LINN ENERGY, LLC
Form 10-Q
November 09, 2007

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

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

For the Quarterly Period Ended September 30, 2007

OR

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 (State or other jurisdiction of incorporation or organization)	**65-1177591** (IRS Employer Identification No.)
600 Travis, Suite 5100 **Houston, Texas** (Address of principal executive offices)	**77002** (Zip Code)

(281) 840-4000

(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 2, 2007, there were 113,712,436 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 gas to one Bbl of 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.

FERC. Federal Energy Regulatory Commission.

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

LIBOR. London Interbank Offered Rate.

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

Mcf. One thousand cubic feet.

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

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

MMboe. One million barrels of oil equivalent determined using a ratio of six Mcf of gas to one Bbl of oil, condensate or natural gas liquids.

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 gas to one Bbl of 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.

NGL. Natural gas liquids, which are the hydrocarbon liquids contained within gas.

NYMEX. The New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

PEPL. Panhandle Eastern Pipeline.

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 gas, natural gas liquids and 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. The definition of proved reserves is in accordance with the Securities and Exchange Commission s definition set forth in Regulation S-X Rule 4-10(a) and its subsequent staff interpretations and guidance.

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 economically productive oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Royalty interest. An interest that entitles the owner of such interest to a share of the mineral production from a property or to a share of the proceeds therefrom. It does not contain the rights and obligations of operating the property and normally does not bear any of the costs of exploration, development, and operation of the property.

Standardized Measure. Standardized Measure, or standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities, 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%. The Company s Standardized Measure does not include future income tax expenses because the reserves are owned by its subsidiaries which are 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, 2007 (Unaudited)	December 31, 2006
	(in thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 33,588	$ 6,595
Receivables trade, net	96,645	19,124
Inventories	2,781	578
Current portion of derivatives	77,884	37,817
Current portion of deferred tax assets, net		3,344
Other current assets	1,186	2,218
Total current assets	212,084	69,676
Oil and gas properties and related equipment (successful efforts method)	3,416,788	766,638
Less accumulated depreciation, depletion and amortization	(79,702)	(33,349)
	3,337,086	733,289
Property and equipment, net	34,956	20,754
Other assets:		
Derivatives	265,696	70,435
Deposit for oil and gas properties		20,086
Deferred financing fees and other assets, net	9,209	2,068
	274,905	92,589
Total assets	$ 3,859,031	$ 916,308

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED BALANCE SHEETS

		September 30, 2007 (Unaudited)		December 31, 2006
		(in thousands, except unit amounts)		
Liabilities and Unitholders Capital				
Current liabilities:				
Accounts payable and accrued expenses	$	55,674	$	12,759
Current portion of derivatives		31,256		462
Joint interest payable		9,294		1,839
Accrued interest payable		5,267		2,084
Other liabilities		666		873
Total current liabilities		102,157		18,017
Long-term liabilities:				
Credit facility		1,302,000		425,750
Asset retirement obligation		27,124		8,594
Derivatives		136,408		10,357
Other long-term liabilities		2,547		2,636
Total long-term liabilities		1,468,079		447,337
Total liabilities		1,570,236		465,354
Unitholders capital:				
78,640,050 units and 33,617,187 units issued and outstanding at September 30, 2007 and December 31, 2006, respectively		1,366,035		246,034
9,185,965 Class B units issued and outstanding at December 31, 2006				188,590
34,997,005 Class D units issued and outstanding at September 30, 2007		1,067,625		
Accumulated income (loss)		(144,865)		16,330
		2,288,795		450,954
Total liabilities and unitholders capital	$	3,859,031	$	916,308

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands, except per unit amounts)			
Revenues:				
Oil, gas and natural gas liquid sales	$ 75,062	$ 23,506	$ 163,483	$ 53,410
Gain (loss) on oil and gas derivatives	(65,440)	57,396	(143,588)	94,537
Natural gas marketing revenues	8,434	1,090	11,351	3,654
Other revenues	423	265	3,652	758
	18,479	82,257	34,898	152,359
Expenses:				
Operating expenses	27,465	4,845	54,635	10,772
Natural gas marketing expenses	7,207	954	9,433	3,126
General and administrative expenses	13,202	6,536	36,360	22,934
Depreciation, depletion and amortization	24,320	5,654	49,109	13,470
	72,194	17,989	149,537	50,302
	(53,715)	64,268	(114,639)	102,057
Other income and (expenses):				
Interest expense, net of amounts capitalized	(16,613)	(10,700)	(36,675)	(16,873)
Gain (loss) on interest rate swaps	(3,151)	(504)	(2,954)	334
Other expenses, net	(2,422)	(7)	(2,944)	(319)
	(22,186)	(11,211)	(42,573)	(16,858)
Income (loss) before income taxes	(75,901)	53,057	(157,212)	85,199
Income tax benefit (provision)	(321)		(3,983)	74
Net income (loss)	$ (76,222)	$ 53,057	$ (161,195)	$ 85,273
Net income (loss) per unit:				
Units basic	$ (0.94)	$ 1.92	$ (2.60)	$ 3.14
Units diluted	$ (0.94)	$ 1.89	$ (2.60)	$ 3.12
Class D basic	$ (0.94)	$	$ (2.60)	$
Class D diluted	$ (0.94)	$	$ (2.60)	$
Weighted average units outstanding:				
Units basic	69,207	27,584	58,072	27,118
Units diluted	69,207	28,044	58,072	27,341
Class D basic	11,792		3,974	
Class D diluted	11,792		3,974	
Distributions declared per unit	$ 0.57	$ 0.40	$ 1.61	$ 0.72

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF UNITHOLDERS CAPITAL

(Unaudited)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands)			
Unitholders capital:				
Balance, beginning of period	$ 990,702	$ 141,355	$ 434,624	$ 16,024
Sale of units, net of expenses of $4,339				225,139
Sale of private placement units, net of expenses of $22,804 and $34,272	1,477,196		2,085,728	
Cancellation of member interests				(100,778)
Cancellation of units			(7,399)	
Distribution to unitholders	(37,419)	(11,033)	(90,165)	(19,859)
Unit-based compensation and unit warrant expense	3,199	4,068	10,890	13,864
Exercise of unit options	(18)		(18)	
Balance, end of period	2,433,660	134,390	2,433,660	134,390
Accumulated income (loss):				
Balance, beginning of period	(68,643)	(30,639)	16,330	(62,855)
Net income (loss)	(76,222)	53,057	(161,195)	85,273
Balance, end of period	(144,865)	22,418	(144,865)	22,418
Treasury units (at cost):				
Balance, beginning of period				
Purchase of units			(7,399)	
Sale of units				13,671
Redemption of member interests				(114,449)
Cancellation of member interests				100,778
Cancellation of units			7,399	
Balance, end of period				
Total unitholders capital	$ 2,288,795	$ 156,808	$ 2,288,795	$ 156,808

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30, 2007	2006
	(in thousands)	
Cash flow from operating activities:		
Net income (loss)	$ (161,195)	$ 85,273
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	49,109	13,470
Amortization and write-off of deferred financing fees and other	3,531	1,650
Gain on sale of assets	(867)	
Accretion of asset retirement obligation	577	180
Unit-based compensation and unit warrant expense	10,890	13,864
Deferred income tax	3,359	(307)
Mark-to-market on derivatives:		
Total (gains) losses	146,542	(94,637)
Realized gains	24,896	11,447
Premiums paid for derivatives	(257,092)	(14,228)
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	(47,163)	(3,089)
Decrease in inventory and other assets	3,443	3,542
Increase (decrease) in derivative receivables	7,171	(474)
Increase (decrease) in accounts payable and accrued expenses	16,750	(5,821)
Increase in accrued interest payable	3,183	2,284
Increase (decrease) in joint interest payable	7,455	(5,101)
Increase (decrease) in other liabilities	1,443	(69)
Net cash provided by (used in) operating activities	(187,968)	7,984
Cash flow from investing activities:		
Acquisition of oil and gas properties	(2,572,614)	(469,274)
Development of oil and gas properties	(54,170)	(33,573)
Purchases of property and equipment	(12,494)	(6,259)
Proceeds from sale of assets	2,974	21
Net cash used in investing activities	(2,636,304)	(509,085)
Cash flow from financing activities:		
Proceeds from sale of units	2,120,000	243,149
Redemption and cancellation of units	(7,399)	(114,449)
Principal payments on notes payable	(2,197)	(597)
Proceeds from credit facilities	1,140,000	261,303
Payments on credit facilities	(263,750)	(62,000)
Proceeds from subordinated term loan		250,000
Principal payments on subordinated term loan		(60,000)
Distribution to members	(90,165)	(19,859)
Offering costs	(34,272)	(844)
Financing fees and other	(10,952)	(4,881)
Net cash provided by financing activities	2,851,265	491,822
Net increase (decrease) in cash	26,993	(9,279)

Cash and cash equivalents:				
Beginning		6,595		11,041
Ending	$	33,588	$	1,762

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS SUPPLEMENTAL DISCLOSURES

(Unaudited)

	Nine Months Ended September 30, 2007	2006
	(in thousands)	
Supplemental disclosure of cash flow information:		
Cash payments for interest	$ 29,339	$ 13,603
Supplemental disclosures of non-cash investing and financing activities:		
Acquisitions of vehicles and equipment through issuance of notes payable	$ 486	$ 2,648
In connection with the purchase of oil and gas properties, liabilities were assumed as follows:		
Fair value of assets acquired	$ 2,581,913	$ 472,499
Cash paid	(2,572,614)	(469,274)
Liabilities assumed, net	$ 9,299	$ 3,225

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 and Significant Accounting Policies

Linn Energy, LLC (Linn or the Company) is an independent oil and gas company focused on the development and acquisition of long-lived properties in the United States that began operations in March 2003 and was formed as a Delaware limited liability company in April 2005.

The condensed consolidated financial statements at September 30, 2007, and for the three and nine months ended September 30, 2007 and 2006, 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 United States 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 the Company s Annual Report on Form 10-K for the year ended December 31, 2006. Certain amounts in the condensed consolidated financial statements and notes thereto have been reclassified to conform to the 2007 financial statement presentation.

The condensed consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. All significant intercompany transactions and balances have been eliminated upon consolidation.

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, gas and natural gas liquid (NGL) reserves, future cash flows from oil and gas properties, depreciation, depletion and amortization, asset retirement obligations, the fair value of derivatives and unit-based compensation expense.

As of September 30, 2007, 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, 2006. The policies disclosed included the accounting for oil and gas properties, reserve quantities, revenue recognition, purchase accounting and derivative instruments. Several of the more significant accounting policies are summarized below.

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

Depreciation and depletion of producing oil and gas properties is recorded based on units of production. Unit rates are computed in accordance with Statement of Financial Accounting Standards (SFAS) No. 19, as amended, *Financial Accounting and Reporting by Oil and Gas Producing Companies* (SFAS 19), which 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.

Derivative Instruments and Hedging Activities

The Company uses derivative financial instruments to achieve a more predictable cash flow from its oil, gas and NGL production by reducing its exposure to price fluctuations. As of September 30, 2007, 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. The Company accounts for these activities pursuant to SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended, (SFAS 133). This statement establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the balance sheets as assets or liabilities. None of the Company s commodity or interest rate derivatives are designated as hedges under SFAS 133 and therefore the change in the fair value of the derivatives is included in the condensed consolidated statements of operations. See Note 11 for additional discussion related to derivative financial instruments.

Unit-Based Compensation

Under the provisions of the Linn Energy, LLC Long-Term Incentive Plan, which is administered by the Compensation Committee of the Board of Directors, the Company has awarded unit grants, unit options, restricted units, and phantom units to employees and non-employee directors. The unit options and restricted units vest ratably over one to three years from the grant date of the award, unless other contractual arrangements are made. The contractual life of unit options is ten years. See Note 13 for details regarding unit-based compensation granted during the nine months ended September 30, 2007.

The Company accounts for unit-based compensation under the provisions of SFAS No. 123 (revised 2004), *Share Based Payment* (SFAS 123R). SFAS 123R requires the recognition of compensation expense, over the requisite service period, in an amount equal to the fair value of unit-based payments granted.

Inventories

Materials, supplies and commodity inventories are valued at the lower of average cost or market, determined by the first-in-first-out method.

Recently Issued Accounting Standards

In June 2007, the Financial Accounting Standards Board (FASB) ratified the consensus in Emerging Issues Task Force Issue 06-11 (EITF 06-11). EITF 06-11 is effective for fiscal years beginning after December 15, 2007 and requires, among other things, recognition as an increase to additional paid-in capital the realized income tax benefit from dividends or dividend equivalents that are paid to employees and charged to retained earnings. The Company is in the process of evaluating the impact of EITF 06-11 on its results of operations and financial position, but does not expect it will be material.

In April 2007, the FASB issued Staff Position No. 39-1, *Amendment of FASB Interpretation No. 39* (FSP No. FIN 39-1). The terms conditional contracts and exchange contracts have been replaced with the more general term derivative contracts. In addition, FSP No. FIN 39-1 permits the offsetting of recognized fair values for the right to reclaim cash collateral or the obligation to return cash collateral against fair values of derivatives under certain circumstances, such as under master netting arrangements. Additional disclosure is also required regarding a Company s accounting policy with respect to offsetting fair value amounts. The guidance in FSP No. FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application allowed. The effects of initial adoption should be recognized as a change in accounting principle through retrospective application for all periods presented. The Company does not believe that the adoption of FSP No. FIN 39-1 will have a material impact on its results of operations or financial position.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115* (SFAS 159), which permits companies to choose, at specified dates, to measure certain eligible financial instruments at fair value. The objective of SFAS 159 is to reduce volatility in preparer reporting that may be caused as a result of measuring related financial assets and liabilities differently and to expand the use of fair value measurements. The provisions of SFAS 159 apply only to entities that elect to use the fair value option and to all entities with available-for-sale and trading securities. Additional disclosures are also required for instruments for which the fair value option is elected. SFAS 159 is effective for fiscal years beginning after November 15, 2007. No retrospective application is allowed, except for companies that choose to adopt early. At the effective date, companies may elect the fair value option for eligible items that exist at that date, and the effect of the first remeasurement to fair value must be reported as a cumulative-effect adjustment to the opening balance of retained earnings. The Company is currently evaluating what impact, if adopted, SFAS 159 may have on its results of operations or financial position.

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 mark-to-market 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.

(2) Acquisitions and Dispositions

On February 1, 2007, effective January 1, 2007, the Company completed the acquisition of certain oil and gas properties and related assets in the Texas Panhandle from Stallion Energy LLC, acting as general partner for Cavallo Energy, LP, for a contract price of $415.0 million (Panhandle I). The Panhandle I acquisition was financed with a combination of a private placement of units (see Note 3) and borrowings under the Company s credit facility (see Note 6).

On June 12, 2007, effective April 1, 2007, the Company completed the acquisition of certain oil and gas properties in the Texas Panhandle for a contract price of $90.5 million (Panhandle II). The acquisition was financed with borrowings under the Company s credit facility.

On August 31, 2007, effective July 1, 2007, the Company completed the acquisition of certain oil and gas properties in the Mid-Continent, in Oklahoma, Kansas and the Texas Panhandle for a contract price of $2.05 billion from Dominion Resources, Inc. and certain affiliates (Dominion) (Mid-Continent). On August 31, 2007, the Company completed the private placement of $1.5 billion of units and Class D units to a group of institutional investors (see Note 3). In addition, on August 31, 2007, the Company entered into a new $1.8 billion credit facility (see Note 6). The Company funded the Mid-Continent acquisition with the net proceeds from the private placement, together with borrowings under its credit facility.

The following table presents the preliminary purchase accounting for the Panhandle I, Panhandle II and Mid-Continent acquisitions, based on preliminary estimates of fair value:

	Panhandle I		Panhandle II (in thousands)		Mid-Continent	
Cash	$	411,287	$	90,179	$	2,022,606
Estimated transaction costs		2,996		366		6,790
Estimated pending closing adjustments				(1,440)		(23,500)
		414,283		89,105		2,005,896
Fair value of liabilities assumed		1,706		1,034		24,569
Total purchase price	$	415,989	$	90,139	$	2,030,465

The following table presents the preliminary allocation of the purchase prices based on preliminary estimates of fair value:

	Panhandle I		Panhandle II (in thousands)		Mid-Continent	
Accounts receivable	$		$		$	27,915
Other current assets				644		6,326
Oil and gas properties		415,251		89,495		2,017,189
Property, plant and equipment		738				3,604
Accounts payable and accrued expenses						(24,569)
	$	415,989	$	90,139	$	2,030,465

The preliminary purchase prices and purchase price allocations above are based on preliminary reserve reports, quoted market prices and estimates by management. The most significant assumptions are related to the estimated fair values assigned to proved oil and gas properties. To estimate the fair values of these properties, the Company utilized preliminary estimates of oil, gas and NGL reserves prepared by an independent engineering firm. The Company estimated future prices to apply to the estimated reserve quantities acquired, and estimated future operating and development costs, to arrive at estimates of future net revenues. The Company also reviewed comparable purchases and sales of oil and gas properties within the same regions. As noted, the purchase prices and the allocations of the purchase prices are preliminary. Items pending completion include final closing adjustments for all three acquisitions and for the Mid-Continent acquisition include completion of independent appraisals of fixed assets, and additional analysis related to the fair value of proved and unproved oil and gas reserves, including discounted cash flows and market-based data, and the valuation of certain assumed liabilities. The purchase prices and purchase price allocations will be finalized within one year of the acquisition dates.

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, 2007 and 2006, assuming the Panhandle I, Panhandle II and Mid-Continent acquisitions and the related private placement of units and Class D units (see Note 3) had been completed as of January 1, 2006, including adjustments to reflect the allocation of the purchase prices to the acquired net assets. The pro forma financial information also assumes that the acquisitions of California assets from affiliated entities of Blacksand Energy, LLC and Oklahoma assets from Kaiser-Francis Oil Company were completed as of January 1, 2006. The California and Oklahoma acquisitions were completed in 2006 and the revenues and expenses are included in the consolidated results of the Company effective August 1, 2006 and September 1, 2006, respectively. The revenues and expenses of the Panhandle I and Panhandle II assets are included in the consolidated results of the Company as of February 1, 2007 and June 12, 2007, respectively. The revenues and expenses of the Mid-Continent assets are

included in the consolidated results of the Company effective September 1, 2007. The pro forma financial information is not necessarily indicative of the results of operations if the acquisitions had been effective as of these dates.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands, except per unit amounts)			
Total revenues	$ 75,479	$ 196,228	$ 261,791	$ 534,305
Total operating expenses	$ 92,487	$ 78,318	$ 274,741	$ 238,419
Net income (loss)	$ (43,023)	$ 91,086	$ (90,447)	$ 220,365
Net income (loss) per unit:				
Units basic	$ (0.38)	$ 1.21	$ (0.86)	$ 2.93
Units diluted	$ (0.38)	$ 1.20	$ (0.86)	$ 2.93
Class D units basic	$ (0.38)	$ 1.21	$ (0.86)	$ 2.93
Class D units diluted	$ (0.38)	$ 1.20	$ (0.86)	$ 2.93

The unaudited pro forma condensed combined statements of operations present net income (loss) per unit allocated to the units and the Class D units on an equal basis. In November 2007, at a special meeting of Linn unitholders, unitholders approved the one-for-one conversion of each of the Class D units into units. Therefore, pro forma net income (loss) per unit assumes that the units and Class D units share equally in the pro forma net income (loss) of the Company.

In addition, during 2007, the Company completed the following other acquisitions:

January 2007 gas properties located in the Appalachian Basin of West Virginia for a contract price of $39.0 million

April 2007 net profits interest in oil and gas properties in California for a contract price of $10.0 million

October 2007 working or royalty interests in oil and gas properties primarily in the Mid-Continent in two separate transactions for contract prices totaling $74.5 million

In March 2007, the Company sold certain of its oil and gas properties located in New York for cash of approximately $2.5 million and recorded a gain of approximately $0.9 million. The gain is included in other revenues on the condensed consolidated statements of operations.

(3) Unitholders Capital

August 2007 Private Placement

In August 2007, the Company closed its private placement of $1.5 billion of units to a group of institutional investors, consisting of 34,997,005 Class D units at a price of $30.97 per unit and 12,999,989 units at a price of $32.00 per unit (August 2007 Private Placement). Proceeds, net of expenses, were $1.48 billion and were used to fund the Mid-Continent acquisition (see Note 2).

The Class D units represent a class of equity securities that is entitled to a special quarterly distribution equal to 115% of the distribution received by the holders of units, has no voting rights other than as required by law and is subordinated to the units on dissolution and liquidation. In November 2007, at a special meeting of Linn unitholders, unitholders approved the one-for-one conversion of the Class D units into units. In connection with the August 2007 Private Placement, the Company agreed to file a Registration Statement with the SEC covering the units and the Class D units. See Liquidated Damages below for details regarding potential penalties that could be incurred by the Company in the event the Registration Statement is not declared effective by the SEC on or prior to February 12, 2008.

June 2007 Private Placement

In June 2007, the Company closed its private placement of $260.0 million of units to a group of institutional investors, consisting of 7,761,194 units at a price of $33.50 per unit (the June 2007 Private Placement). Proceeds, net of expenses, were $255.2 million and were used to repay indebtedness under the Company s credit facility (see Note 6). In connection with the June 2007 Private Placement, the Company agreed to file a Registration Statement with the SEC covering the units. As discussed below under February 2007 Private Placement and October 2006 Private Placement, the Company s Registration Statement on Form S-3, as amended, to register units issued in the October 2006 and February 2007 offerings, has not yet been declared effective by the SEC. Under the terms of the registration rights agreement with the purchasers in the June 2007 Private Placement, the Company cannot file a Registration Statement to register the units issued in the June 2007 Private Placement until the Registration Statement covering the units issued in the February 2007 and October 2006 Private Placements is declared effective. See Liquidated Damages below for details regarding potential penalties that could be incurred by the Company in the event the Registration Statement is not declared effective by the SEC on or prior to November 13, 2007.

February 2007 Private Placement

In February 2007, the Company closed its private placement of $360.0 million of units to a group of institutional investors, consisting of 7,465,946 Class C units at a price of $25.06 per unit, and 6,650,144 units at a price of $26.00 per unit (the February 2007 Private Placement). Proceeds, net of expenses, were $353.1 million and were used to finance the Panhandle I acquisition and the acquisitions of certain gas properties in West Virginia (see Note 2).

The Class C units were converted into units on a one-for-one basis in April 2007. The Company filed a Registration Statement on Form S-3 with the SEC covering the units in September 2007 and Amendment No. 1 to Form S-3 in October 2007. Under the registration rights agreement, as amended, liquidated damages could become payable if the Registration Statement is not declared effective by the SEC on or prior to December 31, 2007. The Registration Statement, as amended, has not yet been declared effective by the SEC. See Liquidated Damages below.

October 2006 Private Placement

In connection with its October 2006 private placement of units and Class B units (Class B units were converted to units on a one-for-one basis in January 2007), (the October 2006 Private Placement), the Company filed a Registration Statement on Form S-3 with the SEC covering the units in September 2007 and Amendment No. 1 to Form S-3 in October 2007. Under the registration rights agreement, as amended, liquidated damages could become payable if the Registration Statement is not declared effective by the SEC on or prior to December 31, 2007. The Registration Statement, as amended, has not yet been declared effective by the SEC. See Liquidated Damages below.

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Liquidated Damages

The Company could be required to pay purchasers liquidated damages specified in agreements pursuant to the October 2006, February 2007, June 2007 and August 2007 Private Placements in the event the registration effectiveness deadlines noted above are not achieved. The potential payments under the agreements are 0.25% of the gross proceeds for each 30 day period that the registration deadlines are not met, up through 90 days. Subsequent to 90 days, the potential payments would increase for each 30 day period, up to a maximum of 1.0% of the gross proceeds of each offering. As of the date of this report, based on the facts discussed in June 2007 Private Placement above, it is reasonably possible that the Company may be required to make some amount of such payments; however, the Company does not expect payments under these agreements to be material to the Company s financial position or results of operations.

Cancellation of Units

In January 2007, the Company purchased 226,561 restricted units from an employee for $7.4 million (market price on the day of purchase) in conjunction with the vesting of restricted unit awards. The proceeds were used to fund the employee s payroll taxes on the award, and the Company cancelled the units.

Issuance of Units

In October 2007, the Company issued 77,381 units in connection with the acquisition of royalty interests in certain oil and gas properties.

Initial Public Offering

In the first quarter of 2006, the Company completed its initial public offering (IPO) of 12,450,000 units representing limited liability company interests 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, $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.

(4) Oil and Gas Capitalized Costs

Aggregate capitalized costs related to oil, gas and NGL production activities with applicable accumulated depreciation, depletion and amortization are presented below:

	September 30, 2007	December 31, 2006
	(in thousands)	
Unproved properties	$ 9,117	$ 8,624
Proved properties:		
Leasehold, equipment and drilling	3,288,130	737,202
Gas compression plant and pipelines	119,541	20,812
	3,416,788	766,638
Less accumulated depletion, depreciation and amortization	(79,702)	(33,349)
Net capitalized costs	$ 3,337,086	$ 733,289

(5) Property and Equipment

Property and equipment consists of the following:

	September 30, 2007	December 31, 2006
	(in thousands)	
Land	$ 326	$ 308
Buildings and leasehold improvements	8,178	2,759
Vehicles	7,203	3,097
Aircraft	5,890	5,890
Drilling and other equipment	12,909	8,611
Furniture and office equipment	4,748	1,966
	39,254	22,631
Less accumulated depreciation	(4,298)	(1,877)
	$ 34,956	$ 20,754

Depreciation expense for the three and nine months ended September 30, 2007, was approximately $1.0 million and $2.5 million, respectively. Depreciation expense for the three and nine months ended September 30, 2006, was approximately $0.2 million and $0.6 million, respectively.

(6) Credit Facility

On August 31, 2007, the Company entered into a $1.8 billion Third Amended and Restated Credit Agreement (Credit Facility), which amended and restated the Company s prior credit facility. The Credit Facility has an available borrowing base of $1.8 billion, of which $1.65 billion is conforming, and a maturity of August 2010. In connection with its new Credit Facility, the Company paid approximately $9.3 million in financing fees, which were deferred and are being amortized over the life of the Credit Facility. In addition, during the three and nine months ended September 30, 2007, the Company wrote off deferred financing fees related to its prior credit facility of approximately $2.2 million and $2.8 million, respectively.

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. The Company s obligations under the Credit Facility are secured by mortgages on its oil and gas properties as well as a pledge of all ownership interests in its operating subsidiaries. The Company is required to maintain the mortgages on properties representing at least 80% of its oil and gas properties. Additionally, the obligations under the Credit Facility are guaranteed by all of the Company s operating subsidiaries and may be guaranteed by any future subsidiaries.

At the Company s election, interest on borrowings under the Credit Facility is determined by reference to either LIBOR plus an applicable margin between 1.00% and 2.25% per annum or the alternate base rate (ABR) plus an applicable margin between 0% and 0.75% per annum. Interest is generally payable quarterly for ABR loans and at the applicable maturity date for LIBOR loans.

The Credit Facility contains various covenants, substantially similar to the prior credit facility, that limit the Company s ability to incur indebtedness, enter into interest rate swaps, grant certain liens, make certain loans, acquisitions, capital expenditures and investments, make distributions other than from available cash, merge or consolidate, or engage in certain asset dispositions, including a sale of all or substantially all of its assets. The Credit Facility also contains covenants, substantially similar to the prior credit facility, that require the

Company to maintain specified financial ratios. The other terms and conditions of the Credit Facility are substantially similar to the prior credit facility.

As of September 30, 2007 and December 31, 2006, the Credit Facility consisted of the following:

	September 30, 2007		December 31, 2006	
	(in thousands)			
Total (1)	$	1,302,000	$	425,750
Less current maturities				
	$	1,302,000	$	425,750

(1) Variable rate of 7.188% and 7.125% at September 30, 2007 and December 31, 2006, respectively.

At September 30, 2007, the Company also had $2.5 million outstanding letters of credit, which reduce its borrowing availability under the Credit Facility. At September 30, 2007, available borrowing under the Credit Facility was $495.5 million. See Note 8 for details about the Company s interest rate swaps.

(7) Long-term Notes Payable

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

	September 30, 2007		December 31, 2006	
	(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.	$	363	$	372
Various notes for the purchase of vehicles and equipment, payable in monthly installments totaling approximately $59 and $88, as of September 30, 2007 and December 31, 2006, respectively, including interest. The interest rates range from 3.90%-8.25%. The notes are secured by the vehicles and equipment purchased and expire at various dates from 2007 through 2011. (1)		1,259		2,988
		1,622		3,360
Less current maturities		(666)		(873)
	$	956	$	2,487

(1) At September 30, 2007 and December 31, 2006, includes approximately $1.1 million and $1.0 million, respectively, of notes payable on which interest was imputed at 7.0%.

As of September 30, 2007, maturities on the aforementioned long-term notes payable were as follows:

	(in thousands)
2007	$ 159
2008	601
2009	406
2010	126
2011	28
Thereafter	302
	$ 1,622

(8) Interest Rate Swaps

The Company has periodically entered into interest rate swap agreements to minimize the effect of fluctuations in interest rates. The Company is required to pay the counterparties the difference between the contract s fixed rate and the actual rate if the actual rate is lower than the fixed rate and conversely, the counterparties are required to pay the Company if the actual rate is higher than the fixed rate in the contract. The Company did not designate the interest rate swap agreements as cash flow hedges under SFAS 133; therefore, the changes in fair value of these instruments, which are non-cash gains or losses, are recorded in current earnings.

The following summarizes the Company s interest rate swaps outstanding:

	September 30, 2007	December 31, 2006
	(in thousands)	
Total liabilities	$ 8,550	$ 423
Less total assets	(5,127)	(44)
	$ 3,423	$ 379

Unrealized gains (losses) due to the change in the fair value of approximately $(3.8) million and $(3.7) million for the three and nine months ended September 30, 2007, respectively, and $(0.6) million and $0.1 million for the three and nine months ended September 30, 2006, respectively, are recorded in gain (loss) on interest rate swaps in the condensed consolidated statements of operations.

The following table presents the outstanding notional amounts and maximum number of months outstanding of interest rate swaps:

	September 30, 2007	December 31, 2006
	(in thousands, except months)	
Notional amount	$ 1,035,000	$ 50,000
Maximum number of months outstanding	39	12

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The following table presents the settlement terms of the interest rate swaps:

	Notional Amount (in thousands)	Fixed Rate
Settles monthly, October 2007 January 2008	$ 985,000	4.79%
Settles monthly, January 2008 January 2009	$ 985,000	4.25%
Settles monthly, January 2009 January 2011	$ 985,000	5.10%
Settles quarterly, October 2007 December 2007	$ 50,000	5.30%
Settles quarterly, January 2008 December 2008	$ 50,000	5.79%

(9) 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 purchasing, transportation and/or refining within the United States. 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 s customers consist primarily of major oil and gas purchasers and the Company generally does not require collateral.

A majority of the Company s largest customers are oil and gas refiners, suppliers and operators. For the three and nine months ended September 30, 2007, the Company s three largest customers represented approximately 24%, 18% and 18%, and 21%, 18% and 26%, respectively, of the Company s sales. 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.

At September 30, 2007, two customers trade accounts receivable from oil, gas and NGL sales accounted for more than 10% of the Company s total trade accounts receivable. At September 30, 2007, trade accounts receivable from these customers represented approximately 31% and 11% of the Company s receivables. At December 31, 2006, three customers trade accounts receivable from oil and gas sales accounted for more than 10% of the Company s total trade accounts receivable. As of December 31, 2006, trade accounts receivable from these customers represented approximately 41%, 22% and 16% of the Company s receivables.

(10) Commitments and Contingencies

The Company would have increased exposure to oil, gas and NGL price fluctuations on underlying sale contracts should the counterparties to the Company s derivative instruments or the counterparties to the Company s oil, gas and NGL marketing contracts not perform. Such non-performance is not anticipated. There were no counterparty default losses during the three or nine months ended September 30, 2007 or 2006.

In June 2007, the Company entered into an agreement and paid $0.4 million to cancel future lease obligations totaling $1.1 million related to an office facility in Pennsylvania.

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.

(11) Derivatives

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

Settled derivatives on gas production for the three and nine months ended September 30, 2007, included a volume of 5,762 MMMBtu and 15,131 MMMBtu at an average contract price of $8.51 and $8.46, respectively. Settled derivatives on oil and NGL production for the three and nine months ended September 30, 2007 included a volume of 500 MBbls and 1,392 MBbls at an average contract price of $68.71 and $69.00, respectively. The gas derivatives are settled based upon the closing NYMEX future price of gas or on the published PEPL spot price of gas on the settlement date, which occurs on the third day preceding the production month. The oil transactions are settled based upon the average month s daily NYMEX price of light oil and settlement occurs on the final day of the production month.

The following tables summarize open positions as of September 30, 2007 and represent, as of such date, derivatives in place through December 31, 2012, on annual production volumes:

	Year 2007	Year 2008	Year 2009	Year 2010	Year 2011	Year 2012
Gas Positions						
Fixed Price Swaps:						
Hedged Volume (MMMBtu)	9,689	49,410	49,271	42,086	38,741	34,066
Average Price ($/MMBtu)	$ 7.84	$ 7.79	$ 7.65	$ 7.48	$ 7.43	$ 7.50
Puts:						
Hedged Volume (MMMBtu)		10,907	12,294	17,594	20,219	5,934
Average Price ($/MMBtu)	$	$ 7.99	$ 7.65	$ 7.71	$ 7.73	$ 7.85
Total:						
Hedged Volume (MMMBtu)	9,689	60,317	61,565	59,680	58,960	40,000
Average Price ($/MMBtu)	$ 7.84	$ 7.82	$ 7.65	$ 7.55	$ 7.53	$ 7.55

	Year 2007	Year 2008	Year 2009	Year 2010	Year 2011	Year 2012
Oil Positions						
Fixed Price Swaps:						
Hedged Volume (MBbls)	308	1,542	1,587	1,300	1,223	800
Average Price ($/Bbl)	$ 74.15	$ 73.00	$ 72.89	$ 73.87	$ 68.23	$ 73.50
Puts:						
Hedged Volume (MBbls)	349	1,368	1,343	1,750	1,852	
Average Price ($/Bbl)	$ 66.17	$ 66.23	$ 66.06	$ 66.44	$ 65.57	$
Total:						
Hedged Volume (MBbls)	657	2,910	2,930	3,050	3,075	800
Average Price ($/Bbl)	$ 69.92	$ 69.82	$ 69.76	$ 69.61	$ 66.63	$ 73.50

Included in the table above are 39,016 of MMMBtu of gas that settle on the published PEPL spot price of gas, rather than NYMEX. The oil and gas derivatives are not designated as cash flow hedges under 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 oil and gas derivatives:

	September 30, 2007	**December 31, 2006**
Outstanding notional amounts of gas hedges (MMMBtu)	290,211	31,503
Maximum number of months gas hedges outstanding	63	35
Outstanding notional amounts of oil hedges (MBbls)	13,422	8,700
Maximum number of months oil hedges outstanding	64	60

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 credit-worthy counterparties.

(12) 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. 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* (SFAS 128). At September 30, 2007, the Company had two classes of units outstanding: (i) units representing limited liability company interests (units) listed on The NASDAQ Global Select Market under the symbol LINE and (ii) Class D units. See Note 3 for details regarding the Class D units.

In accordance with SFAS 128, dual presentation of basic and diluted earnings per unit has been presented in the condensed consolidated statements of operations for each class of units issued and outstanding at September 30, 2007, units and Class D units. Net income per unit is allocated to the units and the Class D units on an equal basis. Since the Class D units were converted to units on November 1, 2007, they share equally in the November 2007 distributions and all future distributions. The Company made no distributions to Class D unitholders during the period the Class D units were outstanding.

The following reconciliation presents the impact on the unit amounts of potential unit equivalents and the earnings per unit amounts:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands, except per unit amounts)			
Net income (loss)	$ (76,222)	$ 53,057	$ (161,195)	$ 85,273
Weighted average units outstanding:				
Basic units outstanding	69,207	27,584	58,072	27,118
Dilutive effect of unit equivalents and Class D units (1)		460		223
Diluted units outstanding	69,207	28,044	58,072	27,341
Weighted average Class D units outstanding:				
Basic Class D units outstanding	11,792		3,974	
Dilutive effect of unit equivalents				
Diluted Class D units outstanding	11,792		3,974	
Net income (loss) per unit:				
Units basic	$ (0.94)	$ 1.92	$ (2.60)	$ 3.14
Units diluted	$ (0.94)	$ 1.89	$ (2.60)	$ 3.12
Class D basic	$ (0.94)	$	$ (2.60)	$
Class D diluted	$ (0.94)	$	$ (2.60)	$

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(1) Excludes the effect of average anti-dilutive common stock equivalents related to unit options and warrants, and unvested restricted units of 547,197 and 441,154 for the three and nine months ended September 30, 2007, respectively. In addition, excludes the effect of average anti-dilutive Class D units for the three and nine months ended September 30, 2007. Excludes the effect of average anti-dilutive common stock equivalents related to unit options and unvested restricted units of 16,055 and 61,313 for the three and nine months ended September 30, 2006, respectively. All equivalent units are anti-dilutive for the three and nine months ended September 30, 2007 as the Company reported a net loss from operations.

(13) Unit-Based Compensation

Employee Grants

During the nine months ended September 30, 2007, the Company granted an aggregate 400,500 restricted units to employees as part of its annual review of employee compensation and 152,000 restricted units to new employees of the Company with an aggregate fair value of approximately $18.2 million. During the nine months ended September 30, 2007, the Company granted 123,000 unit options to new employees of the Company with a fair value of approximately $0.8 million. The majority of these restricted units and options vest ratably over three years. In addition, during the nine months ended September 30, 2007, the Company granted 12,000 phantom units to independent members of its Board of Directors with a fair value of approximately $0.4 million. The phantom units vest over one year.

For the three and nine months ended September 30, 2007, the Company recorded unit-based compensation expense of approximately $3.2 million and $9.5 million, respectively, as a charge against income before income taxes and it is included in general and administrative expenses on the condensed consolidated statements of operations. For the three and nine months ended September 30, 2006, the Company recorded unit-based compensation expense of approximately $4.2 million and $14.1 million, respectively.

Non-Employee Grants

In February 2007, the Company granted an aggregate 150,000 unit warrants to certain individuals in connection with a transition services agreement entered into with the Panhandle I acquisition (see Note 2). The unit warrants have an exercise price of $25.50 per unit warrant, may be exercised in whole or in-part on or after December 13, 2007, and expire ten years from issuance. In accordance with SFAS 123R, the Company computed the fair value of the unit warrants using the Black-Scholes model. At September 30, 2007, the aggregate fair value of the unit warrants was approximately $1.4 million and the expense was recognized over the five-month term of the agreement through June 30, 2007. For the nine months ended September 30, 2007, the Company recorded general and administrative expenses of approximately $1.4 million as a charge against income before income taxes.

(14) 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 passed through to the Company s 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 condensed consolidated 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 provisions of SFAS No. 109 *Accounting for Income Taxes* (SFAS 109), which uses 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. At September 30, 2007, deferred tax liabilities of approximately $1.3 million are recorded on the condensed consolidated balance sheets and deferred tax assets of $5.5 million, net of a valuation allowance of $4.2 million, are also recorded. At December 31, 2006, deferred tax liabilities of approximately $0.7 million are recorded on the condensed consolidated balance sheets and deferred tax assets of $6.3 million, net of a valuation allowance of $2.3 million, are also recorded.

The Company adopted Financial Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109* (FIN 48) on January 1, 2007. FIN 48 requires that the Company recognize only the impact of income tax positions that, based on their merits, are more likely than not to be sustained upon audit by a taxing authority. It also requires expanded financial statement disclosure of such positions.

In evaluating its current tax positions in order to identify any material uncertain tax positions, the Company developed a policy in identifying uncertain tax positions that considers support for each tax position, industry standards, tax return disclosures and schedules and the significance of each position. As of September 30, 2007, the Company had no material uncertain tax positions.

(15) Related Party Transactions

In September 2007, Quantum Energy Partners (Quantum) sold 4,620,000 of Linn units previously held. Subsequent to the sale, Quantum is no longer considered a related party to the Company as it owns less than 10% of total outstanding Linn units.

During the three and nine months ended September 30, 2006, the Company made payments of approximately $0.2 million and $0.4 million, respectively, to a company owned by one of its senior executives. The payments reflect reimbursement for maintenance and hourly usage fees for business use of an aircraft that was partially owned by the senior executive. These costs are included in general and administrative expenses on the condensed consolidated statements of operations. The fees and expenses associated with the reimbursements were consummated on terms equivalent to those that prevail in arm s-length 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 ended. Simultaneous with this transaction, the senior executive was able to fully liquidate the investment in the aircraft owned by his company.

At September 30, 2007, on an aggregate basis, a group of certain direct or indirect wholly-owned subsidiaries of Lehman Brothers Holding, Inc. (Lehman) owned over 10% of the Company s outstanding units, acquired during 2006 and 2007 in the Company s private placements of units (see Note 3). As such, Lehman is considered a related party under the provisions of SFAS No. 57 *Related Party Disclosures.* Lehman subsidiaries provide certain services to the Company, including participation in the Company s Credit Facility (see Note 6) and sale of commodity derivative instruments (see Note 11), which were all consummated on terms equivalent to those that prevail in arm s-length transactions.

In conjunction with its private placement of units, the Company received proceeds from Lehman of approximately $260.0 million and $378.7 million during the three and nine months ended September 30, 2007, respectively. The Company received such proceeds from Lehman of approximately $46.0 million during the three and nine months ended September 30, 2006.

During the three and nine months ended September 30, 2007, the Company paid Lehman underwriting fees of approximately $10.0 million and $13.5 million, respectively. In addition, during the three and nine months ended September 30, 2007, the Company paid distributions on units to Lehman of approximately $3.6 million and $7.5 million, respectively. During the three and nine months ended September 30, 2007, the Company paid Lehman approximately $204.1 million for oil and gas put and swap contracts. No similar payments were made during the comparable periods of 2006.

During the three and nine months ended September 30, 2007, the Company paid Lehman, through the administrator of its Credit Facility, interest on borrowings under its Credit Facility of approximately $0.3 million and $0.6 million, respectively, and financing fees of approximately $0.1 million. During the three and nine months ended September 30, 2006, the Company paid Lehman interest on borrowings under its Credit Facility of approximately $0.3 million and $0.4 million, respectively, and financing fees of approximately $30,000 and $42,000, respectively.

The following table sets forth the amounts due to or from Lehman as of the respective balance sheet dates included in the accompanying condensed consolidated financial statements:

	September 30, 2007		December 31, 2006	
	(in thousands)			
Assets:				
Current portion of oil and gas derivative assets	$	45,597	$	2,218
Long-term portion of oil and gas derivative assets	$	210,200	$	3,538
Liabilities:				
Current portion of oil and gas derivative liabilities	$	24,809	$	
Accrued interest payable Credit Facility	$	5,267	$	79
Credit Facility	$	36,400	$	15,966
Long-term portion of oil and gas derivative liabilities	$	101,405	$	

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

Executive Summary

Linn is an independent oil and gas company focused on providing stability and growth in distributions to its unitholders through continued successful drilling, acquisitions, increasing production of existing wells and pursuing operational and administrative efficiencies. The Company s oil, gas and NGL properties are currently located in three core areas:

Mid-Continent, which includes fields in Kansas, Oklahoma and Texas;

Appalachian Basin, which includes West Virginia, Pennsylvania and Virginia; and

Western, which includes the Brea Olinda Field of the Los Angeles Basin in California.

The following is a summary of the key elements of the Company s business strategy:

acquire properties that increase cash available for distributions;

build regional scale to maximize value and operating cash flows;

grow through low risk, low cost development drilling and other enhancements; and

mitigate commodity price and interest rate risk through hedging.

Certain key elements included in our business strategy are further explained below.

Acquire Properties and Build Regional Scale

The Company s acquisition program targets oil and gas properties that offer high-quality, long-life production with predictable decline curves, as well as development drilling opportunities. The following table provides a summary of significant acquisitions of working or royalty interests in oil and gas properties through the date of this report:

Year	# of Acquisitions	Gross Wells	Location		Aggregate Contract Price (in millions)
2003	4	498	West Virginia, Virginia, New York and Pennsylvania	$	52.0
2004	2	698	Pennsylvania		25.9
2005	3	718	West Virginia and Virginia		124.5
2006	5	1,430	West Virginia, California and Oklahoma		451.7
2007	7	4,929	West Virginia and Mid-Continent		2,668.9
	21	8,273		$	3,323.0

From inception through the date of this report, the Company has completed 21 significant acquisitions of working or royalty interests in oil and gas properties and related gathering and pipeline assets. Total proved reserves from working interests acquired were approximately 1.6 Tcfe, or an acquisition cost of approximately $2.07 per Mcfe. On August 31, 2007, the Company completed its largest acquisition to date, the Mid-Continent acquisition, acquiring oil and gas properties and other assets for approximately $2.0 billion and successfully recruited the 200 employees involved in operating the related acquired assets. See Note 2 in Notes to Condensed Consolidated Financial Statements for additional details about Company acquisitions during 2007.

Acquisitions are financed with a combination of proceeds from private placements of units, bank borrowings and cash flow from operations. The Company is focused on evaluating and developing its asset base, increasing acreage positions and evaluating potential acquisitions. Because of its rapid growth through acquisitions and development of properties, 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.

Growth Through Development Activities

The Company seeks to be the operator of its properties so that it can control the drilling programs that not only replace production, but add value through the growth of reserves and future operational synergies. Many of the Company s wells are completed in multiple producing zones with commingled production and long economic lives. Recent acquisitions provide an inventory of lower-risk development opportunities, which the Company expects will create post-acquisition value from our assets.

Drilling activity is concentrated on lower risk, development properties. The number, types, and location of wells the Company drills varies depending on its capital budget, the cost of each well, anticipated production and the estimated recoverable reserves attributable to each well. Historically, until 2007, most of the Company s drilling has been in the Appalachian Basin. With the February 2007 Panhandle I, June 2007 Panhandle II and August 2007 Mid-Continent acquisitions, the drilling program has been expanded to include the Texas Panhandle and the Oklahoma Anadarko Basin as well as other areas in the Mid-Continent.

Hedging Program

As noted above, the Company s revenues are highly sensitive to changes in oil, gas and NGL prices and levels of production. The Company typically seeks to hedge a significant portion of its anticipated future production volumes to reduce commodity price volatility risk. Managing this volatility, which is expected to continue in the future, provides a longer-term stability of cash flows. Currently, the Company uses fixed price swaps and puts to reduce its exposure to the volatility in oil, gas and NGL prices. As of the date of this report, the Company has hedged a significant portion of its expected production through 2012 using derivatives, which allows it to mitigate, but not eliminate, commodity price risk. See Note 11 in Notes to Condensed Consolidated Financial Statements for details about derivatives in place through December 31, 2012.

Risks

Revenues, cash flow from operations and future growth depend substantially on factors beyond the Company s control, such as economic, political and regulatory developments and competition from other producers. Oil, gas and NGL prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil, gas or NGL could materially and adversely affect the Company s financial position, results of operations, the quantities of productive reserves that can be economically produced and access to capital. See Cautionary Statement below in this Item 2. for additional information about risks related to Company.

Results of Operations - Three Months Ended September 30, 2007 Compared to Three Months Ended September 30, 2006

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Variance
	(in thousands)		
Revenues:			
Gas sales	$ 37,110	$ 15,553	$ 21,557
Oil sales	24,046	7,953	16,093
Natural gas liquid sales	13,906		13,906
Total oil, gas and natural gas liquid sales	75,062	23,506	51,556
Gain (loss) on oil and gas derivatives	(65,440)	57,396	(122,836)
Natural gas marketing revenues	8,434	1,090	7,344
Other revenues	423	265	158
Total revenues	$ 18,479	$ 82,257	$ (63,778)
Expenses:			
Operating expenses	$ 27,465	$ 4,845	$ 22,620
Natural gas marketing expenses	7,207	954	6,253
General and administrative expenses	13,202	6,536	6,666
Depreciation, depletion and amortization	24,320	5,654	18,666
Total expenses	$ 72,194	$ 17,989	$ 54,205
Other income and (expenses)	$ (22,186)	$ (11,211)	$ (10,975)

	Three Months Ended September 30, 2007		Three Months Ended September 30, 2006	Increase (Decrease)
Production:				
Gas production (MMcf)	6,770		2,265	198.9%
Oil production (MBbls)	345		153	125.5%
Natural gas liquid production (MBbls)	274			
Total production (MMcfe)	10,488		3,181	229.7%
Average daily production (MMcfe/d)	114.0		34.6	229.5%
Weighted average prices (hedged): (1)				
Gas (Mcf)	$ 7.57	$	10.27	(26.3)%
Oil (Bbl) (2)	$ 70.03	$	55.24	26.8%
Natural gas liquid (Bbl)	$ 50.75	$		
Total (Mcfe)	$ 8.51	$	9.97	(14.6)%
Weighted average prices (unhedged): (3)				
Gas (Mcf)	$ 5.48	$	6.87	(20.2)%
Oil (Bbl) (2)	$ 69.70	$	51.99	34.1%
Natural gas liquid (Bbl)	$ 50.75	$		
Total (Mcfe)	$ 7.16	$	7.39	(3.1)%
Average unit costs per Mcfe of production:				
Operating expenses	$ 2.62	$	1.52	72.4%
General and administrative expenses (4)	$ 1.26	$	2.05	(38.5)%
Depreciation, depletion and amortization	$ 2.32	$	1.78	30.3%

(1) Includes the effect of realized gains of $14.2 million and $8.2 million on derivatives for the three months ended September 30, 2007 and 2006, respectively.

(2) Oil production in California is sold pursuant to a long-term contract at 79% of NYMEX, and with gravity increase due to NGL being mixed into the oil stream, prices realized average approximately 82% of NYMEX.

(3) Does not include the effect of realized gains on derivatives.

(4) The measure for the three months ended September 30, 2007 and 2006 includes approximately $3.2 million and $4.2 million, respectively, of unit-based compensation expense. Excluding these amounts, general and administrative expenses for the three months ended September 30, 2007 and 2006 were $0.95 per Mcfe and $0.74 per Mcfe, respectively. This is a non-GAAP measure used by Company management to analyze its performance.

Revenues

Gas, oil and NGL sales increased 220%, to approximately $75.1 million for the three months ended September 30, 2007, from $23.5 million for the three months ended September 30, 2006.

The increase in revenue from gas, oil and NGL sales was primarily attributable to increased production. Total production increased to 10,488 MMcfe during the three months ended September 30, 2007, from 3,181 MMcfe during the three months ended September 30, 2006. The increase in production was due primarily to production from oil and gas properties acquired during 2007 and 2006 and by the drilling of new wells. The Company drilled 47 wells during the three months ended September 30, 2007, compared to 42 wells during the three months ended September 30, 2006.

Gas production increased to 6,770 MMcf during the three months ended September 30, 2007, from 2,265 MMcf during the three months ended September 30, 2006, with the 2007 acquisitions in the Mid-Continent core area contributing approximately 4,642 MMcf to current period gas production. The increase in production was slightly offset by a reduction in the weighted average gas price, from $6.87 per Mcf during the three months ended September 30, 2006, to $5.48 per Mcf during the comparable period of 2007, which caused gas revenues to decrease approximately $3.1 million.

Oil production increased to 345 MBbls during the three months ended September 30, 2007, from 153 MBbls during the during the three months ended September 30, 2006, due to the acquisitions in the Western and Mid-Continent core areas. The acquisitions in the Mid-Continent also increased NGL production to 274 MBbls during the three months ended September 30, 2007, from zero during the comparative period of the prior year. The increase in the weighted average price of oil for the period, from $51.99 per Bbl, to $69.70 per Bbl, also contributed slightly to the increase in oil revenues.

Hedging Activities

During the three months ended September 30, 2007, the Company had commodity pricing derivative contracts for approximately 69% of its third quarter gas production and 81% of its third quarter oil and NGL production, which resulted in realized gains of $14.2 million (revenues greater than would have been achieved at unhedged prices). During the three months ended September 30, 2006, the Company entered into commodity pricing derivative contracts for approximately 90% of its gas production and 26% of its oil production, which resulted in realized gains of $8.2 million. Unrealized losses on derivatives in the amount of $80.0 million for the three months ended September 30, 2007, and unrealized gains of $49.2 million for the three months ended September 30, 2006, were also recorded. Unrealized gains and losses result from changes in market valuations of derivatives as future commodity price expectations change compared to the contract price on the derivative.
During the quarter, short-term oil and gas prices increased, which reduced the market value of the derivatives. Such market value adjustment, if realized in the future, would be offset by higher actual prices for production. Since the Company has hedged a significant portion of its oil and gas production at fixed prices, it may not realize the benefit of future increases in commodity prices. See Note 11 in Notes to Condensed Consolidated Financial Statements for details regarding derivatives in place through December 31, 2012.

Expenses

Operating expenses include lease operating expenses, labor, field office expenses, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, and severance and ad valorem taxes. 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 reserves. The Company assesses its operating expenses by monitoring the expenses in relation to the amount of production and the number of wells operated. Operating expenses increased to $27.5 million for the three months ended September 30, 2007, from $4.8 million for the three months ended September 30, 2006, due primarily to expenses associated with the 2007 acquisitions in the Mid-Continent core area, including expenses associated with the addition of approximately 150 field and direct field support employees. In addition, the number of producing wells, which increased by over 4,000 gross wells as a result of the acquisitions completed in 2007 and the drilling of 47 wells in the three months ended September 30, 2007, and 519 wells from inception through September 30, 2007 also contributed to the increased operating expenses.

In addition, average operating expenses per equivalent unit of production increased to $2.62 for the three months ended September 30, 2007, compared to $1.52 for the three months ended September 30, 2006, due to increased material and labor costs and the changing mix of production beginning in the third quarter of 2006 to include oil and NGL, which have higher operating costs than gas wells. Operating expenses per Mcfe for the three months ended September 30, 2007 also increased due to turnover of purchased inventory valued at acquisition cost instead of cost to produce and increased ad valorem taxes due to higher property value assessments. Finally, the Company has incurred costs in 2007 for workover and maintenance of its wells to enhance future production and/or offset decline.

General and administrative expenses include the costs of employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. General and administrative expenses increased to approximately $13.2 million for the three months ended September 30, 2007, from $6.5 million for the three months ended September 30, 2006. The increase in general and administrative expenses was primarily due to costs incurred to support the Company s rapid growth through acquisitions and position the Company for future growth. In conjunction with expansion and development of the organization, to date during 2007, the Company has hired approximately 150 employees (including approximately 100 corporate, administrative and support employees with the Mid-Continent acquisition) and as a result, salaries and benefits expense increased approximately $4.1 million over the comparable quarter of 2006. Costs to perform the necessary functions associated with being a growing public company were $3.2 million during the third quarter of 2007, compared to $1.6 million during the third quarter of 2006. These costs include expenses for recruitment of key management team members, acquisition related data conversion and integration, public partnership tax reporting, audit fees, legal fees, proxy and printing costs and other professional fees, including costs related to compliance with Section 404 of the Sarbanes-Oxley Act of 2002 (Sarbanes-Oxley Act). The Company is currently in the process of implementing and testing procedures and controls in order to comply with the Sarbanes-Oxley Act at December 31, 2007, and as such, expects these costs to continue throughout the remainder of the year. 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 acquisition efforts that have not reached fruition, contributed to the increase. The increase in general and administrative expenses was partially offset by lower employee unit-based compensation expense, which decreased to $2.3 million (exclusive of amounts associated with certain of the new employees) during the three months ended September 30, 2007, from $4.2 million during the comparative quarter of 2006. Unit-based compensation expense incurred during the three months ended September 30, 2006 was higher compared to that incurred in the comparative period of 2007, primarily due to expense associated with unit awards granted in conjunction with the Company s IPO in January 2006. General and administrative expenses are presented net of approximately $0.1 million and $0.2 million during the three months ended September 30, 2007 and 2006, respectively, which represent expense reimbursements from other working interest owners.

Depreciation, depletion and amortization increased to approximately $24.3 million for the three months ended September 30, 2007, from $5.7 million for the three months ended September 30, 2006. Of this increase, approximately $3.8 million was as a result of depletion related to the Texas acquisitions in 2007. The properties acquired in the Mid-Continent acquisition contributed approximately $9.3 million to the increase. Although total depreciation, depletion and amortization increased in the third quarter of 2007 due to higher total production levels, the reserves in the acquired Texas, Oklahoma and California properties have lower depletion rates than the reserves in the Appalachian Basin. In addition, the depletion rate for oil and gas properties in the Appalachian Basin increased in the fourth quarter of 2006 due to a downward revision of estimated reserves from the prior year, primarily attributable to decreases in gas prices. During the three months ended September 30, 2007 and 2006, the Company capitalized approximately $3.0 million and $2.1 million, respectively, of costs for specific activities related to drilling its wells, which include site preparation, drilling labor, meter installation, pipeline connection and site reclamation. Capitalized drilling costs increased in the three months ended September 30, 2007 due to the Company s purchase and placement of two drilling rigs into service during the third quarter of 2006. Company personnel also perform activities using leased equipment, and did so prior to the purchase of its own rigs.

Other income and (expenses) increased to a net expense of $22.2 million for the three months ended September 30, 2007, compared to a net expense of $11.2 million for the three months ended September 30, 2006, primarily due to increased interest expense from increased debt levels associated with borrowings to fund the Mid-Continent acquisition and drilling. Cash payments for interest increased to $9.7 million for the three months ended September 30, 2007, compared to $8.5 million for the three months ended September 30, 2006. The Company s interest rate swaps (see Note 8 in Notes to Condensed Consolidated Financial Statements) were not designated as hedges under SFAS 133, even though they reduce exposure to changes in interest rates. Therefore, the changes in fair values of these instruments were recorded as losses of approximately $3.8 million and $0.6 million for the three months ended September 30, 2007 and 2006, respectively. These amounts are non-cash items.

Income tax was an expense of approximately $0.3 million for the three months ended September 30, 2007. There was no income tax impact recorded for the three months ended September 30, 2006. The Company s taxable subsidiaries generated net operating losses for the year ended December 31, 2006. Management has subsequently recovered expenses through an intercompany charge for services from Linn Operating, Inc. to Linn Energy, LLC, which resulted in a corresponding tax expense in the three months ended September 30, 2007. In addition, the three months ended September 30, 2007 includes Texas margin tax expense of $0.3 million.

Results of Operations - Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

	Nine Months Ended September 30, 2007	2006	Variance
		(in thousands)	
Revenues:			
Gas sales	$ 85,932	$ 44,727	$ 41,205
Oil sales	47,120	8,683	38,437
Natural gas liquid sales	30,431		30,431
Total oil, gas and natural gas liquid sales	163,483	53,410	110,073
Gain (loss) on oil and gas derivatives	(143,588)	94,537	(238,125)
Natural gas marketing revenues	11,351	3,654	7,697
Other revenues	3,652	758	2,894
Total revenues	$ 34,898	$ 152,359	$ (117,461)
Expenses:			
Operating expenses	$ 54,635	$ 10,772	$ 43,863
Natural gas marketing expenses	9,433	3,126	6,307
General and administrative expenses	36,360	22,934	13,426
Depreciation, depletion and amortization	49,109	13,470	35,639
Total expenses	$ 149,537	$ 50,302	$ 99,235
Other income and (expenses)	$ (42,573)	$ (16,858)	$ (25,715)

	Nine Months Ended September 30, 2007	2006	Increase (Decrease)
Production:			
Gas production (MMcf)	13,662	5,977	128.6%
Oil production (MBbls)	811	166	388.6%
Natural gas liquid production (MBbls)	604		
Total production (MMcfe)	22,157	6,973	217.8%
Average daily production (MMcfe/d)	81.2	25.5	218.4%
Weighted average prices (hedged): (1)			
Gas (Mcf)	$ 8.06	$ 10.30	(21.8)%
Oil (Bbl) (2)	$ 64.39	$ 55.31	16.4%
Natural gas liquid (Bbl)	$ 52.42	$	
Total (Mcfe)	$ 8.75	$ 10.15	(13.8)%
Weighted average prices (unhedged): (3)			
Gas (Mcf)	$ 6.29	$ 7.48	(15.9)%
Oil (Bbl) (2)	$ 58.10	$ 52.31	11.1%
Natural gas liquid (Bbl)	$ 50.38	$	
Total (Mcfe)	$ 7.38	$ 7.66	(3.7)%
Average unit costs per Mcfe of production:			
Operating expenses	$ 2.47	$ 1.54	60.4%
General and administrative expenses (4)	$ 1.64	$ 3.29	(50.2)%
Depreciation, depletion and amortization	$ 2.22	$ 1.93	15.0%

(1) Includes the effect of realized gains of $30.5 million and $17.4 million on derivatives for the nine months ended September 30, 2007 and 2006, respectively.

(2) Oil production in California is sold pursuant to a long-term contract at 79% of NYMEX, and with gravity increase due to NGL being mixed into the oil stream, prices realized average approximately 82% of NYMEX.

(3) Does not include the effect of realized gains on derivatives.

(4) The measure for the nine months ended September 30, 2007 and 2006 includes approximately $10.9 million and $14.1 million, respectively, of unit-based compensation expense and unit warrant expense. The measure for the nine months ended September 30, 2006 includes approximately $2.0 million of bonuses paid to certain executive officers in connection with the IPO. Excluding these amounts, general and administrative expenses for the nine months ended September 30, 2007 and 2006 were $1.15 per Mcfe and $0.98 per Mcfe, respectively. This is a non-GAAP measure used by Company management to analyze its performance.

Revenues

Gas, oil and NGL sales increased 206%, to approximately $163.5 million for the nine months ended September 30, 2007, from $53.4 million for the nine months ended September 30, 2006.

The increase in revenue from gas, oil and NGL sales was primarily attributable to increased production. Total production increased to 22,157 MMcfe during the nine months ended September 30, 2007, from 6,973 MMcfe during the nine months ended September 30, 2006. The increase in production was due primarily to production from oil and gas properties acquired during 2007 and 2006 and by the drilling of new wells. The Company drilled 160 wells during the nine months ended September 30, 2007, compared to 127 wells during the nine months ended September 30, 2006.

Gas production increased to 13,662 MMcf during the nine months ended September 30, 2007, from 5,977 MMcf during the nine months ended September 30, 2006, with the 2007 acquisitions in the Mid-Continent core area contributing approximately 7,372 MMcf to current period gas production. The increase in production was slightly offset by a reduction in the weighted average gas price, from $7.48 per Mcf during the nine months ended September 30, 2006, to $6.29 per Mcf during the comparable period of 2007, which caused gas revenues to decrease approximately $7.1 million.

Oil production increased to 811 MBbls during the nine months ended September 30, 2007, from 166 MBbls during the during the nine months ended September 30, 2006, due to the acquisitions in the Western and Mid-Continent core areas. The acquisitions in the Mid-Continent also increased NGL production to 604 MBbls during the nine months ended September 30, 2007, from zero during the comparative period of the prior year. The increase in the weighted average price of oil for the period, from $52.31 per Bbl, to $58.10 per Bbl, also contributed slightly to the increase in oil revenues.

Hedging Activities

During the nine months ended September 30, 2007, the Company had commodity pricing derivative contracts for approximately 97% of its nine month gas production and 97% of its nine month oil and NGL production, which resulted in realized gains of $30.5 million (revenues greater than would have been achieved at unhedged prices). The calculation of the percentage hedged for the nine months ended September 30, 2007 includes an adjustment to reflect Panhandle I production, which was hedged, but was not included in the Company s reported production. It was instead recorded as a purchase price adjustment (see Note 2 in Notes to Condensed Consolidated Financial Statements). During the nine months ended September 30, 2006, the Company entered into commodity pricing derivative contracts for approximately 102% of its gas production and 24% of its oil production, which resulted in realized gains of $17.4 million. Unrealized losses on derivatives in the amount of $174.1 million for the nine months ended September 30, 2007, and unrealized gains of $77.2 million for the nine months ended September 30, 2006, were also recorded. Unrealized gains and losses result from changes in market valuations of derivatives as future commodity price expectations change compared to the contract price on the derivative. During the nine months ended September 30, 2007, short-term oil and gas prices increased, which reduced the market value of the derivatives. Such market value adjustment, if realized in the future, would be offset by higher actual prices for production. Since the Company has hedged a significant portion of its oil and gas production at fixed prices, it may not realize the benefit of future increases in commodity prices. See Note 11 in Notes to Condensed Consolidated Financial Statements for details regarding derivatives in place through December 31, 2012.

Expenses

Operating expenses include lease operating expenses, labor, field office expenses, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, and severance and ad valorem taxes. 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 reserves. The Company assesses its operating expenses by monitoring the expenses in relation to the amount of production and the number of wells operated. Operating expenses increased to $54.6 million for the nine months ended September 30, 2007, from $10.8 million for the nine months ended September 30, 2006, due to the increase in the number of producing wells by over 4,000 gross wells as a result of the acquisitions completed in 2007 and the drilling of 160 wells in the nine months ended September 30, 2007, and 519 wells from inception through September 30, 2007. Expenses associated with the 2007 acquisitions in the Mid-Continent core area, including expenses associated with the addition of approximately 150 field and direct field support employees during the nine months ended September 30, 2007, also contributed to the increase in operating expenses.

In addition, average operating expenses per equivalent unit of production increased to $2.47 for the nine months ended September 30, 2007, compared to $1.54 for the nine months ended September 30, 2006, due to increased material and labor costs and the changing mix of production beginning in the third quarter of 2006 to include oil and NGL, which have higher operating costs than gas wells. Operating expenses per Mcfe for the nine months ended September 30, 2007 also increased due to turnover of purchased inventory valued at acquisition cost instead of cost to produce and increased ad valorem taxes due to higher property value assessments. Finally, the Company has incurred costs in 2007 for workover and maintenance of its wells to enhance future production and/or offset decline.

General and administrative expenses include the costs of employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. General and administrative expenses increased to approximately $36.4 million for the nine months ended September 30, 2007, from $22.9 million for the nine months ended September 30, 2006. The increase in general and administrative expenses was primarily due to costs incurred to support the Company s rapid growth through acquisitions and position the Company for future growth. In conjunction with expansion and development of the organization, to date during 2007, the Company has hired approximately 150 employees (including approximately 100 corporate, administrative and support employees with the Mid-Continent acquisition) and as a result, salaries and benefits expense increased approximately $7.0 million as compared to the nine months ended September 30, 2006. The Company also incurred approximately $1.8 million in expenses for services performed by third-parties pursuant to a transition services agreement associated with the Panhandle I properties (see Note 2 in Notes to Condensed Consolidated Financial Statements). This services agreement terminated effective June 30, 2007. Costs to perform the necessary functions associated with being a growing public company were $9.3 million during the nine months ended September 30, 2007, compared to $3.7 million during the nine months ended September 30, 2006. These costs include expenses for relocation of the Company headquarters from Pittsburgh, Pennsylvania to Houston, Texas, recruitment of key management team members, acquisition related data conversion and integration, public partnership tax reporting, audit fees, legal fees, proxy and printing costs and other professional fees, including costs related to compliance with the Sarbanes-Oxley Act. The Company is currently in the process of implementing and testing procedures and controls in order to comply with the Sarbanes-Oxley Act at December 31, 2007, and as such, expects these costs to continue throughout the remainder of the year. 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 acquisition efforts that have not reached fruition, contributed to the increase. The increase in general and administrative expenses was partially offset by lower employee unit-based compensation expense, which decreased to $7.3 million (exclusive of amounts associated with certain of the new employees) during the nine months ended September 30, 2007, from $14.1 million during the comparative period of 2006. Unit-based compensation expense incurred during the nine months ended September 30, 2006 was higher compared to that incurred in the comparative period of 2007, primarily due to expense associated with unit awards granted in conjunction with the Company s IPO in January 2006. In addition, IPO bonuses of $2.0 million were paid to certain executive officers during the nine months ended September 30, 2006. General and administrative expenses are presented net of approximately $0.4 million and $0.9 million during the nine months ended September 30, 2007 and 2006, respectively, which represent expense reimbursements from other working interest owners.

Depreciation, depletion and amortization increased to approximately $49.1 million for the nine months ended September 30, 2007, from $13.5 million for the nine months ended September 30, 2006. Of this increase, approximately $10.6 million was as a result of depletion related to the California and Oklahoma acquisitions in the third quarter of 2006 and the Texas acquisitions during 2007. The properties acquired in the Mid-Continent acquisition contributed approximately $9.3 million to the increase. Although total depreciation, depletion and amortization increased in the nine months ended September 30, 2007 due to higher total production levels, the reserves in the acquired Texas, Oklahoma and California properties have lower depletion rates than the reserves in the Appalachian Basin. During the nine months ended September 30, 2007 and 2006, the Company capitalized approximately $7.7 million and $4.0 million, respectively, of costs for specific activities related to drilling its wells, which include site preparation, drilling labor, meter installation, pipeline connection and site reclamation. Capitalized drilling costs increased in the nine months ended September 30, 2007 due to the Company s purchase and placement of two drilling rigs into service during the third quarter of 2006. Company personnel also perform activities using leased equipment, and did so prior to the purchase of its own rigs.

Other income and (expenses) increased to a net expense of $42.6 million for the nine months ended September 30, 2007, compared to a net expense of $16.9 million for the nine months ended September 30, 2006, primarily due to increased interest expense from increased debt levels associated with borrowings to fund acquisitions and drilling. Cash payments for interest increased to $29.3 million for the nine months ended September 30, 2007, compared to $13.6 million for the nine months ended September 30, 2006. The Company s interest rate swaps (see Note 8 in Notes to Condensed Consolidated Financial Statements) were not designated as hedges under SFAS 133, even though they reduce exposure to changes in interest rates. Therefore, the changes in fair values of these instruments were recorded as a loss of approximately $3.7 million and a gain of $0.1 million for the nine months ended September 30, 2007 and 2006, respectively. These amounts are non-cash items.

Income tax was an expense of approximately $4.0 million for the nine months ended September 30, 2007, compared to a benefit of $74,000 for the nine months ended September 30, 2006. The Company s taxable subsidiaries generated net operating losses for the year ended December 31, 2006. Management has subsequently recovered expenses through an intercompany charge for services from Linn Operating, Inc. to Linn Energy, LLC, which resulted in a corresponding tax expense in the nine months ended September 30, 2007. In addition, the nine months ended September 30, 2007 includes Texas margin tax expense of $0.4 million.

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, 2007, 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, 2006. The policies disclosed included the accounting for oil and gas properties, reserve quantities, revenue recognition, purchase accounting and derivative instruments.

Liquidity and Capital Resources

The Company has utilized public and private equity, proceeds from bank borrowings and cash flow from operations for capital resources and liquidity. To date, the primary use of capital has been for the acquisition and development of oil and gas properties. As the Company pursues growth, it continually monitors the capital resources available to meet future financial obligations and planned capital expenditures. The Company s future success in growing reserves and production will be highly dependent on the capital resources available and its success in drilling for or acquiring additional reserves. The Company actively reviews acquisition opportunities on an ongoing basis. If the Company were to make significant additional acquisitions for cash, it would need to borrow additional amounts under the Credit Facility, if available, or obtain additional debt or equity financing. The Credit Facility imposes certain restrictions on the Company s ability to obtain additional debt financing. Based upon current expectations, the Company believes liquidity and capital resources will be sufficient for the conduct of its business and operations.

Statements of Cash Flows Operating Activities

At September 30, 2007, the Company had cash and cash equivalents of approximately $33.6 million compared to $6.6 million at December 31, 2006.

Cash used by operating activities for the nine months ended September 30, 2007 was approximately $188.0 million, compared to cash provided by operating activities of $8.0 million for the nine months ended September 30, 2006. The decrease in cash provided by operating activities was primarily due to premiums paid for derivatives of approximately $257.1 million. These premiums relate to oil and gas put and swap contracts to hedge projected production through December 31, 2012.

Cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, gas and NGL prices. Oil, gas and NGL prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond the Company s control. Future cash flow from operations will depend on the Company s ability to maintain and increase production through its drilling program and acquisitions, as well as the prices received for production. The Company enters into derivative arrangements to reduce the impact of commodity price volatility on operations. Currently, the Company uses fixed price swaps and puts to reduce its exposure to the volatility in oil, gas and NGL prices. See Note 11 in Notes to Condensed Consolidated Financial Statements for details about derivatives in place through December 31, 2012.

Statements of Cash Flows Investing Activities

Cash used in investing activities was approximately $2.64 billion for the nine months ended September 30, 2007, compared to $509.1 million for the nine months ended September 30, 2006. The increase in cash used in investing activities was primarily due to an increase in acquisition activity during the nine months ended September 30, 2007, compared to the same period of the prior year.

The total cash used in investing activities for the nine months ended September 30, 2007 includes $2.03 billion for the Mid-Continent acquisition, $484.5 million for the Panhandle I and Panhandle II acquisitions and $38.6 million for the acquisitions of certain gas properties in West Virginia. See Note 2 in Notes to Condensed Consolidated Financial Statements for additional details. Other acquisitions, including acquisitions of additional working interests in current wells, were approximately $21.6 million and property, plant and equipment purchases were $12.5 million. The total for the nine months ended September 30, 2007 also includes $54.2 million for the drilling and development of oil and gas properties.

Statements of Cash Flows Financing Activities

Cash provided by financing activities was approximately $2.85 billion for the nine months ended September 30, 2007, compared to $491.8 million for the nine months ended September 30, 2006.

The Company recorded gross proceeds of $2.12 billion from three private placements of its units during the nine months ended September 30, 2007 (see below). The proceeds, net of expenses of approximately $34.3 million, were used to finance the Mid-Continent and Panhandle I acquisitions, the acquisitions of certain gas properties in West Virginia, and to repay indebtedness under the Company s Credit Facility. During the nine months ended September 30, 2007, total proceeds from borrowings under the Credit Facility were $1.14 billion and total payments on the Credit Facility were $263.8 million.

Distributions

Under the limited liability company agreement, Company unitholders are entitled to receive a quarterly distribution of available cash to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses. In January 2007, the Company s Board of Directors declared a distribution of $0.52 per unit with respect to the fourth quarter of 2006. The distribution totaled approximately $22.7 million and was paid in February 2007. In April 2007, the Company s Board of Directors declared a distribution of $0.52 per unit with respect to the first quarter of 2007. The distribution totaled approximately $30.0 million and was paid in May 2007. In July 2007, the Company s Board of Directors declared a distribution of $0.57 per unit with respect to the second quarter of 2007. The distribution totaled approximately $37.4 million and was paid in August 2007.

In October 2007, the Company s Board of Directors declared a distribution of $0.57 per unit with respect to the third quarter of 2007. The distribution will be paid in November 2007 to unitholders of record as of the close of business on November 2, 2007. As previously announced, management currently intends to recommend to the Board of Directors a further increase in the quarterly cash distribution to $0.63 per unit, or $2.52 per unit on an annualized basis, beginning with the distribution with respect to the fourth quarter of 2007.

August 2007 Private Placement

In August 2007, the Company closed its private placement of $1.5 billion of units to a group of institutional investors, consisting of 34,997,005 Class D units at a price of $30.97 per unit and 12,999,989 units at a price of $32.00 per unit. Proceeds, net of expenses, were $1.48 billion and were used to fund the Mid-Continent acquisition (see Note 2 in Notes to Condensed Consolidated Financial Statements).

The Class D units represent a class of equity securities that is entitled to a special quarterly distribution equal to 115% of the distribution received by the holders of units, has no voting rights other than as required by law and is subordinated to the units on dissolution and liquidation. In November 2007, at a special meeting of Linn unitholders, unitholders approved the one-for-one conversion of the Class D units into units. In connection with the August 2007 Private Placement, the Company agreed to file a Registration Statement with the SEC covering the units and the Class D units. See Liquidated Damages below for details regarding potential penalties that could be incurred by the Company in the event the Registration Statement is not declared effective by the SEC on or prior to February 12, 2008.

June 2007 Private Placement

In June 2007, the Company closed its private placement of $260.0 million of units to a group of institutional investors, consisting of 7,761,194 units at a price of $33.50 per unit. Proceeds, net of expenses, were $255.2 million and were used to repay indebtedness under the Company s Credit Facility. In connection with the June 2007 Private Placement, the Company agreed to file a Registration Statement with the SEC covering the units. As discussed below under February 2007 Private Placement and October 2006 Private Placement, the Company s Registration Statement on Form S-3, as amended, to register units issued in the October 2006 and February 2007 offerings, has not yet been declared effective by the SEC. Under the terms of the registration rights agreement with the purchasers in the June 2007 Private Placement, the Company cannot file a Registration Statement to register the units issued in the June 2007 Private Placement until the Registration Statement covering the units issued in the February 2007 and October 2006 Private Placements is declared effective. See Liquidated Damages below for details regarding potential penalties that could be incurred by the Company in the event the Registration Statement is not declared effective by the SEC on or prior to November 13, 2007.

February 2007 Private Placement

In February 2007, the Company closed its private placement of $360.0 million of units to a group of institutional investors, consisting of 7,465,946 Class C units at a price of $25.06 per unit, and 6,650,144 units at a price of $26.00 per unit. Proceeds, net of expenses, were $353.1 million and were used to finance the Panhandle I acquisition and the acquisitions of certain gas properties in West Virginia (see Note 2 in Notes to Condensed Consolidated Financial Statements).

The Class C units were converted into units on a one-for-one basis in April 2007. The Company filed a Registration Statement on Form S-3 with the SEC covering the units in September 2007 and Amendment No. 1 to Form S-3 in October 2007. Under the registration rights agreement, as amended, liquidated damages could become payable if the Registration Statement is not declared effective by the SEC on or prior to December 31, 2007. The Registration Statement, as amended, has not yet been declared effective by the SEC. See Liquidated Damages below.

October 2006 Private Placement

In connection with its October 2006 private placement of units and Class B units (Class B units were converted to units on a one-for-one basis in January 2007), the Company filed a Registration Statement on Form S-3 with the SEC covering the units in September 2007 and Amendment No. 1 to Form S-3 in October 2007. Under the registration rights agreement, as amended, liquidated damages could become payable if the Registration Statement is not declared effective by the SEC on or prior to December 31, 2007. The Registration Statement, as amended, has not yet been declared effective by the SEC. See Liquidated Damages below.

Liquidated Damages

The Company could be required to pay purchasers liquidated damages specified in the agreements pursuant to the October 2006, February 2007, June 2007 and August 2007 Private Placements in the event the registration effectiveness deadlines noted above are not achieved. The potential payments under the agreements are 0.25% of the gross proceeds for each 30 day period that the registration deadlines are not met, up through 90 days. Subsequent to 90 days, the potential payments would increase for each 30 day period, up to a maximum of 1.0% of the gross proceeds of each offering. As of the date of this report, based on the facts discussed in June 2007 Private Placement above, it is reasonably possible that the Company may be required to make some amount of such payments; however, the Company does not expect payments under these agreements to be material to the Company s financial position or results of operations.

Initial Public Offering

In the first quarter of 2006, the Company completed its initial public offering of 12,450,000 units representing limited liability company interests 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, $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.

Credit Facility

On August 31, 2007 the Company entered into a new $1.8 billion Credit Facility with an available borrowing base of $1.8 billion, of which $1.65 billion is conforming, and a maturity of August 2010. In connection with its new Credit Facility, the Company paid approximately $9.3 million in financing fees, which were deferred and are being amortized over the life of the Credit Facility. In addition, during the three and nine months ended September 30, 2007, the Company wrote off deferred financing fees related to its prior credit facility of approximately $2.2 million and $2.8 million, respectively. At October 31, 2007, the Company had $450.5 million available for borrowing under its Credit 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. The Company s obligations under the Credit Facility are secured by mortgages on its oil and gas properties as well as a pledge of all ownership interests in its operating subsidiaries. The Company is required to maintain the mortgages on properties representing at least 80% of its oil and gas properties. Additionally, the obligations under the Credit Facility are guaranteed by all of the Company s operating subsidiaries and may be guaranteed by any future subsidiaries.

At the Company s election, interest on borrowings under the Credit Facility is determined by reference to either LIBOR plus an applicable margin between 1.00% and 2.25% per annum or the ABR plus an applicable margin between 0% and 0.75% per annum. Interest is generally payable quarterly for ABR loans and at the applicable maturity date for LIBOR loans.

The Credit Facility contains various covenants, substantially similar to the prior credit facility, that limit the Company s ability to incur indebtedness, enter into interest rate swaps, grant certain liens, make certain loans, acquisitions, capital expenditures and investments, make distributions other than from available cash, merge or consolidate, or engage in certain asset dispositions, including a sale of all or substantially all of its assets. The Credit Facility also contains covenants, substantially similar to the prior credit facility, that require the Company to maintain specified financial ratios. The other terms and conditions of the Credit Facility are substantially similar to the prior credit facility.

Off-Balance Sheet Arrangements

At September 30, 2007, the Company did not have any off-balance sheet arrangements that have, or are reasonably likely to have, a material effect on its financial position or results of operations.

Contingencies

The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Commitments and Contractual Obligations

The following table summarizes, as of September 30, 2007, certain contractual obligations that are reflected in the condensed consolidated balance sheet and/or disclosed in the accompanying notes thereto:

		Payments Due			
Contractual Obligations	**Total**	**October 1 December 31, 2007**	**2008 2009**	**2010 2011**	**Thereafter**
			(in thousands)		
Long-term Debt Obligations:					
Long-term notes payable	$ 1,622	$ 159	$ 1,007	$ 154	$ 302
Credit Facility	1,302,000			1,302,000	
Interest on Credit Facility computed at 7.188%	265,166	23,397	187,176	54,593	
Operating Lease Obligations:					
Office and office equipment leases	13,783	552	4,166	4,321	4,744
Other Long-term Liabilities:					
Asset retirement obligation	27,124			103	27,021
Other:					
Derivative instruments (1)	167,664	5,324	79,540	66,215	16,585
Drilling and other contracts	33,045	12,453	20,144	448	
Total	$ 1,810,404	$ 41,885	$ 292,033	$ 1,427,834	$ 48,652

(1) Derivative instruments are presented on the condensed consolidated balance sheet on a gross basis. Amounts presented in the table above do not include offsetting derivative assets.

Non-GAAP Financial Measure

Adjusted EBITDA

The Company defines Adjusted EBITDA as net income (loss) plus:

- Net operating cash flow from acquisitions, effective date through closing date;
- Interest expense, net of amounts capitalized;
- Depreciation, depletion and amortization;
- Write-off of deferred financing fees and other;
- (Gain) loss on sale of assets;
- Accretion of asset retirement obligation;
- Unrealized (gain) loss on derivatives;
- Unit-based compensation and unit warrant expense;
- IPO cash bonuses; and
- Income tax provision.

Adjusted EBITDA is a significant performance metric used by Company management to indicate (prior to the establishment of any reserves by its Board of Directors) the cash distributions the Company expects to pay unitholders. Specifically, this financial measure indicates to investors whether or not the Company is generating cash flow at a level that can sustain or support an increase in its 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.

For the third quarter of 2007 as compared to the third quarter of 2006, Adjusted EBITDA increased 303%, from $25.1 million to $101.2 million. For the nine months ended September 30, 2007 as compared to the comparable period of the prior year, Adjusted EBITDA increased 208%, from $55.7 million to $171.4 million.

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

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands)			
Net income (loss)	$ (76,222)	$ 53,057	$ (161,195)	$ 85,273
Plus:				
Net operating cash flow from acquisitions, effective date through closing date	46,957		51,650	712
Interest expense, net of amounts capitalized	16,810	11,204	36,675	16,539
Depreciation, depletion and amortization	24,320	5,654	49,109	13,470
Write-off of deferred financing fees and other	2,235	161	2,784	664
(Gain) loss on sale of assets	18	(47)	(867)	
Accretion of asset retirement obligation	243	61	577	180
Unrealized (gain) loss on derivatives	83,364	(49,198)	177,765	(77,176)
Unit-based compensation and unit warrant expense	3,199	4,191	10,890	14,067
IPO cash bonuses				2,039
Income tax (benefit) provision (1)	321		3,983	(74)
Adjusted EBITDA	$ 101,245	$ 25,083	$ 171,371	$ 55,694

(1) The Company s taxable subsidiaries generated net operating losses for the year ended December 31, 2006. Management has subsequently recovered expenses through an intercompany charge for services from Linn Operating, Inc. to Linn Energy, LLC, which resulted in a corresponding tax expense for the nine months ended September 30, 2007.

As noted above, Adjusted EBITDA is non-GAAP performance measure used by Company management to indicate the cash distributions the Company expects to pay unitholders. On the condensed consolidated statements of cash flows, net cash used by operating activities for the nine months ended September 30, 2007, was approximately $188.0 million and includes approximately $257.1 million invested in derivatives. Net cash provided by operating activities for the nine months ended September 30, 2006, was approximately $8.0 million and includes $14.2 million invested in derivatives.

New Accounting Standards

There have been no accounting standards that materially affected the Company this period; however, see Note 14 in Notes to Condensed Consolidated Financial Statements for detail regarding FIN 48.

Cautionary Statement

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

- business strategy;
- acquisition strategy;
- financial strategy;
- drilling locations;
- oil, gas and NGL reserves;
- realized oil, gas and NGL 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 Company expectations, which reflect estimates and assumptions made by Company management. These estimates and assumptions reflect management s best judgment based on currently known market conditions and other factors. Although the Company believes such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties beyond its control. In addition, management s assumptions may prove to be inaccurate. The Company cautions that the forward-looking statements contained in this Quarterly Report on Form 10-Q are not guarantees of future performance, and it cannot assure any reader that such statements will be realized or the forward-looking statements or events will occur. Actual results may differ materially from those anticipated or implied in forward-looking statements due to factors listed in Item 1A. Risk Factors in the Company s Annual Report on Form 10-K for the year ended December 31, 2006, and elsewhere in the Annual Report and also in the Company s Quarterly Reports on Form 10-Q. The forward-looking statements speak only as of the date made, and other than as required by law, the Company undertakes 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 potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil, gas and NGL 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 the Company views and manages its ongoing market risk exposures. All of the Company s market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

The Company s major market risk exposure is in the pricing applicable to oil, gas and NGL production. Realized pricing is primarily driven by the spot market prices applicable to production and the prevailing price for oil, gas and NGL. Pricing for oil, gas and NGL production has been historically volatile and unpredictable, and this volatility is expected to continue in the future. The prices the Company receives for production depend on many factors outside of its control.

The Company enters into hedging arrangements with respect to a portion of its projected production through various transactions that hedge the future prices received. See Note 11 in Notes to Condensed Consolidated Financial Statements for additional details. These transactions may include price swaps whereby the Company will receive a fixed price for production and pay a variable market price to the contract counterparty. At the settlement date, the Company receives the excess, if any, of the fixed NYMEX or PEPL price floor over the floating rate. Additionally, the Company has put options for which it pays the counterparty the fair value at the purchase date. These hedging activities are intended to support commodity prices at targeted levels and to manage exposure to oil, gas and NGL price fluctuations. The Company does not hold or issue derivative instruments for speculative trading purposes.

At September 30, 2007, the fair value of hedges that settle during the next twelve months was an asset of approximately $73.5 million and a liability of approximately $30.8 million for a net asset of approximately $42.7 million, which the Company is owed by the counterparty. A 10% increase in the index oil and gas prices above the September 30, 2007 prices for the next twelve months would result in a reduction in the value of the hedges of approximately $90.1 million; conversely, a 10% decrease in the index oil and gas prices would result in an increase of approximately $82.7 million.

Interest Rate Risk

At September 30, 2007, the Company had long-term debt outstanding of $1.3 billion under its Credit Facility, which incurred interest at floating rates in accordance the Credit Facility agreement. See Note 6 in Notes to Condensed Consolidated Financial Statements for additional details about the Credit Facility. As of September 30, 2007, the interest rate based on LIBOR was approximately 7.188%. A 1% increase in LIBOR would result in an estimated $8.2 million increase in annual interest expense associated with the Credit Facility.

The Company has periodically entered into interest rate swap agreements to minimize the effect of fluctuations in interest rates. The Company is required to pay counterparties the difference between the contract s fixed rate and the actual rate if the actual rate is lower than the fixed rate and conversely, counterparties are required to pay the Company if the actual rate is higher than the fixed rate in the contract. See Note 8 in Notes to

Condensed Consolidated Financial Statements for additional details.

The following table presents the settlement terms of the interest rate swaps:

	Notional Amount (in thousands)	Fixed Rate
Settles monthly, October 2007 January 2008	$ 985,000	4.79%
Settles monthly, January 2008 January 2009	$ 985,000	4.25%
Settles monthly, January 2009 January 2011	$ 985,000	5.10%
Settles quarterly, October 2007 December 2007	$ 50,000	5.30%
Settles quarterly, January 2008 December 2008	$ 50,000	5.79%

Under the terms of the swap agreements, interest is based on LIBOR. A 1% change in LIBOR as of September 30, 2007 would result in an estimated $9.1 million change in annual expense associated with the interest swap agreements.

The Company did not designate the interest rate swap agreements as cash flow hedges under SFAS 133; therefore, the changes in fair value of these instruments, which are non-cash gains or losses, are recorded in current earnings.

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 Securities Exchange Act of 1934 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.

The Company carried out an evaluation under the supervision and with the participation of its management, including its Chief Executive Officer and Chief Financial Officer, of the effectiveness of its disclosure controls and procedures as of the end of the period covered by this report.

Due to the remediation status of our material weaknesses described below, our Chief Executive Officer and Chief Financial Officer continue to conclude that our disclosure controls and procedures were not effective as of September 30, 2007. We believe we have taken the necessary steps to address the matters related to the material weaknesses described below and we conclude that material weaknesses (i), (iii) and (iv) have been remediated. Regarding material weakness (ii), review controls, including controls over significant computations involving estimates and judgment, we believe that these internal controls have not been implemented and operational for a sufficient period of time to demonstrate they are effective and have thus not been remediated. We believe our condensed 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. 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 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. As noted above, we conclude that material weaknesses (i), (iii) and (iv) have been remediated and that material weakness (ii) has not been remediated.

Remediation activities. During 2006 and the first six months of 2007, Company management took the following steps to strengthen internal control over financial reporting:

1. Recruited an experienced accounting team with over 130 combined years of experience in oil and gas accounting and financial reporting.

2. Utilized outside consultants with extensive oil and gas financial reporting experience and augmented accounting resources to assist with required filings and documentation of reconciliations and procedures.

3. Developed accounting and reporting position papers for critical accounting policies involving judgment or application of complex accounting standards.

4. Performed additional analysis and other post-closing procedures to enable the preparation of accurate consolidated financial statements, including all required disclosures. In addition, implemented certain review and monitoring controls over account reconciliations, and analysis and post-closing procedures.

5. 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.

6. Implemented the use of disclosure checklists addressing the disclosure requirements under GAAP as well as the incremental financial and non-financial information required by SEC regulations.

7. Provided extensive training on the accounting software system to both new and established accounting personnel.

8. Strengthened controls over financially significant spreadsheets, including change, version, access, input/output and data controls.

9. Enhanced information technology (IT) controls, in areas including the general IT environment, access to programs and data and change management.

In addition, to further enhance controls, during the three months ended September 30, 2007, the following improvements were implemented:

1. Implemented a Disclosure Committee to ensure that information required to be disclosed in periodic reports filed with the SEC is recorded, processed, summarized and reported correctly and within the required time periods.

2. Expanded identification of key financial reporting controls and implemented the use of risk control matrices to monitor the effectiveness of key controls.

As noted above, we believe we have taken the necessary steps to address the matters related to the material weaknesses described above and we conclude that material weaknesses (i), (iii) and (iv) have been remediated. Regarding material weakness (ii), review controls, including controls over significant computations involving estimates and judgment, we believe that these internal controls have not been implemented and operational for a sufficient period of time to demonstrate they are effective and have thus not been remediated.

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

The items noted above constitute the changes in the Company s internal control over financial reporting, as defined in Rule 13(a)-15(f) under the Exchange Act, during the three months ended September 30, 2007, that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

As previously reported, the Company expects to continue to make changes in internal control over financial reporting during the periods prior to December 31, 2007 in connection with its compliance efforts under Section 404 of the Sarbanes-Oxley Act of 2002. As such, the Company will continue to assess the adequacy of 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, the factors that have materially changed from those reported in Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006 are presented below. These risk factors primarily relate to the new $1.8 billion Credit Facility we entered into in August 2007 and the addition of NGL to our revenue stream in the first quarter of 2007, in conjunction with our acquisition of properties in the Texas Panhandle. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

Risks Related to Our Business

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

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

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

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

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

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

We actively seek to acquire oil and gas properties. Acquisitions involve potential risks that could adversely impact our future growth and our ability to increase distributions.

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

- the risk that reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;

inaccurate assumptions about revenues and costs, including synergies;

significant increases in our indebtedness and working capital requirements;

an inability to transition and integrate successfully or timely the businesses we acquire;

an inability to integrate data systems successfully or timely;

the assumption of unknown liabilities;

limitations on rights to indemnity from the seller;

the diversion of management s attention from other business concerns;

increased demands on existing personnel and on our corporate structure;

customer or key employee losses at the acquired businesses; and

the failure to realize expected growth or profitability.

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

We have 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 October 31, 2007, we had approximately $1.35 billion outstanding under our Credit Facility (with additional borrowing capacity of approximately $450.5 million). As a result of our indebtedness, we will use a portion of our cash flow to pay interest 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 indebtedness 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 distributions. The Credit Facility restricts our ability to obtain additional financing, enter into interest rate swaps, 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, gas and NGL 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. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other 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, gas or NGL prices for prolonged periods and resulting decreases in our borrowing base may force us to reduce or suspend distributions to our unitholders.

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

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

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

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

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

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

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

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

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

No one can measure underground accumulations of oil, gas and NGL in an exact way. Reserve engineering requires subjective estimates of underground accumulations of oil, gas and NGL and assumptions concerning future oil, gas and NGL prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. An independent petroleum engineering firm prepares estimates of our proved reserves. Over time, our internal engineers may make material changes to reserve estimates taking into account the results of actual drilling and production. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, we make certain assumptions regarding future oil, gas and NGL prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil, gas and NGL attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil, gas and NGL we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated oil, gas and NGL reserves. We base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the day of estimate. Actual future net cash flows from our properties also will be affected by factors such as:

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

The timing of both our production and our incurrence of expenses in connection with the development and production of our properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor, required to be used pursuant to SFAS No. 69, *Disclosures about Oil and Gas Producing Activities* when calculating discounted future net cash flows, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

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

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

- our proved reserves;
- the level of oil, gas and NGL we are able to produce from existing wells;
- the prices at which we are able to sell our oil, gas and NGL; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our Credit Facility decrease as a result of lower oil, gas and NGL prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Our Credit Facility restricts our ability to obtain new financing.

If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our Credit Facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our development operations, which in turn could lead to a possible decline in our reserves, cash flow, and future distributions.

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

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

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

For the nine months ended September 30, 2007, Dominion Resources, Inc., Duke Energy Corporation and ConocoPhillips accounted for approximately 26%, 22% and 16%, respectively, of our total volumes, or 64% in the aggregate. For the year ended December 31, 2006, Dominion Resources, Inc. and ConocoPhillips accounted for approximately 53%, and 14%, respectively, of our total volumes, or 67% in the aggregate. To the extent these and other customers reduce the volumes of oil, gas or NGL that they purchase from us, our revenues and cash available for distribution could decline.

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

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

As a result of contractually required registrations of our units, a substantial amount of our units may be sold in the future, which could reduce the market price of our outstanding units.

We have agreed to register for sale approximately 94.6 million units held by certain investors and certain members of our management.

Our Registration Statement on Form S-3 filed in September 2007, as amended in October 2007 (the Form S-3), includes a total of 38,350,470 units comprising:

the units and the units underlying the Class B units issued in October 2006 that were requested by the holders to be registered;

the units and the units underlying the Class C units issued in February 2007 that were requested by the holders to be registered; and

units held by certain members of our management.

The Registration Statement, as amended, has not yet been declared effective by the SEC.

In addition to the units available for resale under the Form S-3, in June 2007, we completed a private offering to institutional investors of 7,761,194 units. We agreed to file a Registration Statement with the SEC covering the units. In accordance with the agreement, if the Registration Statement is not declared effective by the SEC by November 13, 2007, we could be required to pay purchasers liquidated damages as defined in the agreement. As noted above, the Form S-3 has not yet been declared effective by the SEC. We cannot file a Registration Statement to register the units issued in the June 2007 or August 2007 offerings until the Form S-3 is declared effective.

In August 2007, we completed a private offering to a group of institutional investors of 12,999,989 units and 34,997,005 newly created Class D units. We agreed to file a Registration Statement with the SEC covering the units and the units underlying the Class D units, which were converted into units on a one-for-one basis in November 2007. In accordance with the agreement, if the Registration Statement is not declared effective by the SEC by February 12, 2008, we could be required to pay purchasers liquidated damages as defined in the agreement.

If the institutional purchasers in the private placements discussed above 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

None not previously reported.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Item 6. Exhibits - Continued

Exhibit Number	Description
2.1	Amended and Restated Mid-Continent Onshore Package Purchase Agreement, dated August 30, 2007, between Dominion Exploration & Production, Inc., Dominion Oklahoma Texas Exploration & Production, Inc., LDNG Texas Holdings, LLC, and DEPI Texas Holdings, LLC, as Sellers, and Linn Energy, LLC, as Purchaser (incorporated herein by reference to Exhibit 2.1 to Current Report on Form 8-K filed on September 5, 2007)
3.1	Certificate of Formation of Linn Energy Holdings, LLC (now Linn Energy, LLC) (incorporated herein by reference to Exhibit 3.1 to Registration Statement on Form S-1 (File No. 333-125501) filed by Linn Energy, LLC on June 3, 2005)
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 Form S-1 filed on June 3, 2005)
3.3	Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC dated January 19, 2006 (incorporated herein by reference to Exhibit 3.3 to Annual Report on Form 10-K filed on March 30, 2007)
3.4	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC dated October 24, 2006 (incorporated herein by reference to Exhibit 3.3 to Annual Report on Form 10-K filed on March 30, 2007)
3.5	Amendment No. 2 to Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC dated February 1, 2007 (incorporated herein by reference to Exhibit 3.3 to Annual Report on Form 10-K filed on March 30, 2007)
3.6	Amendment No. 3 to Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC dated August 31, 2007 (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on September 5, 2007)
4.1	Form of specimen unit certificate for the units of Linn Energy, LLC (incorporated herein by reference to Exhibit 4.1 to Annual Report on Form 10-K filed on May 31, 2006)
10.1	Third Amended and Restated Credit Agreement dated August 31, 2007, among Linn Energy, LLC, as borrower, BNP Paribas, as administrative agent, and the agents and lenders party thereto (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on September 5, 2007)
10.2	Third Amended and Restated Guaranty and Pledge Agreement, dated August 31, 2007, among Linn Energy, LLC, the other obligors named therein and BNP Paribas, as administrative agent (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed on September 5, 2007)
10.3	Registration Rights Agreement, dated August 31, 2007 by and among Linn Energy, LLC and the Purchasers named therein (incorporated herein by reference to Exhibit 10.3 to Current Report on Form 8-K filed on September 5, 2007)
31.1	Section 302 Certification of Michael C. Linn, Chairman, President and Chief Executive Officer of Linn Energy, LLC
31.2	Section 302 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC
32.1	Section 906 Certification of Michael C. Linn, Chairman, President and Chief Executive Officer of Linn Energy, LLC
32.2	Section 906 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC

Filed herewith.

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 9, 2007

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