Decrease)
Production:			
Gas production (MMcf)	2,265	1,132	*
Oil production (MBbls)	153	6	*
Total production (MMcfe)	3,181	1,165	*
Average daily production (Mcfe/d)	34,576	12,663	*
Weighted Average Realized Prices:			
Gas (Mcf)	$ 10.27	$ 5.62	82.7 %
Oil (Bbl) (1)	$ 55.24	$ 59.09	(6.5)%
Total (Mcfe)	$ 9.97	$ 6.77	47.3 %
Average Unit Costs per Mcfe (Non-GAAP):			
Operating expenses	$ 1.52	$ 1.19	27.7 %
General and administrative expenses (2)	$ 0.74	$ 1.03	(28.2)%
Depreciation, depletion and amortization	$ 1.78	$ 1.24	43.5 %

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(1) The majority of our oil production, which is in California, is sold pursuant to a long-term contract at 79% of NYMEX.

(2) This is a non-GAAP performance measure used by our management and is a quantitative measure used in the oil and gas industry. The measure for the three months ended September 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 was $2.05 per Mcfe for the three months ended September 30, 2006.

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

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Revenue

Oil and gas sales increased to approximately $23.5 million, from $10.4 million during the three months ended September 30, 2006 as compared to the three months ended September 30, 2005.

The increase in revenue from oil and gas sales was primarily attributable to increased production. Total production increased to 3,181 MMcfe during the three months ended September 30, 2006, from 1,165 MMcfe during the three months ended September 30, 2005. Oil production increased to 153 MBbls during the three months ended September 30, 2006, from 6 MBbls during the three months ended September 30, 2005, primarily due to the acquisition of Blacksand in August 2006. Gas production increased to 2,265 MMcf during the three months ended September 30, 2006, from 1,132 MMcf during the three months ended September 30, 2005. The increase in gas production was due to the drilling of new wells and to production added by eight acquisitions of oil and gas properties during 2006 and 2005. The Company drilled 127 wells during 2006 (through September 30) and 110 wells in 2005.

Hedging Activities

During the three months ended September 30, 2006, we effectively hedged 90% of our gas production and 26% of our oil production, which resulted in revenues that were $8.2 million greater than we would have achieved at unhedged prices. During the three months ended September 30, 2005, we effectively hedged approximately 111% of our oil and gas production, which resulted in revenues that were $1.2 million greater than we would have achieved at unhedged prices. During the three months ended September 30, 2005, we cancelled (before their original settlement date) a portion of out-of-the-money natural gas hedges and realized a loss of $30.3 million, then subsequently hedged similar volumes at higher prices. Unrealized gain on derivatives in the amount of $49.2 million for the three months ended September 30, 2006 and unrealized loss on derivatives in the amount of $21.4 million for the three months ended September 30, 2005 were also recorded. Unrealized gains and losses result from crude oil and 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 $4.8 million for the three months ended September 30, 2006, from $1.4 million for the three months ended September 30, 2005, due to the increase in the number of producing wells as a result of the acquisitions completed in both 2006 and in 2005 and the drilling of 127 wells during 2006 (through September 30) and 110 wells during 2005. Of the 127 wells drilled during 2006, 42 were drilled during the quarter ended September 30, 2006.

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 $6.5 million, from $1.2 million during the three months ended September 30, 2006 as compared to the three months ended September 30, 2005. General and administrative expenses are presented net of approximately $0.2 million and $0.3 million during the three months ended September 30, 2006 and 2005, respectively, which represent 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 September 30, 2006, compared to none during the three months ended September 30, 2005. In addition, acquisition costs that are not eligible for capitalization, including internal and indirect costs for completed acquisitions, as well as direct costs associated with possible future acquisitions, contributed to the increase. Costs to support our rapidly growing operations, including 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 also contributed to the increase.

Depreciation, depletion and amortization increased to $5.7 million for the three months ended September 30, 2006, from $1.4 million for the three months ended September 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 September 30, 2006 and 2005, the Company capitalized approximately $2.1 million and $0.7 million, respectively, of internal costs related to drilling. Capitalized drilling costs increased compared to the prior year quarter due to the Company s placement of its own drilling rigs into service during the third quarter of 2006. The Company began, for the first time, operating its own

drilling rigs staffed with Company personnel. The aggregate amount spent on drilling and development for the three months ended September 30, 2006 and 2005 was approximately $13.0 million and $7.3 million, respectively.

Interest and financing income (expense) increased to a net expense of $11.2 million for the three months ended September 30, 2006, compared to a net expense of $1.0 million for the three months ended September 30, 2005, primarily due to increased debt levels associated with acquisitions and drilling. Cash payments for interest expense increased to $8.5 million for the three months ended September 30, 2006, from $1.9 million for the three months ended September 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 loss of approximately $0.6 million and a gain of approximately $0.8 million for the three months ended September 30, 2006 and 2005, respectively. Further, these amounts represent non-cash charges.

There was no income tax impact recorded for the three months ended September 30, 2006. Income tax was a benefit of $0.4 million for the three months ended September 30, 2005. Linn is an LLC, and is taxed substantially as a partnership.

Results of Operations - Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005 (Unaudited)

The following tables set forth selected financial and operating data for the periods indicated:

	Nine Months Ended September 30, 2006 (in thousands)	2005	Variance
Revenues:			
Gas sales	$ 44,727	$ 23,692	$ 21,035
Oil sales	8,683	716	7,967
Realized gain (loss) on oil and gas derivatives	17,361	(7,541)	24,902
Realized loss on cancelled natural gas derivatives		(38,281)	38,281
Unrealized gain (loss) on oil and gas derivatives	77,176	(26,788)	103,964
Natural gas marketing income	3,654	3,087	567
Other income	758	158	600
Total revenue	$ 152,359	$ (44,957)	$ 197,316
Expenses:			
Operating expenses	10,772	4,691	6,081
Natural gas marketing expense	3,126	3,162	(36)
General and administrative expenses	22,934	2,345	20,589
Depreciation, depletion and amortization	13,470	4,035	9,435
Total expenses	50,302	14,233	36,069
Other Income and (Expenses):			
Interest and financing expenses	$ (16,539)	$ (3,282)	$ (13,257)

	Nine Months Ended September 30, 2006	2005	Percentage Increase (Decrease)
Production:			
Gas production (MMcf)	5,977	3,156	89.4 %
Oil production (MBbls)	166	14	*
Total production (MMcfe)	6,973	3,240	*
Average daily production (Mcfe/d)	25,542	11,868	*
Weighted Average Realized Prices:			
Gas (Mcf)	$ 10.30	$ 5.12	*
Oil (Bbl) (1)	$ 55.31	$ 53.00	4.4 %
Total (Mcfe)	$ 10.15	$ 6.27	61.9 %
Average Unit Costs per Mcfe (Non-GAAP):			
Operating expenses	$ 1.54	$ 1.45	6.2 %
General and administrative expenses (2)	$ 0.98	$ 0.72	36.1 %
Depreciation, depletion and amortization	$ 1.93	$ 1.25	54.4 %

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(1) The majority of our oil production, which is in California, is sold pursuant to a long-term contract at 79% of NYMEX.

(2) This is a non-GAAP performance measure used by our management and is a quantitative measure used in the oil and gas industry. The measure for the nine months ended September 30, 2006 excludes approximately $2.0 million of bonuses paid to certain executive officers in connection with our IPO and $14.1 million of unit-based compensation expense. General and administrative expenses including these amounts was $3.29 per Mcfe for the nine months ended September 30, 2006.

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

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Revenue

Oil and gas sales increased to approximately $53.4 million, from $24.4 million during the nine months ended September 30, 2006 as compared to the nine months ended September 30, 2005.

The increase in revenue from oil and gas sales was primarily attributable to increased production. Total production increased to 6,973 MMcfe during the nine months ended September 30, 2006, from 3,240 MMcfe during the nine months ended September 30, 2005. Oil production increased to 166 MBbls during the nine months ended September 30, 2006, from 14 MBbls during the nine months ended September 30, 2005, primarily due to the acquisition of Blacksand in August 2006. Gas production increased to 5,977 MMcf during the nine months ended September 30, 2006, from 3,156 MMcf during the nine months ended September 30, 2005. The increase in gas production was due to the drilling of new wells and to production added by eight acquisitions of oil and gas properties during 2006 and 2005. The Company drilled 127 wells during 2006 (through September 30) and 110 wells in 2005.

Hedging Activities

During the nine months ended September 30, 2006, we effectively hedged 102% of our gas production and 24% of our oil production, which resulted in revenues that were $17.4 million greater than we would have achieved at unhedged prices. During the nine months ended September 30, 2005, we hedged approximately 82% of our oil and gas production, which resulted in revenues that were $7.5 million less than we would have achieved at unhedged prices. During the nine months ended September 30, 2005, we cancelled (before their original settlement date) a portion of out-of-the-money natural gas hedges and realized a loss of $38.3 million, then subsequently hedged similar volumes at higher prices. Unrealized gain on derivatives in the amount of $77.2 million for the nine months ended September 30, 2006 and unrealized loss on derivatives in the amount of $26.8 million for the nine months ended September 30, 2005 were also recorded. Unrealized gains and losses result from crude oil and 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 $10.8 million for the nine months ended September 30, 2006, from $4.7 million for the nine months ended September 30, 2005, due to the increase in the number of producing wells as a result of the acquisitions completed in both 2006 and in 2005, and the drilling of 127 wells during 2006 (through September 30) and 110 wells during 2005 (through December 31).

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 $22.9 million during the nine months ended September 30, 2006, from $2.3 million compared to the nine months ended September 30, 2005. General and administrative expenses are presented net of approximately $0.9 million and $0.8 million during the nine months ended September 30, 2006 and 2005, respectively, which represent expense reimbursements from other working interest owners. The increase in general and administrative expenses was due in part to the recognition of unit-based compensation expense of $14.1 million and $2.0 million of bonuses paid in connection with our IPO during the nine months ended September 30, 2006, neither of which were incurred during 2005. In addition, acquisition costs that are not eligible for capitalization, including internal and indirect costs for completed acquisitions, as well as direct costs associated with possible future acquisitions, contributed to the increase. Costs to support our rapidly growing operations, including 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 also contributed to the increase.

Depreciation, depletion and amortization increased to $13.5 million for the nine months ended September 30, 2006, from $4.0 million for the nine months ended September 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 nine months ended September 30, 2006 and 2005, the Company capitalized approximately $4.0 million and $1.1 million, respectively, of internal costs related to drilling. Capitalized drilling costs increased compared to the prior year period due to the Company s placement of its own drilling rigs into service during the third quarter of 2006 as noted above. The aggregate amount spent on drilling and development for the nine months ended September 30, 2006 and 2005 was approximately $26.7 million and $15.6 million, respectively.

Interest and financing income (expense) increased to a net expense of $16.5 million for the nine months ended September 30, 2006, compared to a net expense of $3.3 million for the nine months ended September 30, 2005, primarily due to increased debt levels associated with acquisitions and drilling. Cash payments for interest expense increased to approximately $13.6 million for the nine months ended September 30, 2006, from $3.6 million for the three months ended September 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 gains of approximately $0.1 million and $0.8 million for the nine months ended September 30, 2006 and 2005, respectively. Further, these amounts represent non-cash charges.

Income tax was a benefit of approximately $74,000 for the nine months ended September 30, 2006, compared to income tax expense of $0.4 million for the nine months ended September 30, 2005. Linn is an LLC, and is taxed substantially as a partnership.

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 September 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 oil and gas properties, oil and gas 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 September 30, 2006, we had cash and cash equivalents of $1.8 million compared to $11.0 million at December 31, 2005.

Cash provided by operating activities for the nine months ended September 30, 2006 was $8.0 million, compared to cash used in operating activities of $34.4 million for the nine months ended September 30, 2005. The increase in cash provided by operating activities was primarily due to the increase in net income, which was $85.3 million for the nine months ended September 30, 2006, compared to a net loss of $63.3 million for the nine months ended September 30, 2005. See Results of Operations above for detail about the increase in components of net income.

Cash used in investing activities was $509.1 million for the nine months ended September 30, 2006, compared to $28.4 million for the nine months ended September 30, 2005. The increase in cash used in investing activities was due primarily to the acquisitions of Blacksand and the Kaiser-Francis Assets in the third quarter of 2006, as well as to several other acquisitions that were completed in the second quarter of 2006. See Note 3 in the Notes to Condensed Consolidated Financial Statements.

Cash provided by financing activities was $491.8 million for the nine months ended September 30, 2006, compared to $63.6 million for the nine months ended September 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.

In the third quarter of 2006, the Company received proceeds from borrowings on its Credit Facility of $213.0 million, and from borrowing on its Subordinated Bridge Loan of $250.0 million. These proceeds were used primarily to fund the acquisitions of Blacksand and the Kaiser-Francis Assets.

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 in August 2006.

In October 2006, the Company s Board of Directors declared a distribution of $0.43 per unit with respect to the third quarter of 2006. The distribution totaling approximately $12.0 million will be paid on November 14, 2006 to unitholders of record at the close of business on October 20, 2006.

Management currently anticipates that it will recommend to the Board of Directors an increase in the annualized cash distribution of $0.36 per unit, or a 21% increase, to an annual rate of $2.08 per unit from the current annual rate of $1.72 per unit, beginning with the cash distribution expected to be paid on or about February 14, 2007 with respect to the fourth fiscal quarter of 2006. This is equivalent to a quarterly rate of $0.52 per unit.

Credit Facility

In August 2006, in connection with the acquisitions of Blacksand and the Kaiser-Francis Assets (see Note 3 in the Notes to Condensed Consolidated Financial Statements), the Company entered into an amended and restated 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 amended Credit Facility remain substantially the same as the terms under the prior facility. 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 oil and gas prices at such time. Our obligations under the Credit Facility are secured by mortgages on our oil and gas 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

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least 80% of our oil and gas 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 increased by 0.25% during the term of the Subordinated Bridge Loan, which was repaid in October 2006. 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. The Company repaid $53.0 million of borrowings under its Credit Facility in October 2006 (see Private Placement below).

Subordinated Bridge Loan

In August 2006, in order to fund a portion of the acquisitions of Blacksand and the Kaiser-Francis 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. The Company repaid in full the Subordinated Bridge Loan in October 2006 (see Private Placement below).

Private Placement

On October 24, 2006, the Company entered into a Class B Unit and Unit Purchase Agreement with certain third party investors whereby it privately placed 9,185,965 class B units at a unit price of $20.55, and 5,534,687 units at a unit price of $21.00, or a total of 14,720,652 units at a blended unit price of $20.72, for aggregate net proceeds of $305.0 million (the Private Placement).

The class B units represent a new class of equity securities that is entitled to a special quarterly distribution equal to 115% of the distribution received by the existing Class A units. The class B units have no voting rights other than as required by law and are subordinated to the units on dissolution and liquidation. If approved by a vote of the Company s unitholders, the class B units will convert to units on a one-for-one basis. The Company has agreed to hold a special meeting of its unitholders to consider the conversion as soon as feasible, but no later than 90 days following the closing. Certain existing holders of Linn units totaling over 50% have committed in advance to vote at the unitholder meeting in favor of the conversion of class B units to units. In connection with the Private Placement, the Company also agreed to register the units and the units underlying the class B units with the SEC as soon as practicable, but no later than 165 days following the closing.

All proceeds from the Private Placement were used to repay in full the Company s $250.0 million Subordinated Bridge Loan, $53.3 million of borrowings under its Credit Facility and accrued interest of approximately $2.0 million (see Note 6 in the Notes to Condensed Consolidated Financial Statements). In connection with the repayment of the Subordinated Bridge Loan, the Company wrote off approximately $2.7 million of deferred financing fees, which was recognized as expense in October 2006.

Off-Balance Sheet Arrangements

At September 30, 2006, the Company did not have any off-balance sheet arrangements that have, or are reasonably likely to have, a material effect on our financial position or results of operations.

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. Additional long-term obligations include the Company s Credit Facility (see Note 6 in the Notes to Condensed Consolidated Financial Statements) and asset retirement obligations acquired with the Company s purchase of Blacksand and the Kaiser-Francis Assets (see Note 3 in the

Notes to Condensed Consolidated Financial Statements), which constitute the significant changes to the Company s contractual obligations from December 31, 2005.

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Non-GAAP Financial Measure

Adjusted EBITDA

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

- Interest expense;
- Depreciation, depletion and amortization;
- Write-off of deferred financing fees;
- (Gain) loss on sale of assets;
- (Gain) loss from equity investment;
- Accretion of asset retirement obligation;
- Unrealized (gain) loss on oil and 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 September 30,		**Nine months ended September 30,**	
	2006	**2005**	**2006**	**2005**
	(in thousands)			
Net income (loss)	$ 53,057	$ (45,590)	$ 85,273	$ (63,265)
Plus:				
Interest expense	11,204	998	16,539	3,282
Depreciation, depletion and amortization	5,654	1,448	13,470	4,035
Write-off of deferred financing fees	161		664	364
(Gain) loss on sale of assets	(47)	3		43
Loss from equity investment				17
Accretion of asset retirement obligation	61	67	180	124
Unrealized (gain) loss on oil and gas derivatives	(49,198)	21,405	(77,176)	26,788
Realized loss on cancelled natural gas derivatives (1)		30,304		38,281

Unit-based compensation expense	4,191		14,067	
IPO cash bonuses			2,039	
Income tax provision (benefit) (2)		385	(74)	385
Adjusted EBITDA	$ 25,083	$ 9,020	$ 54,982	$ 10,054

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(1) During the three and nine months ended September 30, 2005, we cancelled (before their original settlement date) a portion of out-of-the-money natural gas swaps and realized a loss of $30.3 million and $38.3 million, respectively. 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.

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As noted above, Adjusted EBITDA is non-GAAP performance measure used by our management and is a quantitative measure used in the oil and gas industry. On our consolidated statements of cash flows, our net cash provided by operating activities for the nine months ended September 30, 2006 was approximately $8.0 million and includes approximately $77.2 million unrealized gain on oil and gas derivatives, $13.9 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 nine months ended September 30, 2005 was approximately $34.4 million and includes $26.8 million unrealized loss on oil and gas derivatives and $38.3 million realized loss on cancelled natural gas derivatives.

New Accounting Standards

There have been no accounting standards adopted 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;
- oil and gas reserves;
- realized oil and gas 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 and in the reports and other information we file with the SEC. 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 crude oil prices, 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 oil and 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 crude oil and 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 crude oil and 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 crude oil and natural gas prices at targeted levels and to manage our exposure to crude oil and natural gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

At September 30, 2006, the fair value of hedges that settle during the next twelve months was an asset of approximately $30.4 million and a liability of approximately $0.6 for a net asset of approximately $29.8 million, which we are owed from the counterparty. A 10% increase in the index natural gas price above the September 30, 2006 price for the next twelve months would result in a reduction of approximately $10.8 million; conversely, a 10% decrease in the index natural gas price would result in an increase of approximately $10.8 million.

Our derivatives as of September 30, 2006, for 2006 through 2010, are summarized in the table presented in Note 12 in the Notes to Condensed Consolidated Financial Statements.

Interest Rate Risk

At September 30, 2006, we had long-term debt outstanding of $406.0 million under our Credit Facility, which incurred interest at floating rates in accordance the Credit Facility agreement. As of September 30, 2006, the one-month LIBOR was approximately 5.3%. A 1% increase in the one-month LIBOR would result in an estimated $4.1 million increase in annual interest expense.

In order to finance the acquisitions of Blacksand and the Kaiser-Francis Assets in August 2006, the Company modified its 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 October 2006, proceeds from the Private Placement were used to repay in full the Company s $250.0 million Subordinated Bridge Loan, $53.3 million of borrowings under its Credit Facility and accrued interest of approximately $2.0 million (see Note 14 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 3.17% and 4.40%, 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 5.30% and 5.79%, respectively, while receiving a floating interest rate.

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 3.08% and 4.42%, respectively, while receiving a floating interest rate.

A 1% change in LIBOR from the rate at September 30, 2006, would result in an estimated $1.5 million change in annual 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.

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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.

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.

Due to the material weakness described below, our CEO and CFO continue to conclude that our disclosure controls and procedures were not effective as of September 30, 2006. As noted below, we believe we have taken the necessary steps to address the matters related to the material weakness. However, before concluding that the material weakness has been remediated, management believes that the new internal controls should be implemented and operational for a sufficient period of time to demonstrate that the controls are operating effectively. We believe our consolidated financial statements included in this Quarterly Report on Form 10-Q fairly present in all material respects our financial position, results of operations and cash flows for the periods presented in accordance with United States generally accepted accounting principles.

Material weaknesses in internal control. 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.

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. We undertook numerous remedial actions, as described below, to enhance controls.

Remediation activities. During 2006, Company management has taken the following steps to strengthen internal control over financial reporting.

1. We engaged outside consultants with extensive 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.

5. We hired experienced personnel with technical accounting, financial reporting and oil and gas experience.

6. We provided extensive training on our accounting software system to both new and established accounting personnel.

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We believe we have taken the necessary steps to address the matters related to the material weakness described above. However, before concluding that the material weakness has been remediated, management believes that the new internal controls should be implemented and operational for a sufficient period of time to demonstrate that the controls are operating effectively.

(b) Changes and remediation in the Company s internal control over financial reporting

In response to the material weakness noted in 4(a) above, during the three months ended September 30, 2006, Company management has taken the following remedial actions (i) hiring experienced personnel with technical accounting, financial reporting and oil and gas experience, (ii) providing extensive training on our accounting software system to both new and established accounting personnel and (iii) continuing to perform and to enhance additional analysis and other post closing procedures, including certain review and monitoring controls over account reconciliation. These three items constitute the 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 September 30, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

Not applicable.

Item 1A. Risk Factors

Our business has many risks. As of the date of this report, factors that have materially changed from those reported in Item 1A. Risk Factors in our Quarterly Report on Form 10-Q for the three and six months ended June 30, 2006, 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 have significant indebtedness under our Credit Facility. Our Credit Facility has 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 significant indebtedness under our Credit Facility. As of November 1, 2006, we had approximately $352.8 million outstanding under our Credit Facility (with additional borrowing capacity of approximately $123.2 million). 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 oil and gas 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 2/3% of the commitments. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other oil and gas 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 oil or gas 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 November 1, 2006, we had approximately $352.8 million of indebtedness outstanding under the Credit Facility, 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.

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

For the nine months ended September 30, 2006, Dominion Resources, Inc., Cabot Oil & Gas Corporation, ConocoPhillips and Amerada Hess Corporation accounted for approximately 60%, 10%, 8% and 3%, respectively, of our total volumes, or 81% in the aggregate. 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. To the extent these and other customers reduce the volumes of oil or gas that they purchase from us, our revenues and cash available for distribution could decline.

Our management and Quantum Energy Partners own, in the aggregate, a significant interest in us, with management and Quantum Energy Partners owning approximately 13.6% and 30.4%, respectively, of our outstanding units.

Our management and Quantum Energy Partners own or control an aggregate 40.0% of our outstanding units (without giving effect to the potential conversion of 9,185,965 non-voting Class B units into units). Accordingly, management and Quantum Energy Partners, acting together, possess significant voting power on substantially all matters submitted to a vote of the holders of our units. 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.

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

As of November 1, 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 also completed a private offering of 5,534,687 units and 9,185,965 newly created Class B units on October 24, 2006. In connection with the Private Placement, we also agreed to register the units and the units underlying the class B units with the SEC as soon as practicable, but no later than 165 days following the closing. If the purchasers were to sell a substantial portion of their units, then the market price of our outstanding units may decline.

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 INDEX

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
3.4	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC
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)
4.2	Form of Class B specimen unit certificate for the Class B units of Linn Energy, LLC (incorporated herein by reference to Exhibit 4.2 to the Current Report on Form 8-K filed by Linn Energy, LLC on October 24, 2006)
10.1*	Form of Linn Energy, LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.10 to Amendment No. 4 to the Registration Statement on Form S-1 filed by Linn Energy, LLC on December 14, 2005)
10.2*	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)
10.3*	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)
10.4*	Linn Energy, LLC Long-Term Incentive Plan Restricted Unit Agreement, dated effective as of July 17, 2006 between Linn Energy, LLC and Lisa D. Anderson
10.5*	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)
10.6	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))
10.7	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)
10.8	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)

10.9	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)
31.1	Rule 13a-14(a)/15d-14(a) Certification of Michael C. Linn, Chairman, President and Chief Executive Officer of Linn Energy, LLC
31.2	Rule 13a-14(a)/15d-14(a) Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC
32.1	Section 1350 Certification of Michael C. Linn, Chairman, President and Chief Executive Officer of Linn Energy, LLC
32.2	Section 1350 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC

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: November 14, 2006

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