LINN ENERGY, LLC
Form 10-K
February 26, 2009

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

Form 10-K

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

For the fiscal year ended December 31, 2008

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

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 (I.R.S. Employer Identification No.)
600 Travis, Suite 5100 Houston, Texas (Address of principal executive offices)	77002 (Zip Code)

Registrant's telephone number, including area code
(281) 840-4000
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Units Representing Limited Liability Company Interests	The NASDAQ Stock Market LLC

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No x

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $2,717,556,563 on June 30, 2008, based on $24.85 per unit, the last reported sales price of the units on The NASDAQ Global Market on such date.

As of January 30, 2009, there were 114,025,866 units outstanding.

Documents Incorporated By Reference:

Certain information called for in Items 10, 11, 12, 13 and 14 of Part III are incorporated by reference from the registrant's definitive proxy statement for the annual meeting of unitholders to be held on May 5, 2009.

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GLOSSARY OF TERMS

As commonly used in the oil and gas industry and as used in this Annual Report on Form 10-K, 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.

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

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

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

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

MBbls/d. MBbls per day.

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.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcf/d. MMcf per day.

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. 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.

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.

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

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

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

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

Reservoir. A porous and permeable underground formation containing a natural accumulation of 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 there from. 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 of discounted future net cash flows. 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, future income tax expenses or depreciation, depletion and amortization; discounted using an annual discount rate of 10%.

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

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 resources. Resources that are considered less certain to be recovered than proved reserves. Unproved resources may be further sub-classified to denote progressively increasing uncertainty of recoverability.

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. Maintenance on a producing well to restore or increase production.

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Part I

Item 1. Business

This Annual Report on Form 10-K contains forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information see "Forward-Looking Statements" included at the end of this Item 1. "Business" and see also Item 1A. "Risk Factors."

References

When referring to Linn Energy, LLC ("Linn Energy" or the "Company"), the intent is to refer to Linn Energy and its consolidated subsidiaries as a whole or on an individual basis, depending on the context in which the statements are made.

A reference to a "Note" herein refers to the accompanying Notes to Consolidated Financial Statements contained in Part II. Item 8. "Financial Statements and Supplementary Data."

Overview

Linn Energy is an independent oil and gas company focused on the development and acquisition of long life properties which complement its asset profile in producing basins within the United States. Linn Energy began operations in March 2003 and completed its initial public offering ("IPO") in January 2006. The Company's properties are currently located in the Mid-Continent and California.

Proved reserves at December 31, 2008 were 1,660 Bcfe, of which approximately 51% were gas, 31% were oil and 18% were natural gas liquids ("NGL"). Approximately 68% were classified as proved developed, with a total standardized measure of discounted future net cash flows of $1.42 billion. At December 31, 2008, the Company operated 4,453, or 66%, of its 6,716 gross productive wells. Average proved reserves-to-production ratio, or average reserve life, is approximately 21 years.

Strategy

The Company's primary goal is to provide stability and growth of distributions for the long-term benefit of its unitholders. The following is a summary of the key elements of the Company's business strategy:

- efficiently operate and develop acquired properties;
- reduce cash flow volatility through commodity price and interest rate hedging; and
- grow through acquisition of long life, high quality properties.

The Company's business strategy is discussed in more detail below.

Efficiently Operate and Develop Acquired Properties

The Company has aligned the operation of its acquired properties into defined operating regions to minimize operating costs and maximize production and capital efficiency. The Company maintains a large inventory of drilling and optimization projects within each region to achieve organic growth from its capital development program. The Company seeks to be the operator of its properties so that it can develop drilling programs and optimization projects that not only replace production, but add value through reserve and production growth and future operational synergies. The development program is focused on lower risk, repeatable drilling opportunities to maintain and/or grow cash flow. Many of the wells are completed in multiple producing zones with commingled production and long economic lives. The number, types and location of wells drilled varies depending on the Company's capital budget, the cost of each well, anticipated production and the estimated recoverable reserves attributable to each well. In addition, the Company seeks to deliver attractive financial returns by leveraging its experienced workforce and scalable infrastructure. For 2009, the Company estimates its total drilling and development capital expenditures will be approximately $150.0 million. This estimate is under

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continuous review and is subject to on-going adjustment. The Company expects to fund these capital expenditures with cash flow from operations.

Reduce Cash Flow Volatility Through Commodity Price and Interest Rate Hedging

An important part of the Company's business strategy includes hedging a significant portion of its forecasted production to reduce exposure to fluctuations in the prices of oil, gas and NGL. By removing a significant portion of the price volatility associated with future oil, gas and NGL production, the Company expects to mitigate, but not eliminate, the potential effects of declining commodity prices on cash flows from operations for those periods. These transactions are in the form of swap contracts, collars and put options. A put option requires the Company to pay the counterparty a premium equal to the fair value of the option at the purchase date and receive from the counterparty the excess, if any, of the fixed floor over the floating market price. The Company has derivative contracts in place through 2014 covering a significant portion of forecasted production volumes through 2012 to provide long-term cash flow predictability to pay distributions, service debt and manage its business.

In addition, the Company enters into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates. Currently, the Company utilizes London Interbank Offered Rate ("LIBOR") swaps to convert the borrowing rate on indebtedness under its credit facility from a floating to fixed rate. At January 30, 2009, with the new interest rate swap contracts discussed below in "Recent Developments," the Company had swapped LIBOR on approximately 88% of debt outstanding under its credit facility at an average fixed rate of 3.80% through January 2014. For additional details about the Company's interest rate swap agreements and commodity derivative contracts, see Part II. Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk." See also Note 9 and Note 10.

Grow Through Acquisition of Long Life, High Quality Properties

The Company's acquisition program targets oil and gas properties which offer long life, high quality production with relatively predictable decline curves, as well as lower risk development opportunities. The Company evaluates acquisitions based on decline profile, reserve life, operational efficiency, field cash flow and development costs. As part of this strategy, the Company continually seeks to optimize its asset portfolio, including divestitures of non-core assets. This allows the Company to redeploy capital into projects to develop lower risk, long life and low decline properties which are better suited to its business strategy.

From inception through the date of this report, the Company has completed 25 acquisitions of working and royalty interests in oil and gas properties and related gathering and pipeline assets. Excluding the Appalachian Basin properties sold in July 2008 (discussed in "Asset Sales" below), total acquired proved reserves were approximately 1.7 Tcfe at an acquisition cost of approximately $2.17 per Mcfe. The Company finances acquisitions with a combination of proceeds from the issuance of its units, bank borrowings and cash flow from operations. See Note 3 for additional details about the Company's recent acquisitions.

Recent Developments

Asset Sales

During the fourth quarter of 2008, the Company completed a year-long portfolio optimization project. The Company carefully analyzed its asset base to determine which properties best fit the Linn Energy business model with high quality reserves and long life production. During 2008, the Company sold approximately $1.0 billion (contract price) of properties that were non-core to its business strategy, primarily due to high capital requirements and high decline characteristics. The Company strategically capitalized on opportunities to monetize Marcellus Shale acreage in the

Appalachian Basin, high-decline acreage in the Verden area in Oklahoma and Woodford Shale acreage in Oklahoma. A summary of these transactions is as follows:

- On July 1, 2008, the Company completed the sale of its interests in oil and gas properties located in the Appalachian Basin to XTO Energy, Inc. ("XTO") for a contract price of $600.0 million. The assets include approximately 197 Bcfe of proved reserves at December 31, 2007. Net proceeds were $566.5 million and

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the carrying value of net assets sold was $405.8 million, resulting in a gain on the sale of $160.7 million. The results of the Company's Appalachian Basin operations are classified as discontinued operations for all periods presented (see Note 2).

- On August 15, 2008, the Company completed the sale of certain properties in the Verden area in Oklahoma to Laredo Petroleum, Inc. ("Laredo") for a contract price of $185.0 million, subject to closing adjustments. The assets include approximately 50,000 net acres and 45 Bcfe of proved reserves at December 31, 2007. Net proceeds and the carrying value of net assets sold were $169.4 million.

- On December 4, 2008, the Company completed the sale of its deep rights in certain central Oklahoma acreage, which includes the Woodford Shale interval, to Devon Energy Production Company, LP ("Devon") for a contract price of $202.3 million, subject to closing adjustments. The sale included approximately 34,000 net acres and no producing reserves. Net proceeds were $153.2 million and the carrying value of net assets sold was $54.2 million, resulting in a gain on the sale of $99.0 million. In January 2009, certain post closing matters were resolved and the Company received additional proceeds of $11.5 million, which will be reported as a gain in the first quarter of 2009. Pending resolution of title issues, the Company estimates it may receive additional proceeds ranging from $12.0 million to $18.0 million during the first quarter of 2009.

Interest Rate Swap Restructuring

In January 2009, the Company amended and extended its interest rate swap portfolio. The Company canceled, in a cashless transaction, its existing interest rate swap agreements that settled at a fixed rate of 5.06% through 2011 (see Note 9) and entered into new agreements that settle at a fixed rate of 3.80% through 2014. See Note 8 for details about the Company's credit facility and senior notes. The following presents the settlement terms of the interest rate swaps:

	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014 (1)
			(dollars in thousands)			
Notional Amount	$ 1,250,000	$ 1,250,000	$ 1,250,000	$ 1,250,000	$ 1,250,000	$ 1,250,000
Fixed Rate	3.80%	3.80%	3.80%	3.80%	3.80%	3.80%

(1) Represents interest rate swaps that settle in January 2014.

Distributions

In January 2009, the Company's Board of Directors declared a cash distribution of $0.63 per unit with respect to the fourth quarter of 2008. The distribution totaled approximately $72.5 million and was paid on February 13, 2009 to unitholders of record as of the close of business on February 6, 2009.

Unit Repurchase Plan

In October 2008, the Board of Directors of the Company authorized the repurchase of up to $100.0 million of the Company's outstanding units. During the year ended December 31, 2008, 1,076,900 units were purchased at an average unit price of $12.09, for a total cost of approximately $13.0 million. All units were subsequently canceled. The Company may purchase units from time to time on the open market or in negotiated purchases. The timing and amounts of any such repurchases will be at the discretion of management, subject to market conditions and other factors, and will be in accordance with applicable securities laws and other legal requirements. The repurchase plan does not obligate the Company to acquire any specific number of units and may be discontinued at any time. Units are purchased at fair market value on the date of purchase.

Credit and Capital Market Disruptions

Multiple events during 2008 involving numerous financial institutions have effectively restricted current liquidity within the capital markets throughout the United States and around the world. Despite efforts by treasury and banking regulators in the United States, Europe and other nations to provide liquidity to the financial sector, capital

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markets currently remain constrained. To the extent the Company accesses credit or capital markets in the near term, its ability to obtain terms and pricing similar to its existing terms and pricing may be limited. During 2009, the Company plans to renegotiate its credit facility, which matures in August 2010. Entry into a new credit facility is expected to result in increased interest expense and there can be no assurance that the borrowing base will remain at the current level. In addition, the Company cannot be assured that counterparties to the Company's derivative contracts will be able to perform under these contracts. For additional information about these and other risk factors that could affect the Company, see Item 1A. "Risk Factors."

Operating Regions

The Company's properties are located in three regions in the United States:

- Mid-Continent Deep, which includes the Texas Panhandle Deep Granite Wash formation and deep formations in Oklahoma;
- Mid-Continent Shallow, which includes the Texas Panhandle Brown Dolomite formation and shallow formations in Oklahoma; and
- Western, which includes the Brea Olinda Field of the Los Angeles Basin in California.

Mid-Continent Deep

The Mid-Continent Deep region includes properties in the Deep Granite Wash formation in the Texas Panhandle, which produces at depths ranging from 8,900 feet to 16,000 feet, as well as properties in Oklahoma which produce at depths over 8,000 feet. Mid-Continent Deep proved reserves represented approximately 54% of total proved reserves at December 31, 2008, of which 69% were classified as proved developed reserves. This region produced 136 MMcfe/d, or 64%, of the Company's 2008 average daily production. During 2008, the Company invested approximately $218.3 million to drill in this region. During 2009, the Company anticipates spending approximately 70% of its total capital budget for development activities in the Mid-Continent Deep region.

Mid-Continent Shallow

The Mid-Continent Shallow region includes properties producing from the Brown Dolomite formation in the Texas Panhandle, which produces at depths of approximately 3,200 feet, as well as properties in Oklahoma which produce at depths under 8,000 feet. Mid-Continent Shallow proved reserves represented approximately 33% of total proved reserves at December 31, 2008, of which 60% were classified as proved developed reserves. This region produced 63 MMcfe/d, or 30%, of the Company's 2008 average daily production. During 2008, the Company invested approximately $70.7 million to drill in this region. During 2009, the Company anticipates spending approximately 25% of its total capital budget for development activities in the Mid-Continent Shallow region.

In order to more efficiently transport its gas in the Mid-Continent Deep and Mid-Continent Shallow regions to market, the Company owns and operates a network of gas gathering systems comprised of approximately 900 miles of pipeline and associated compression and metering facilities which connect to numerous sales outlets in the Texas Panhandle.

Western

The Western region consists of the Brea Olinda Field of the Los Angeles Basin in California. The Brea Olinda Field was discovered in 1880 and produces from the shallow Pliocene formation to the deeper Miocene formation. Western proved reserves represented approximately 13% of total proved reserves at December 31, 2008, of which 87% were classified as proved developed reserves. This region produced 13 MMcfe/d, or 6%, of the Company's 2008 average daily production. During 2008, the Company invested approximately $3.1 million to drill in this region. During 2009, the Company anticipates spending approximately 5% of its total capital budget for development activities in the Western region.

The Western region also includes the operation of a gas processing facility which processes produced gas from Company and third party wells. Processed gas is utilized to generate electricity which is used in the field to power equipment, resulting in reduced operating costs. Revenues are also generated from the sale of excess power.

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Drilling and Acreage

The following sets forth the wells drilled in the Mid-Continent Deep, Mid-Continent Shallow and Western operating regions during the periods indicated (“gross” refers to the total wells in which the Company had a working interest and “net” refers to gross wells multiplied by its working interest):

	Year Ended December 31, 2008	2007	2006
Gross wells:			
Productive	304	136	3
Non-productive	2	2	1
Total	306	138	4
Net development wells:			
Productive	189	112	1
Non-productive	1	2	1
Total	190	114	2
Net exploratory wells:			
Productive	—	—	—
Non-productive	—	—	—
Total	—	—	—

The total wells above exclude 45, 115 and 155 gross wells (45, 105 and 150 net wells) drilled in the Appalachian Basin during the years ended December 31, 2008, 2007 and 2006, respectively. The totals above do not include 23 and 25 lateral segments added to existing vertical wellbores in the Mid-Continent Shallow region during the years ended December 31, 2008 and 2007, respectively. At December 31, 2008, the Company had 7 gross (4 net) wells in process.

The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of oil, gas or NGL, regardless of whether they generate a reasonable rate of return.

The following sets forth information about the Company’s drilling locations and net acres of leasehold interests as of December 31, 2008:

	Total (1)
Proved undeveloped	1,259
Other locations	2,810
Total drilling locations	4,069
Leasehold interests – net acres (in thousands)	737

(1) Does not include optimization projects.

As shown in the table above, as of December 31, 2008, the Company had 1,259 proved undeveloped drilling locations (specific drilling locations as to which the independent engineering firm, DeGolyer and MacNaughton, assigned proved undeveloped reserves as of such date) and the Company had identified 2,810 additional unproved drilling locations (specific drilling locations as to which DeGolyer and MacNaughton has not assigned any proved reserves) on acreage that the Company has under existing leases. As successful development wells frequently result in the reclassification of adjacent lease acreage from unproved to proved, the Company expects that a significant number of its unproved drilling locations will be reclassified as proved drilling locations prior to the actual drilling of these locations.

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Productive Wells

The following table sets forth information relating to the productive wells in which the Company owned a working interest as of December 31, 2008. Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline or other connections to commence deliveries. "Gross" wells refers to the total number of producing wells in which the Company has an interest, and "net" wells refers to the sum of its fractional working interests owned in gross wells. The number of wells below does not include approximately 2,200 productive wells in which the Company owns a royalty interest only.

	Gas Wells		Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated (1)	1,969	1,647	2,484	2,271	4,453	3,918
Non-operated (2)	1,313	205	950	54	2,263	259
Total	3,282	1,852	3,434	2,325	6,716	4,177

(1) 10 operated wells had multiple completions at December 31, 2008.

(2) 3 non-operated wells had multiple completions at December 31, 2008.

Developed and Undeveloped Acreage

The following sets forth information as of December 31, 2008, relating to leasehold acreage:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
			(in thousands)			
Leasehold acreage	1,555	664	116	73	1,671	737

Production, Price and Cost History

The results of the Company's Appalachian Basin and Mid Atlantic Well Service, Inc. ("Mid Atlantic") operations are classified as discontinued operations for all periods presented (see Note 2). Unless otherwise indicated, results of operations information presented herein relates only to Linn Energy's continuing operations.

The Company's gas production is primarily sold under market sensitive price contracts, which typically sell at differentials to The New York Mercantile Exchange ("NYMEX") or Panhandle Eastern Pipeline ("PEPL") gas prices due to the Btu content and the proximity to major consuming markets. The Company's gas production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. By the terms of the percentage-of-proceeds contracts, the Company receives a percentage of the resale price received by the purchaser for sales of residual gas and NGL recovered after transportation and processing of gas. These purchasers sell the residual gas and NGL based primarily on spot market prices. Under percentage-of-index contracts, the price per MMBtu the Company receives for gas is tied to indexes published in Gas Daily or Inside FERC Gas Market Report. Although exact percentages vary daily, as of December 31, 2008, approximately 90% of the Company's gas and NGL production was sold under short-term contracts at market-sensitive or spot prices. At December 31, 2008, the Company had gas throughput delivery commitments under long-term contracts of approximately 5,797 MMcf, 2,102 MMcf, 1,045 MMcf and 784 MMcf for the years ended December 31, 2009, 2010, 2011 and 2012, respectively.

The Company's oil production is primarily sold under market sensitive percentage-of-index contracts and percentage-of-proceeds contracts and as of December 31, 2008, approximately 80% of its oil production was sold under short-term contracts. At December 31, 2008, the Company had no delivery commitments for oil production.

As discussed in the "Strategy" section above, the Company enters into derivative contracts in the form of swap contracts, collars and put options to reduce the impact of commodity price volatility on its cash flow from

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operations. By removing price volatility from a significant portion of its production, the Company has mitigated, but not eliminated, potential effects of fluctuating oil, gas and NGL prices on its cash flow from operations for those periods.

The following sets forth information regarding net production of oil, gas and NGL and certain price information for each of the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
Average daily production – continuing operations:			
Gas (MMcf/d)	124	51	2
Oil (MBbls/d)	9	3	1
NGL (MBbls/d)	6	3	
Total (MMcfe/d)	212	87	8
Average daily production – discontinued operations:			
Total (MMcfe/d)	12	24	22
Weighted average prices (hedged): (1)			
Gas (Mcf)	$ 8.42	$ 8.36	$
Oil (Bbl)	$ 80.92	$ 67.07	$
NGL (Bbl)	$ 57.86	$ 55.51	$
Weighted average prices (unhedged): (2)			
Gas (Mcf)	$ 7.39	$ 6.39	$ 5.99
Oil (Bbl)	$ 92.78	$ 66.44	$ 49.55
NGL (Bbl)	$ 57.86	$ 55.51	$
Representative NYMEX oil and gas prices:			
Gas (MMBtu)	$ 9.04	$ 6.86	$ 7.23
Oil (Bbl)	$ 99.65	$ 72.34	$ 66.21
Costs per Mcfe of production:			
Lease operating expenses	$ 1.49	$ 1.31	$ 2.36
Transportation expenses	$ 0.23	$ 0.17	$ 0.01
General and administrative expenses (3)	$ 1.00	$ 1.61	$ 13.61
Depreciation, depletion and amortization	$ 2.50	$ 2.16	$ 1.56
Taxes, other than income taxes	$ 0.79	$ 0.70	$ 0.09

(1) Includes the effect of realized gains of $9.4 million (excluding $81.4 million realized losses on canceled derivative contracts) and $37.3 million on derivatives for the years ended December 31, 2008 and 2007, respectively. During the year ended December 31, 2008, the Company canceled (before the contract settlement date) derivative contracts on estimated future gas production primarily associated with properties in the Appalachian Basin and Verden areas resulting in realized losses of $81.4 million. This information is not presented for the year ended December 31, 2006 because it is not meaningful due to the classification of Appalachian Basin results of operations in discontinued operations (see Note 2).

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

(3) General and administrative expenses for the years ended December 31, 2008, 2007 and 2006 includes approximately $14.6 million, $13.5 million and $21.6 million, respectively, of non-cash unit-based compensation and unit warrant expenses. General and administrative expenses for the year ended December 31, 2006 also includes $2.0 million of IPO bonuses paid to certain executive officers. Excluding these amounts, general and administrative expenses for the years ended December 31, 2008, 2007 and 2006 were $0.81 per Mcfe, $1.19 per Mcfe and $5.14 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company's performance.

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Reserve Data

Proved Reserves

Proved oil and gas reserves are the estimated quantities of oil, gas and NGL 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, but not escalations based on future conditions. For additional information regarding estimates of oil, gas and NGL reserves, including estimates of proved and proved developed reserves and the standardized measure of discounted future net cash flows see Supplemental Oil and Gas Data (Unaudited) in Item 8. “Financial Statements and Supplementary Data.”

The following presents estimated net proved oil, gas and NGL reserves and the standardized measure of discounted future net cash flows at December 31, 2008, 2007 and 2006, based on reserve reports prepared by independent engineers DeGolyer and MacNaughton. The standardized measure of discounted future net cash flows is not intended to represent the market value of estimated oil, gas and NGL reserves.

	December 31, 2008	2007	2006
Reserve data – continuing operations:			
Estimated net proved reserves:			
Gas (Bcf)	851	833	77
Oil (MMBbls)	84	55	30
NGL (MMBbls)	51	43	—
Total (Bcfe)	1,660	1,419	255
Proved developed (Bcfe)	1,134	1,024	195
Proved undeveloped (Bcfe)	526	395	60
Proved developed reserves as a % of total proved reserves	68%	72%	76%
Standardized measure of discounted future net cash flows (in millions)	$ 1,424	$ 3,175	$ 299
Reserve data – discontinued operations:			
Estimated net proved reserves:			
Gas (Bcf)	—	195	197
Oil (MMBbls)	—	1	1
Total (Bcfe)	—	197	199
Proved developed (Bcfe)	—	148	119
Proved undeveloped (Bcfe)	—	49	80
Proved developed reserves as a % of total proved reserves	—	75%	60%
Standardized measure of discounted future net cash flows (in millions)	$ —	$ 283	$ 254
Representative NYMEX oil and gas prices at period end:			
Gas (MMBtu)	$ 5.71	$ 6.80	$ 5.64
Oil (Bbl)	$ 39.22	$ 95.92	$ 61.05

The data in the above table are estimates. Oil and gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and gas that are ultimately recovered.

These reserve estimates are reviewed and approved by Company senior engineering staff and management, with final approval by its Chief Operating Officer. The process performed by the independent engineers to prepare reserve amounts included their estimation of reserve quantities, future producing rates, future net revenue and the present value of such future net revenue. The independent engineering firms also prepared estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent Securities and Exchange Commission ("SEC") staff interpretations and guidance. In the conduct of their preparation of the reserve estimates, the independent engineering firms did not independently verify the accuracy

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and completeness of information and data furnished by the Company with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of their work, something came to their attention which brought into question the validity or sufficiency of any such information or data, they did not rely on such information or data until they had satisfactorily resolved their questions relating thereto. Their estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions. The Company has not filed reserve estimates with any federal authority or agency, with the exception of the SEC, since the last fiscal year ended.

Future prices received for production may vary, perhaps significantly, from the prices assumed for the purposes of estimating the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows should not be construed as the market value of the reserves at the dates shown. The 10% discount factor required to be used pursuant to Statement of Financial Accounting Standards ("SFAS") No. 69, "Disclosures about Oil and Gas Producing Activities" ("SFAS 69") may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and gas industry. The standardized measure of discounted future net cash flows is materially affected by assumptions about the timing of future production, which may prove to be inaccurate.

Operational Overview

General

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.

Principal Customers

For the year ended December 31, 2008, sales of oil, gas and NGL to DCP Midstream Partners, LP, ConocoPhillips and Enbridge Energy accounted for approximately 23%, 12% and 11%, respectively, of the Company's total volumes, or 46% in the aggregate. If the Company were to lose any one of its major oil and gas purchasers, the loss could temporarily cease or delay production and sale of its oil and gas in that particular purchaser's service area. If the Company were to lose a purchaser, it believes it could identify a substitute purchaser. However, if one or more of these large gas purchasers ceased purchasing oil and gas altogether, it could have a detrimental effect on the oil and gas market in general and on the volume of oil and gas that it is able to sell.

Competition

The oil and gas industry is highly competitive. The Company encounters strong competition from other independent operators and master limited partnerships in acquiring properties, contracting for drilling and other related services and securing trained personnel. The Company is also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and has caused significant price increases. The Company is unable to predict when, or if, such shortages may occur or how they would affect its drilling program.

Operating Hazards and Insurance

The oil and gas industry involves a variety of operating hazards and risks that could result in substantial losses from, among other things, injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, cleanup responsibilities, regulatory investigation and penalties and suspension of operations.

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In addition, the Company may be liable for environmental damages caused by previous owners of property it purchases and leases. As a result, the Company may incur substantial liabilities to third parties or governmental entities, the payment of which could reduce or eliminate funds available for acquisitions, development or distributions, or result in the loss of properties.

In accordance with customary industry practices, the Company maintains insurance against some, but not all, potential losses. The Company cannot provide assurance that any insurance it obtains will be adequate to cover any losses or liabilities. The Company cannot predict the continued availability of insurance or the availability of insurance at premium levels that justify its purchase. The Company has elected to self-insure for trucks and vehicles licensed to operate on public highways and roads. The Company may elect to self-insure for additional items if it is determined that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on the Company's financial position and results of operations.

The Company participates in wells on a non-operated basis and therefore may be limited in its ability to control the risks associated with oil, gas and NGL operations.

Title to Properties

Prior to the commencement of drilling operations, the Company conducts a thorough title examination and performs curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, the Company is typically responsible for curing any title defects at its expense prior to commencing drilling operations. Prior to completing an acquisition of producing gas leases, the Company performs title reviews on the most significant leases and, depending on the materiality of properties, the Company may obtain a title opinion or review previously obtained title opinions. As a result, the Company has obtained title opinions on a significant portion of its oil and gas properties and believes that it has satisfactory title to its producing properties in accordance with standards generally accepted in the oil and gas industry. Oil and gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which do not materially interfere with the use of or affect the carrying value of the properties.

Seasonal Nature of Business

Seasonal weather conditions and lease stipulations can limit the drilling and producing activities and other operations in regions of the United States that the Company operates in. These seasonal conditions can pose challenges for meeting the well drilling objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, Company operations in all regions may be impacted by ice and snow in the winter and by electrical storms and high temperatures in the spring and summer, as well as by wild fires in the fall.

The demand for gas typically decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain gas users utilize gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand fluctuations. The demand for crude oil is generally determined at a global level, based on supply shortage concerns driven primarily by natural disasters such as hurricanes and by political instability in certain oil producing regions of the world.

Environmental Matters and Regulation

The Company's operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. The Company's operations are subject to the same environmental laws and regulations as other companies in the oil and gas industry. These laws and regulations may:

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment;

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- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from operations; and
- with respect to operations affecting federal lands or leases, require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement.

These laws, rules and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on operating costs.

The environmental laws and regulations applicable to the Company and its operations include, among others, the following United States federal laws and regulations:

- Clean Air Act, and its amendments, which governs air emissions;
- Clean Water Act, which governs discharges to waters of the United States;
- Comprehensive Environmental Response, Compensation and Liability Act, which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as “Superfund”);
- Energy Independence and Security Act of 2007, which prescribes new fuel economy standards and other energy saving measures;
- National Environmental Policy Act, which governs oil and gas production activities on federal lands;
- Resource Conservation and Recovery Act, which governs the management of solid waste;
- Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

Various states regulate the drilling for, and the production, gathering and sale of, oil and gas, including imposing production taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. States may regulate rates of production and may establish maximum daily production allowables from gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of oil, gas and NGL that may be produced from the Company’s wells and to limit the number of wells or locations it can drill. The oil and gas industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal opportunity employment.

The Company believes that it substantially complies with all current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on its financial condition or results of operations. Future regulations that could impact the Company include the Environmental Protection Agency’s proposed rule entitled Regulating Greenhouse Gas Emissions Under the Clean Air Act as well as a proposed “cap-and-trade” scheme for greenhouse gas emissions. The Company cannot predict how future environmental laws and regulations may impact its properties or operations. For the year ended December 31, 2008, the Company did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of the Company’s facilities. The Company is not aware of any environmental issues or claims that will require material capital expenditures during 2009 or that will otherwise have a material impact on its financial position or results of operations.

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Executive Officers of the Company

Name	Age	Position with the Company
Michael C. Linn	57	Chairman and Chief Executive Officer
Mark E. Ellis	53	President and Chief Operating Officer
Kolja Rockov	38	Executive Vice President and Chief Financial Officer
David B. Rottino	43	Senior Vice President and Chief Accounting Officer
Charlene A. Ripley	45	Senior Vice President, General Counsel and Corporate Secretary
Arden L. Walker, Jr.	49	Senior Vice President - Operations and Chief Engineer

Michael C. Linn is the Chairman and Chief Executive Officer of the Company and has served in such capacity since December 2007. Prior to that, from June 2006 to December 2007, Mr. Linn served as Chairman, President and Chief Executive Officer and from March 2003 to June 2006, he was the President, Chief Executive Officer and Director. From 2000 to 2003 Mr. Linn was President of Allegheny Interests, Inc., a private oil and gas investment company. From 1980 to 1999, Mr. Linn served as General Counsel (1980-1982), Vice President (1982-1987), President (1987-1990) and Chief Executive Officer (1990-1999) of Meridian Exploration, a private Appalachian Basin oil and gas company that was sold to Columbia Natural Resources in 1999. Both Allegheny Interests and Meridian Exploration were wholly owned by Mr. Linn and his family. Mr. Linn is the immediate past Chairman of the Independent Petroleum Association of America, the largest national trade association of independent oil and gas producers. He currently sits on the Boards of the National Petroleum Council, the American Exploration and Production Council and the National Association of Manufacturers and is a member of the oil and gas industry’s 25 Year Club. He was recently appointed as a Texas representative to the Legal and Regulatory Affairs Committee of the Interstate Oil and Gas Compact Commission. He is also Chairman of the Houston Wildcatters Committee of the Texas Alliance of Energy Producers. Mr. Linn regularly appears on behalf of the industry before state and federal agencies, such as the Department of Energy, Department of the Treasury, Federal Energy Regulatory Commission and the Environmental Protection Agency. In addition, he has testified on behalf of the industry before various committees and subcommittees of the U.S. House of Representatives and the U.S. Senate and is regularly quoted and has published various articles for trade publications and newspapers. He is also a frequent guest on radio and television programs representing the industry. Mr. Linn’s civic affiliations include memberships on the board of the Museum of Fine Arts Houston, as well as the board of Texas Heart Institute and Small Steps Nurturing Center. In addition, he is the Chairman of the Corporate Committee for Capital Campaign of Texas Children’s Hospital and serves on the Board of Trustees for Texas Children’s Hospital. He also serves on the Committee for the Bush-Clinton Coastal Recovery Fund.

Mark E. Ellis is the President and Chief Operating Officer and has served in such capacity since December 2007. From December 2006 to December 2007, Mr. Ellis was the Executive Vice President and Chief Operating Officer of the Company. Mr. Ellis has over 30 years of experience in the oil and gas industry, most recently serving as President, Lower 48 for ConocoPhillips from April 2006 to November 2006. Prior to joining ConocoPhillips, Mr. Ellis served as Senior Vice President of North American Production for Burlington Resources from September 2004 to April 2006. He served as President of Burlington Resources Canada Ltd. in Calgary from October 2000 to September 2004. Mr. Ellis joined Burlington Resources in 1985 and also held the positions of Vice President of the San Juan Division, Vice President and Chief Engineer and Manager of Acquisitions. He began his career at The Superior Oil Company, where he served in several engineering positions in the Onshore and Offshore divisions. Mr. Ellis is a member of the Society of Petroleum Engineers and a past board member of the New Mexico Oil & Gas Association, the Board of Governors of the Canadian Association of Petroleum Producers and served on the Foundation Board of the Alberta Children’s Hospital. Mr. Ellis currently serves on the Board of The Center for Hearing and Speech in Houston, Industry Board of Petroleum Engineering at Texas A&M University, the Visiting Committee of Petroleum Engineering at the Colorado School of Mines and the Houston Museum of Natural Science.

Kolja Rockov is the Executive Vice President and Chief Financial Officer. Mr. Rockov has over 15 years of experience in the oil and gas finance industry. From October 2004 until he joined Linn Energy in March 2005, Mr. Rockov served as a Managing Director in the Energy Group at RBC Capital Markets, where he was primarily responsible for investment banking coverage of the U.S. exploration and production sector. From September 2000 until October 2004, Mr. Rockov was a Director at RBC Capital Markets. Prior to September 2000, Mr. Rockov held various senior positions with Dain Rauscher Wessels and Rauscher Pierce Refsnes, Inc., predecessors of RBC Capital Markets.

David B. Rottino is the Senior Vice President and Chief Accounting Officer and has served in that position since June 2008. Mr. Rottino’s career includes over 15 years of oil and gas accounting experience, most recently serving as Vice President and E&P Controller for El Paso Corporation from June 2006 to May 2008. Prior to joining El Paso Corporation, Mr. Rottino served as Assistant Controller for ConocoPhillips from April 2006 to June 2006. He was Vice President and Chief Financial Officer for the Canadian division of Burlington Resources from July 2005 to April 2006 and served as Burlington Resources’ Director of Financial Analysis and Corporate Accounting from August 2000 to July 2005. Mr. Rottino joined Burlington Resources in 1996 and has served in a broad range of accounting and audit positions. Mr. Rottino is a Certified Public Accountant and a member of the American Institute of Certified Public Accountants and Texas Society of Certified Public Accountants. In addition, he currently serves on the Board of the June Rusche Hamrah Camp For All.

Charlene A. Ripley is the Senior Vice President, General Counsel and Corporate Secretary and has served in that position since April 2007. Prior to joining the Company, Ms. Ripley held the position of Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer at Anadarko Petroleum Corporation from 2006 until April 2007 and served as Vice President, General Counsel and Corporate Secretary from 2004 until 2006, Vice President and General Counsel from 2003 to 2004 and Vice President, General Counsel and Secretary of Anadarko Canada Corporation and its predecessor companies since 1998.

Arden L. Walker, Jr. is the Senior Vice President - Operations and Chief Engineer of the Company. Mr. Walker joined the Company in February 2007 to oversee its Western operations, which, at that time, included California, Oklahoma and Texas, and he is currently responsible for oversight of the Company’s operations in all regions. In addition, Mr. Walker serves in the capacity of chief engineer for the Company and is responsible for the Company’s reserve review and booking processes. From April 2006 until he joined the Company in February 2007, Mr. Walker served as Asset Development Manager, San Juan Business Unit for ConocoPhillips Company. From June 2004 to April 2006, Mr. Walker served as General Manager, Asset Development in San Juan Division for Burlington Resources. From January 2002 until June 2004, Mr. Walker served as Business Development Manager in San Juan Division for Burlington Resources. Mr. Walker began his career with El Paso Exploration Company in 1982 and has served in a broad range of engineering, business development and management positions with Burlington Resources since that time. Mr. Walker is a member of the Society of Petroleum Engineers, Independent Petroleum Association of America and California Independent Petroleum Association.

Employees

As of December 31, 2008, the Company employed approximately 505 personnel. None of the employees are represented by labor unions or covered by any collective bargaining agreement. The Company believes that its relationship with its employees is satisfactory.

Principal Executive Offices

The Company is a Delaware limited liability company with headquarters in Texas. The principal executive offices are located at 600 Travis, Suite 5100, Houston, Texas 77002. The main telephone number is (281) 840-4000.

Company Website

The Company's internet website is www.linnenergy.com. The Company makes available free of charge on or through its website Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the Company electronically files such material with, or furnishes it to, the SEC. Information on the Company's website should not be considered a part of, or incorporated by reference into, this Annual Report on Form 10-K.

The SEC maintains an internet website that contains these reports at www.sec.gov. Any materials that the Company files with the SEC may be read or copied at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information concerning the operation of the Public Reference Room may be obtained by calling the SEC at (800) 732-0330.

Forward-Looking Statements

This Annual Report on Form 10-K 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 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 Annual Report on Form 10-K, are forward-looking statements. These forward-looking statements may be found in Part I. Item 1. "Business;" Part I. Item 1A. "Risk Factors;" Part II. Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this Annual Report on Form 10-K. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "beli "estimate," "predict," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Annual Report on Form 10-K 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 Annual Report on

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Form 10-K 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 the "Risk Factors" section and elsewhere in this Annual Report on Form 10-K. 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.

Securities Act Disclaimer

This Form 10-K does not constitute an offer to sell or the solicitation of an offer to buy any securities.

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Item 1A. Risk Factors

Our business has many risks. Factors that could materially adversely affect our business, financial position, operating results or liquidity and the trading price of our units are described below. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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 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:

- produced volumes of oil, gas and NGL;
- prices at which oil, gas and NGL production is sold;
- level of our operating costs;
- payment of interest, which depends on the amount of our indebtedness and the interest payable thereon; and
- 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:

- availability of 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 or pay 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;
- the risk of title defects discovered after closing;
- 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;
- the cost of transition and integration of data systems and processes;
- the potential environmental problems and costs;

- 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;

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- customer or key employee losses of 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 or pay distributions.

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

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

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

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

We have significant indebtedness under our credit facility and senior notes. 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 and senior notes. As of January 30, 2009, we had an aggregate of approximately $1.43 billion outstanding under our credit facility and senior notes (with additional borrowing capacity of approximately $415.4 million). As a result of our indebtedness, we will use a portion of our cash flow to pay interest and principal when due, which will reduce the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate.

The credit facility restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We also are required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants could result in an event of default, which, if it continues beyond any applicable cure periods, could cause all of our existing indebtedness to be immediately due and payable.

We depend on our credit facility for future capital needs. We have drawn on our credit facility to fund or partially fund quarterly cash distribution payments, since we use operating cash flows for drilling and development of oil and gas properties and acquisitions and borrow as cash is needed. Absent such borrowing, we would have at times experienced a shortfall in cash available to pay our declared quarterly cash distribution amount. If there is an event of default by us under our credit facility that continues beyond any applicable cure period, we would be unable to make borrowings to fund distributions.

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. Significant declines in oil, gas or NGL prices may result in a decrease in our borrowing base. 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.

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Our ability to access the capital and credit markets to raise capital on favorable terms will be affected by our debt level and by disruptions in the capital and credit markets, which could adversely affect our operations and our ability to pay distributions to our unitholders.

The cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as some major financial institutions have consolidated and others may consolidate in the future, some lenders may increase interest rates, enact tighter lending standards, refuse to refinance existing debt at maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. If we are unable to refinance our credit facility on terms that are as favorable as those in our existing credit facility, or at all, our ability to fund our operations and our ability to pay distributions could be affected.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

Increases in interest rates could adversely affect the demand for our units.

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

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

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil, gas and NGL, we enter into commodity derivative contracts for a significant portion of our production. If we experience a sustained material interruption in our production or if we are unable to perform our drilling activity as planned, we might be forced to satisfy all or a portion of our derivative obligations without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction of our liquidity.

Disruptions in the capital and credit markets as a result of the global financial crisis may adversely affect our derivative positions.

We cannot be assured that our counterparties will be able to perform under our derivative contracts. If a counterparty fails to perform and the derivative arrangement is terminated, our cash flow, and ability to pay distributions could be impacted.

Commodity prices are volatile, and a significant decline in commodity prices for a prolonged period would reduce our revenues, cash flow from operations and profitability, and we may have to lower our distribution or may not be able to pay distributions at all.

Our revenue, profitability and cash flow depend upon the prices 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;
- the level of consumer product demand;
- weather conditions;

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- 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 would 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, gas and NGL 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 economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our 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. Independent petroleum engineering firms prepare estimates of our proved reserves. 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

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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. However, actual future net cash flows from our oil and gas 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;
- the timing and success of development activities;
- supply of and demand for oil, gas and NGL; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, required to be used pursuant to SFAS 69 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.

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

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

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomic if we drill dry holes or wells that are productive but do not produce enough oil, gas and NGL to be commercially viable after drilling, operating and other costs. If we drill

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future wells that we identify as dry holes, our drilling success rate would decline, which could have an adverse effect on our business, financial position or results of operations.

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 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 oil and gas 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 they purchase from us or delay payment, our revenues and cash available for distribution could decline. Further, a general increase in non-payment could have an adverse impact on our financial position and results of operations.

For the year ended December 31, 2008, DCP Midstream Partners, LP, ConocoPhillips and Enbridge Energy accounted for approximately 23%, 12% and 11%, respectively, of our total volumes from continuing operations, or 46% in the aggregate. For the year ended December 31, 2007, DCP Midstream Partners, LP and ConocoPhillips accounted for approximately 28% and 17%, respectively, of our total volumes from continuing operations, or 45% 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.

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

Our key project areas are located in some of the most active drilling areas of the producing basins in the United States. As a result, many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of reserves in these areas.

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

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2008, we had identified 4,069 drilling locations, of which 1,259 were proved undeveloped locations and 2,810 were other locations. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil, gas and NGL prices, costs and drilling results. In addition, DeGolyer and MacNaughton has not estimated proved reserves for the 2,810 other drilling locations we have identified and scheduled for drilling, and therefore there may be greater uncertainty with respect to the success of drilling wells at these drilling locations. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce oil, gas and NGL from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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

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

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

Any of these events can cause increased costs or restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling program or significant increase in costs could impact our ability to generate sufficient cash flow to pay quarterly distributions to our unitholders at the current distribution level. Increased costs could include losses from personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties. We ordinarily maintain insurance against certain losses and liabilities arising from our operations. However, it is impossible to insure against all operational risks in the course of our business. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial position and results of operations.

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

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

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

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

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

There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. For example, an accidental release from one of our wells or gathering pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover these costs from insurance. For a more detailed discussion of environmental and regulatory matters impacting our business, see Part I. Item 1. "Business - Environmental Matters and Regulation."

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

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

Part of the regulatory environment in which we operate includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil, gas and NGL we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to develop our properties. Additionally, the regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our ability to pay distributions to our unitholders. For a description of the laws and regulations that affect us, see Part I. Item 1. "Business - Environmental Matters and Regulation."

Our management may have conflicts of interest with the unitholders. Our limited liability company agreement limits the remedies available to our unitholders in the event unitholders have a claim relating to conflicts of interest.

Conflicts of interest may arise between our management on one hand, and the Company and our unitholders on the other hand, related to the divergent interests of our management. Situations in which the interests of our management may differ from interests of our non-affiliated unitholders include, among others, the following situations:

•

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

- our management team, subject to oversight from our Board of Directors, determines the timing and extent of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuances of

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additional membership interests and reserve adjustments, all of which will affect the amount of cash that we distribute to our unitholders; and

- affiliates of our directors are not prohibited from investing or engaging in other businesses or activities that compete with the Company.

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

Unlike a corporation, our limited liability company agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units may decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may have difficulty issuing more equity to recapitalize.

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

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

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

Current law or our business may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships and limited liability companies to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 0.7% of our total revenue apportioned to Texas in the prior year. Imposition of a tax on us by any other state would reduce the amount of cash available for distribution to our unitholders.

Unitholders may be subject to taxable gains upon dispositions of properties.

We may dispose of properties in transactions that result in gains that will be allocated to you, and such gains may be either ordinary gains or capital gains to you. Even where we dispose of properties that are capital assets, what otherwise would be capital gains to you may be recharacterized as ordinary gains in order to “recapture” ordinary deductions that were previously allocated to you related to the same properties. In addition, such an allocation of ordinary or capital gains may increase your taxable income, and you may be required to pay federal income taxes and state and local income taxes, even if we have not made a cash distribution to you subsequent to our disposal of the properties. Your allocable share of the taxable gains also may be greater than your interest in our profits. If you contributed property in exchange for our units, your capital account would have been credited with the fair market value of the property at the time (your "book" basis), which may have exceeded your "tax" basis of property. This could also be the case if you held our units at a time when we issued additional units to other unitholders (resulting in a revaluation of our assets). Gains are required to be allocated to you in order to eliminate this "book-tax disparity."

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Our unitholders may have more complex tax reporting and may be required to pay taxes on income even if they do not receive any cash distributions from us.

Our unitholders are required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income. Furthermore, distributions to unitholders in excess of the total net taxable income they were allocated, decreases their tax basis, which will become ordinary taxable income to them if the unit is later sold at a price greater than their tax basis, even if the price received is less than their original cost.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not reside in any of those jurisdictions. Our unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. In 2008, we have done business and owned assets in West Virginia, Virginia, Pennsylvania, New York, Virginia, California, Oklahoma, Kansas, New Mexico, Illinois, Indiana, Arkansas, Colorado, Kentucky, Louisiana, Mississippi, Montana, North Dakota, South Dakota and Texas. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all United States federal, state and local tax returns that may be required of such unitholder. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our units.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information concerning proved reserves, production, wells, acreage and related matters are contained in Part I. Item 1. "Business."

The Company's obligations under its credit facility are secured by mortgages on its oil and gas properties. See Part II. Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 8 for additional information concerning the credit facility.

Offices

The Company's principal corporate office is located at 600 Travis, Suite 5100, Houston, Texas 77002. The Company maintains additional offices in California, Illinois, Kansas, Louisiana, Oklahoma and Texas.

Item 3. Legal Proceedings

Although the Company may, from time to time, be involved in litigation and claims arising out of its operations in the normal course of business, the Company is not currently a party to any material legal proceedings. In addition, the Company is not aware of any material legal or governmental proceedings against it, or contemplated to be brought against it, under the various environmental protection statutes to which it is subject.

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

None.

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Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

The Company's units are listed on The NASDAQ Global Select Market ("NASDAQ") under the symbol "LINE" and began trading on January 13, 2006, after pricing of its initial public offering. At the close of business on January 30, 2009, there were approximately 280 unitholders of record.

The following presents the range of high and low last reported sales prices per unit, as reported by NASDAQ, for the quarters indicated. In addition, distributions declared during each quarter are presented.

Quarter	Unit Price Range High		Unit Price Range Low		Cash Distribution Declared Per Unit	
2008:						
October 1 – December 31	$	17.03	$	11.20	$	0.63
July 1 – September 30	$	24.88	$	14.93	$	0.63
April 1 – June 30	$	25.57	$	19.44	$	0.63
January 1 – March 31	$	24.41	$	18.88	$	0.63
2007:						
October 1 – December 31	$	30.79	$	22.88	$	0.57
July 1 – September 30	$	37.80	$	31.64	$	0.57
April 1 – June 30	$	39.61	$	32.47	$	0.52
January 1 – March 31	$	35.05	$	30.16	$	0.52

Distributions

The Company's limited liability company agreement requires it to make quarterly distributions to unitholders of all "available cash."

Available cash means, for each fiscal quarter, all cash on hand at the end of the quarter less the amount of cash reserves established by the Board of Directors to:

- provide for the proper conduct of business (including reserves for future capital expenditures, future debt service requirements, and for anticipated credit needs); and
- comply with applicable laws, debt instruments or other agreements;

plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

Working capital borrowings are borrowings that will be made under the Company's credit facility and in all cases are used solely for working capital purposes or to pay distributions to unitholders.

See Part II. Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" for a discussion on the payment of future distributions.

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Unitholder Return Performance Presentation

The performance graph below compares the total unitholder return on the Company's units, with the total return of the Standard & Poor's 500 Index (the "S&P 500 Index") and the Alerian MLP Index, a weighted composite of 50 prominent energy master limited partnerships. Total return includes the change in the market price, adjusted for reinvested dividends or distributions, for the period shown on the performance graph and assumes that $100 was invested in the Company at the last reported sale price of units as reported by NASDAQ ($22.00) on January 13, 2006 (the day trading of the units commenced), and in the S&P 500 Index and the Alerian MLP Index on the same date. The results shown in the graph below are not necessarily indicative of future performance.

	January 13, 2006	December 31, 2006	December 31, 2007	December 31, 2008
Linn Energy, LLC	$ 100	$ 153	$ 128	$ 87
Alerian MLP Index	$ 100	$ 120	$ 136	$ 86
S&P 500 Index	$ 100	$ 112	$ 118	$ 75

Notwithstanding anything to the contrary set forth in any of the Company's previous or future filings under the Securities Act of 1933 or the Securities Exchange Act of 1934 that might incorporate this Form 10-K or future filings with the SEC, in whole or in part, the preceding performance information shall not be deemed to be "soliciting material" or to be "filed" with the SEC or incorporated by reference into any filing except to the extent this performance presentation is specifically incorporated by reference therein.

Securities Authorized for Issuance Under Equity Compensation Plans

See the information incorporated by reference under Part III. Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" regarding securities authorized for issuance under the Company's equity compensation plans, which information is incorporated by reference into this Item 5.

Sales of Unregistered Securities

During the year ended December 31, 2008, the Company issued in private transactions: (i) 410,000 units in connection with the termination of certain contractual obligations (equal to a fair value of approximately $8.7 million) and (ii) 600,000 units in connection with the acquisition of certain gas properties (equal to a fair value of approximately $14.7 million). See Note 5 for additional details.

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Issuer Purchases of Equity Securities

The following sets forth information with respect to the Company with respect to repurchases of its units during the fourth quarter of 2008:

Period	Total Number of Units Purchased	Average Price Paid Per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Units that May Yet be Purchased Under the Plans or Programs (1) (in millions)
December 1 – December 31	1,076,900	$ 12.09	1,076,900	$ 87.0

(1) In October 2008, the Board of Directors of the Company authorized the repurchase of up to $100.0 million of the Company's outstanding units. The Company may purchase units from time to time on the open market or in negotiated purchases. The repurchase plan does not obligate the Company to acquire any specific number of units and may be discontinued at any time.

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Item 6. Selected Financial Data

The selected financial data set forth below should be read in conjunction with Part II. Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8. "Financial Statements and Supplementary Data."

Because of rapid growth through acquisitions and development of properties, the Company's historical results of operations and period-to-period comparisons of these results and certain other financial data may not be meaningful or indicative of future results. The results of the Company's Appalachian Basin and Mid Atlantic operations are classified as discontinued operations for all periods presented (see Note 2). Unless otherwise indicated, results of operations information presented herein relates only to Linn Energy's continuing operations.

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(in thousands, except per unit amounts)				
Statement of operations data:					
Oil, gas and natural gas liquid sales	$ 755,644	$ 255,927	$ 21,372	$	$
Gain (loss) on oil and gas derivatives	662,782	(345,537)	103,308	(76,193)	(11,004)
Depreciation, depletion and amortization	194,093	69,081	4,352		
Interest expense	94,517	38,974	5,909	481	124
Income (loss) from continuing operations	825,657	(356,194)	69,811	(79,311)	(12,665)
Income (loss) from discontinued operations, net of taxes (1)	173,959	(8,155)	9,374	22,960	7,849
Net income (loss)	999,616	(364,349)	79,185	(56,351)	(4,816)
Income (loss) from continuing operations per unit:					
Basic	7.23	(5.17)	2.33	(3.87)	(0.62)
Diluted	7.23	(5.17)	2.30	(3.87)	(0.62)
Income (loss) from discontinued operations per unit:					
Basic	1.53	(0.12)	0.31	1.12	0.39
Diluted	1.52	(0.12)	0.31	1.12	0.39
Net income (loss) per unit:					
Basic	8.76	(5.29)	2.64	(2.75)	(0.23)
Diluted	8.75	(5.29)	2.61	(2.75)	(0.23)
Distributions declared per unit	2.52	2.18	1.15		
Weighted average units outstanding	114,140	68,916	28,281	20,518	20,518
Cash flow data:					
Net cash provided by (used in):					
Operating activities (2)	$ 179,515	$ (44,814)	$ (6,805)	$ (29,518)	$ 10,351
Investing activities	(35,550)	(2,892,420)	(551,631)	(150,898)	(61,373)
Financing activities	(116,738)	2,932,080	553,990	189,269	31,167
Balance sheet data:					
Total assets	$ 4,722,020	$ 3,807,703	$ 905,912	$ 280,924	$ 105,425
Long-term debt	1,653,568	1,443,830	428,237	207,695	72,750
Unitholders' capital (deficit)	2,760,686	2,026,641	450,954	(46,831)	9,520

(1) Includes gain (loss) on sale of assets, net of taxes.

(2) Includes premiums paid for derivatives of approximately $129.5 million, $279.3 million, $49.8 million and $1.6 million for the years ended December 31, 2008, 2007, 2006 and 2005, respectively.

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	Year Ended December 31,				
	2008	2007	2006	2005	2004
Production data:					
Average daily production – continuing operations:					
Gas (MMcf/d)	124	51	2		
Oil (MBbls/d)	9	3	1		
NGL (MBbls/d)	6	3			
Total (MMcfe/d)	212	87	8		
Average daily production – discontinued operations:					
Total (MMcfe/d)	12	24	22	13	9
Estimated net proved reserves – continuing operations:					
Gas (Bcf)	851	833	77		
Oil (MMBbls)	84	55	30		
NGL (MMBbls)	51	43			
Total (Bcfe)	1,660	1,419	255		
Estimated net proved reserves – discontinued operations:					
Total (Bcfe)		197	199	193	120

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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with the "Selected Historical Consolidated Financial and Operating Data" and the financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion contains forward-looking statements that reflect the Company's future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside the Company's control. The Company's actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, gas and NGL, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in Part I. Item 1A. "Risk Factors." In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

A reference to a "Note" herein refers to the accompanying Notes to Consolidated Financial Statements contained in Item 8. "Financial Statements and Supplementary Data." Certain amounts in the results of operations contained herein have been reclassified to conform to the 2008 presentation. In particular, results of operations includes categories of expense titled "lease operating expenses," "transportation expenses," "exploration costs," "bad debt expenses," "impairment of goodwill and long-lived assets," "taxes, other than income taxes" and "(gain) loss on sale of assets, net" which were not reported in prior period presentations. The new categories present expenses in greater detail than was previously reported and all comparative periods presented have been reclassified to conform to the 2008 financial statement presentation. There was no impact to net income (loss) for prior periods.

Executive Overview

Linn Energy is an independent oil and gas company focused on the development and acquisition of long life properties which complement its asset profile in producing basins within the United States. The Company's properties are currently located in the Mid-Continent and California.

Proved reserves at December 31, 2008 were 1,660 Bcfe, of which approximately 51% were gas, 31% were oil and 18% were NGL. Approximately 68% were classified as proved developed, with a total standardized measure of discounted future net cash flows of $1.42 billion. At December 31, 2008, the Company operated 4,453, or 66%, of its 6,716 gross productive wells. Average proved reserves-to-production ratio, or average reserve life, is approximately 21 years.

From inception through the date of this report, the Company has completed 25 acquisitions of working and royalty interests in oil and gas properties and related gathering and pipeline assets. Excluding the Appalachian Basin properties sold in July 2008 (discussed below), total acquired proved reserves were approximately 1.7 Tcfe at an acquisition cost of approximately $2.17 per Mcfe. The Company finances acquisitions with a combination of proceeds from the issuance of its units, bank borrowings and cash flow from operations. See Note 3 for additional details about the Company's recent acquisitions.

On July 1, 2008, the Company completed the sale of its interests in oil and gas properties located in the Appalachian Basin to XTO for a contract price of $600.0 million, subject to closing adjustments (see Note 2). The assets include approximately 197 Bcfe of proved reserves at December 31, 2007. Net proceeds were $566.5 million and the carrying value of net assets sold was $405.8 million, resulting in a gain on the sale of $160.7 million, which is recorded in "discontinued operations: gain (loss) on sale of assets, net of taxes" on the consolidated statement of operations. The Company used the net proceeds from the sale to repay loans outstanding under its term loan agreement and reduce indebtedness under its credit facility (see Note 8). Also, in March 2008, the Company exited the drilling and service business in the Appalachian Basin provided by its wholly owned subsidiary Mid Atlantic. During the year ended December 31, 2008, the Company recorded a loss on the sale of the Mid Atlantic assets of $1.6 million, which is also recorded in “discontinued operations: gain (loss) on sale of assets, net of taxes” on the consolidated statement of operations.

The results of the Company’s Appalachian Basin and Mid Atlantic operations are classified as discontinued operations for all periods presented. Unless otherwise indicated, results of operations information presented herein relates only to Linn Energy’s continuing operations.

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Results from continuing operations for the year ended December 31, 2008 included the following:

- oil, gas and NGL sales of approximately $755.6 million, compared to $255.9 million in 2007;
- daily production of 212 MMcfe/d, compared to 87 MMcfe/d in 2007;
- capital expenditures of $321.3 million, excluding expenditures for acquisitions and discontinued operations;
- 306 wells drilled; and
- average of 11 operated drilling rigs.

Asset Sales

During the fourth quarter of 2008, the Company completed a year-long portfolio optimization project. The Company carefully analyzed its asset base to determine which properties best fit the Linn Energy business model with high quality reserves and long life production. During 2008, the Company sold approximately $1.0 billion (contract price) of properties that were non-core to its business strategy, primarily due to high capital requirements and high decline characteristics. The Appalachian Basin sale is discussed above. A summary of the other transactions is as follows:

- On August 15, 2008, the Company completed the sale of certain properties in the Verden area in Oklahoma to Laredo for a contract price of $185.0 million, subject to closing adjustments. The assets include approximately 50,000 net acres and 45 Bcfe of proved reserves at December 31, 2007. Net proceeds and the carrying value of net assets sold were $169.4 million. The Verden assets were acquired by the Company with its acquisition of oil and gas properties from Dominion in August 2007. The Company used the net proceeds from the sale to reduce indebtedness (see Note 8).

- On December 4, 2008, the Company completed the sale of its deep rights in certain central Oklahoma acreage, which includes the Woodford Shale interval, to Devon for a contract price of $202.3 million, subject to closing adjustments. The sale included approximately 34,000 net acres and no producing reserves. Linn Energy retains the rights to the shallow portion of this acreage. Net proceeds were $153.2 million and the carrying value of net assets sold was $54.2 million, resulting in a gain on the sale of $99.0 million, which is recorded in "(gain) loss on sale of assets, net" on the consolidated statement of operations. In January 2009, certain post closing matters were resolved and the Company received additional proceeds of $11.5 million, which will be reported as a gain in the first quarter of 2009. Pending resolution of title issues, the Company estimates it may receive additional proceeds ranging from $12.0 million to $18.0 million during the first quarter of 2009. These assets were acquired by the Company with its acquisition of oil and gas properties from Dominion in August 2007. The Company used the net proceeds from the sale to reduce indebtedness (see Note 8).

Unit Repurchase Plan

In October 2008, the Board of Directors of the Company authorized the repurchase of up to $100.0 million of the Company's outstanding units. During the year ended December 31, 2008, 1,076,900 units were purchased at an average unit price of $12.09, for a total cost of approximately $13.0 million. All units were subsequently canceled. The Company may purchase units from time to time on the open market or in negotiated purchases. The timing and amounts of any such repurchases will be at the discretion of management, subject to market conditions and other factors, and will be in accordance with applicable securities laws and other legal requirements. The repurchase plan does not obligate the Company to acquire any specific number of units and may be discontinued at any time. Units are purchased at fair market value on the date of purchase.

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Interest Rate Swap Restructuring

In January 2009, the Company amended and extended its interest rate swap portfolio. The Company canceled, in a cashless transaction, its existing interest rate swap agreements that settled at a fixed rate of 5.06% through 2011 (see Note 9) and entered into new agreements that settle at a fixed rate of 3.80% through 2014. See Note 8 for details about the Company's credit facility and senior notes. The following presents the settlement terms of the interest rate swaps:

	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014 (1)
	(dollars in thousands)					
Notional Amount	$ 1,250,000	$ 1,250,000	$ 1,250,000	$ 1,250,000	$ 1,250,000	$ 1,250,000
Fixed Rate	3.80%	3.80%	3.80%	3.80%	3.80%	3.80%

(1) Represents interest rate swaps that settle in January 2014.

Canceled Commodity Contracts

During the year ended December 31, 2008, the Company canceled (before the contract settlement date) derivative contracts on estimated future gas production resulting in realized losses of $81.4 million. The future gas production under the canceled contracts primarily related to properties in the Appalachian Basin and Verden areas (see Note 2). In addition, in September 2008, the Company canceled (before the contract settlement date) all of its commodity derivative contracts with Lehman Brothers Commodity Services Inc. (“Lehman Commodity Services”) as counterparty and entered into contracts for substantially the same volumes at identical strike prices with another participant in its credit facility for a cost of approximately $67.6 million. As a result, effective September 17, 2008, Lehman Commodity Services was no longer a counterparty to any of the Company’s commodity derivative contracts and the Company’s overall derivative positions are unchanged.

In September and October 2008, Lehman Brothers Holdings Inc. (“Lehman Holdings”) and Lehman Commodity Services, respectively, filed a voluntary petition for reorganization under Chapter 11 of the United States Bankruptcy Code (“Chapter 11”). As of December 31, 2008, the Company had a receivable of approximately $67.6 million from Lehman Commodity Services for canceled derivative contracts (see Note 13). The Company is pursuing various legal remedies to protect its interests. Based on market expectations, at December 31, 2008, the Company estimated approximately $6.7 million of the receivable balance to be collectible. The net receivable of approximately $6.7 million is included in “other current assets, net” on the consolidated balance sheet at December 31, 2008. The related expense is included in "gain (loss) on oil and gas derivatives" on the consolidated statement of operations for the year ended December 31, 2008. The Company believes that the ultimate disposition of this matter will not have a material adverse effect on its business, financial position, results of operations or liquidity.

Credit and Capital Market Disruption

Multiple events during 2008 involving numerous financial institutions have effectively restricted current liquidity within the capital markets throughout the United States and around the world. Despite efforts by treasury and banking regulators in the United States, Europe and other nations to provide liquidity to the financial sector, capital markets currently remain constrained. To the extent the Company accesses credit or capital markets in the near term, its ability to obtain terms and pricing similar to its existing terms and pricing may be limited. During 2009, the Company plans to renegotiate its credit facility, which matures in August 2010. Entry into a new credit facility is expected to result in increased interest expense and there can be no assurance that the borrowing base will remain at the current level. In addition, the Company cannot be assured that counterparties to the Company's derivative contracts will be able to perform under these contracts. For additional information about the Company's credit risk related to derivative contracts see "Fair Value of Financial Instruments" below. In addition, for information about these and other risk factors that could affect the Company, see Part I. Item 1A. "Risk Factors."

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Operating Regions

The Company's oil, gas and NGL properties are located in three regions in the United States:

- Mid-Continent Deep, which includes the Texas Panhandle Deep Granite Wash formation and deep formations in Oklahoma;
- Mid-Continent Shallow, which includes the Texas Panhandle Brown Dolomite formation and shallow formations in Oklahoma; and
- Western, which includes the Brea Olinda Field of the Los Angeles Basin in California.

Mid-Continent Deep

The Mid-Continent Deep region includes properties in the Deep Granite Wash formation in the Texas Panhandle, which produces at depths ranging from 8,900 feet to 16,000 feet, as well as properties in Oklahoma which produce at depths over 8,000 feet. Mid-Continent Deep proved reserves represented approximately 54% of total proved reserves at December 31, 2008, of which 69% were classified as proved developed reserves. This region produced 136 MMcfe/d, or 64%, of the Company's 2008 average daily production. During 2008, the Company invested approximately $218.3 million to drill in this region. During 2009, the Company anticipates spending approximately 70% of its total capital budget for development activities in the Mid-Continent Deep region.

Mid-Continent Shallow

The Mid-Continent Shallow region includes properties producing from the Brown Dolomite formation in the Texas Panhandle, which produces at depths of approximately 3,200 feet, as well as properties in Oklahoma which produce at depths under 8,000 feet. Mid-Continent Shallow proved reserves represented approximately 33% of total proved reserves at December 31, 2008, of which 60% were classified as proved developed reserves. This region produced 63 MMcfe/d, or 30%, of the Company's 2008 average daily production. During 2008, the Company invested approximately $70.7 million to drill in this region. During 2009, the Company anticipates spending approximately 25% of its total capital budget for development activities in the Mid-Continent Shallow region.

In order to more efficiently transport its gas in the Mid-Continent Deep and Mid-Continent Shallow regions to market, the Company owns and operates a network of gas gathering systems comprised of approximately 900 miles of pipeline and associated compression and metering facilities which connect to numerous sales outlets in the Texas Panhandle.

Western

The Western region consists of the Brea Olinda Field of the Los Angeles Basin in California. The Brea Olinda Field was discovered in 1880 and produces from the shallow Pliocene formation to the deeper Miocene formation. Western proved reserves represented approximately 13% of total proved reserves at December 31, 2008, of which 87% were classified as proved developed reserves. This region produced 13 MMcfe/d, or 6%, of the Company's 2008 average daily production. During 2008, the Company invested approximately $3.1 million to drill in this region. During 2009, the Company anticipates spending approximately 5% of its total capital budget for development activities in the Western region.

The Western region also includes the operation of a gas processing facility which processes produced gas from Company and third party wells. Processed gas is utilized to generate electricity which is used in the field to power equipment, resulting in reduced operating costs. Revenues are also generated from the sale of excess power.

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Results of Operations – Continuing Operations

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

	Year Ended December 31, 2008	2007	Variance
		(in thousands)	
Revenues and other:			
Gas sales	$ 334,214	$ 118,343	$ 215,871
Oil sales	291,132	82,523	208,609
NGL sales	130,298	55,061	75,237
Total oil, gas and NGL sales	755,644	255,927	499,717
Gain (loss) on oil and gas derivatives	662,782	(345,537)	1,008,319
Gas marketing revenues	12,846	11,589	1,257
Other revenues	3,759	2,738	1,021
	$ 1,435,031	$ (75,283)	$ 1,510,314
Expenses:			
Lease operating expenses	$ 115,402	$ 41,946	$ 73,456
Transportation expenses	17,597	5,575	12,022
Gas marketing expenses	11,070	9,100	1,970
General and administrative expenses (1)	77,391	51,374	26,017
Exploration costs	7,603	4,053	3,550
Bad debt expenses	1,436		1,436
Depreciation, depletion and amortization	194,093	69,081	125,012
Impairment of goodwill and long-lived assets	50,505		50,505
Taxes, other than income taxes	61,435	22,350	39,085
(Gain) loss on sale of assets, net	(98,763)	1,767	(100,530)
	$ 437,769	$ 205,246	$ 232,523
Other income and (expenses)	$ (168,893)	$ (70,877)	$ (98,016)
Income (loss) from continuing operations before income taxes	$ 828,369	$ (351,406)	$ 1,179,775

Notes to table:

(1) General and administrative expenses for the years ended December 31, 2008 and 2007 includes approximately $14.6 million and $13.5 million, respectively, of non-cash unit-based compensation and unit warrant expenses.

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	Year Ended December 31, 2008	2007	Variance
Average daily production – continuing operations:			
Gas (MMcf/d)	124	51	143%
Oil (MBbls/d)	9	3	200%
NGL (MBbls/d)	6	3	100%
Total (MMcfe/d)	212	87	144%
Average daily production – discontinued operations:			
Total (MMcfe/d)	12	24	(50)%
Weighted average prices (hedged): (1)			
Gas (Mcf)	$ 8.42	$ 8.36	1%
Oil (Bbl)	$ 80.92	$ 67.07	21%
NGL (Bbl)	$ 57.86	$ 55.51	4%
Weighted average prices (unhedged): (2)			
Gas (Mcf)	$ 7.39	$ 6.39	16%
Oil (Bbl)	$ 92.78	$ 66.44	40%
NGL (Bbl)	$ 57.86	$ 55.51	4%
Representative NYMEX oil and gas prices:			
Gas (MMBtu)	$ 9.04	$ 6.86	32%
Oil (Bbl)	$ 99.65	$ 72.34	38%
Costs per Mcfe of production:			
Lease operating expenses	$ 1.49	$ 1.31	14%
Transportation expenses	$ 0.23	$ 0.17	35%
General and administrative expenses (3)	$ 1.00	$ 1.61	(38)%
Depreciation, depletion and amortization	$ 2.50	$ 2.16	16%
Taxes, other than income taxes	$ 0.79	$ 0.70	13%

Notes to table:

(1) Includes the effect of realized gains of $9.4 million (excluding $81.4 million losses on canceled derivative contracts) and $37.3 million on derivatives for the years ended December 31, 2008 and 2007, respectively. During the year ended December 31, 2008, the Company canceled (before the contract settlement date) derivative contracts on estimated future gas production primarily associated with properties in the Appalachian Basin and Verden areas resulting in realized losses of $81.4 million.

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

(3) General and administrative expenses for the years ended December 31, 2008 and 2007 includes approximately $14.6 million and $13.5 million, respectively, of non-cash unit-based compensation and unit warrant expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2008 and 2007 were $0.81 per Mcfe and $1.19 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company’s performance.

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Revenues and Other

Oil, Gas and NGL Sales

Oil, gas and NGL sales increased by approximately $499.7 million, or 195%, to approximately $755.6 million for the year ended December 31, 2008, from $255.9 million for the year ended December 31, 2007.

The increase in oil, gas and NGL revenues was primarily attributable to increased production as a result of acquisitions and, to a lesser extent, drilling. Total production increased to 212 MMcfe/d during the year ended December 31, 2008, from 87 MMcfe/d during the year ended December 31, 2007. The increase in production was due primarily to the acquisition of oil and gas properties in the Mid-Continent Deep and Mid-Continent Shallow regions (see Note 3). In addition, the Company drilled 306 wells during the year ended December 31, 2008, compared to 138 wells during the year ended December 31, 2007. Volume increases during the year ended December 31, 2008 increased total oil, gas and NGL revenues by $366.3 million compared to the year ended December 31, 2007.

Gas production increased to 124 MMcf/d during the year ended December 31, 2008, from 51 MMcf/d during the year ended December 31, 2007, primarily due to the 2007 and 2008 acquisitions in the Mid-Continent Deep and Mid-Continent Shallow regions (see Note 3) and to drilling. The increase in the weighted average price of gas for 2008, to $7.39 per Mcf, from $6.39 per Mcf, contributed approximately $45.5 million to the increase in gas revenues.

Oil production increased to 9 MBbls/d during the year ended December 31, 2008, from 3 MBbls/d during the year ended December 31, 2007, due to acquisitions and the drilling of new wells. Acquisitions and drilling also increased NGL production to 6 MBbls/d during the year ended December 31, 2008, from 3 MBbls/d during the year ended December 31, 2007. The increase in the weighted average price of oil for 2008, to $92.78 per Bbl, from $66.44 per Bbl, contributed approximately $82.6 million to the increase in oil revenues. The increase in the weighted average price of NGL for 2008, to $57.86 per Bbl, from $55.51 per Bbl, contributed approximately $5.3 million to the increase in NGL revenues.

Gain (Loss) on Oil and Gas Derivatives

The Company determines the fair value of its oil and gas derivatives using pricing models that use a variety of techniques, including quotes and pricing analysis. See Note 9 and Note 10 for additional information and details regarding derivatives in place through December 31, 2014. During the year ended December 31, 2008, the Company had commodity derivative contracts for approximately 112% of its gas production and 82% of its oil and NGL production, which resulted in realized losses of $72.0 million. During the year ended December 31, 2008, the Company canceled (before the contract settlement date) derivative contracts on estimated future gas production primarily associated with properties in the Appalachian Basin and Verden areas (see Note 2) resulting in realized losses of $81.4 million. During the year ended December 31, 2007, the Company recorded realized gains of approximately $37.3 million. Unrealized gains and losses result from changes in market valuations of derivatives as future commodity price expectations change compared to the contract prices on the derivatives. During the second half of 2008, expected future oil and gas prices decreased, which resulted in unrealized gains on derivatives of approximately $734.7 million for the year ended December 31, 2008. During 2007, expected future oil and gas prices increased, which resulted in unrealized losses on derivatives of approximately $382.8 million for the year ended December 31, 2007. Market value adjustments, if realized in the future, would be offset by higher actual prices for production. For information about the Company’s credit risk related to derivative contracts see “Fair Value of Financial Instruments” below.

Expenses

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased by approximately $73.5 million, or 175%, to $115.4 million for the year ended December 31, 2008, from $41.9 million for the year ended December 31, 2007. Lease operating expenses increased primarily due to higher production and costs associated with the 2007 and 2008 acquisitions in the Mid-Continent Deep and Mid-Continent Shallow regions.

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Transportation Expenses

Transportation expenses increased by approximately $12.0 million, or 214%, to $17.6 million for the year ended December 31, 2008, from $5.6 million for the year ended December 31, 2007, primarily due to increased production from the 2007 and 2008 acquisitions in the Mid-Continent Deep and Mid-Continent Shallow regions.

General and Administrative Expenses

General and administrative expenses are costs not directly associated with field operations and include costs of employees and executive officers, related benefits, office leases and professional fees. As noted below, total general and administrative expenses increased; however, expenses per equivalent unit of production decreased to $1.00 per Mcfe for the year ended December 31, 2008, compared to $1.61 per Mcfe for the year ended December 31, 2007, due to increases in production, cost efficiencies and economies of scale provided by acquired properties.

General and administrative expenses increased by approximately $26.0 million, or 51%, to $77.4 million for the year ended December 31, 2008, from $51.4 million for the year ended December 31, 2007. The increase in general and administrative expenses over 2007 was primarily due to costs incurred to support the Company's increased size and infrastructure growth, including the addition of a regional operating office in Oklahoma. Salaries and benefits expense and employee unit-based compensation expense increased approximately $17.2 million and $2.5 million, respectively, during the year ended December 31, 2008 compared to the year ended December 31, 2007. Information technology costs, such as software, data administration and data conversion costs increased by approximately $3.6 million during the year ended December 31, 2008 compared to the year ended December 31, 2007. In addition, control of well insurance expense increased by approximately $2.7 million during the year ended December 31, 2008, primarily for properties in the Mid-Continent Deep region acquired in 2007 (see Note 3). The increase in general and administrative expenses was partially offset by lower professional service fees, unit warrant expenses and recovery of expenses under a transition services agreement with XTO (see Note 2).

Exploration Costs

Exploration costs increased by approximately $3.5 million, or 85%, to $7.6 million for the year ended December 31, 2008, from $4.1 million for the year ended December 31, 2007, primarily due to increased unproved leasehold costs associated with properties acquired in the Mid-Continent Deep region in August 2007.

Bad Debt Expenses

During the year ended December 31, 2008, the Company recorded bad debt expense of approximately $1.4 million associated with accounts receivable from a customer that filed a petition for reorganization under Chapter 11.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $125.0 million, or 181%, to $194.1 million for the year ended December 31, 2008, from $69.1 million for the year ended December 31, 2007. Higher total production levels, primarily due to the Company's acquisitions in the Mid-Continent Deep and Mid-Continent Shallow regions in 2008 and 2007, were the main reason for the increase. Depreciation, depletion and amortization per Mcfe increased to $2.50 per Mcfe for the year ended December 31, 2008, from $2.16 per Mcfe for the year ended December 31, 2007, primarily due to higher depletion rates on oil and gas properties acquired in the Mid-Continent Deep region in August 2007, as compared to the Company's other oil and gas properties.

Impairment of Goodwill and Long-Lived Assets

During the year ended December 31, 2008, the Company recorded impairment expense of approximately $50.5 million of which approximately $20.3 million is associated with impairment of goodwill and approximately $30.2 million is associated with impairment of oil and gas properties. See Note 1 and also "Critical Accounting Policies and Estimates" below for additional information.

Taxes, Other Than Income Taxes

Taxes, other than income taxes, which consists primarily of production and ad valorem taxes, increased by approximately $39.0 million, or 174%, to $61.4 million for the year ended December 31, 2008, from $22.4 million for the year ended December 31, 2007. Production and ad valorem taxes were approximately 8% of total sales for each of the years ended December 31, 2008 and 2007. Production taxes, which are a function of revenues generated from production, increased by approximately $32.4 million compared to the year ended December 31, 2007. Ad

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valorem taxes, which are based on the value of reserves and production equipment and vary by location, increased by approximately $6.9 million compared to 2007.

(Gain) Loss on Sale of Assets, Net

The increase in (gain) loss on sale of assets, net for the year ended December 31, 2008 is primarily due to a gain of $99.0 million from the sale of Woodford Shale assets in December 2008 (see Note 3).

Other Income and (Expenses)

Other income and (expenses) increased by approximately $98.0 million, to expense of $168.9 million for the year ended December 31, 2008, compared to expense of $70.9 million for the year ended December 31, 2007, primarily due to an increase in interest expense of approximately $55.5 million related to higher debt levels associated with borrowings to fund acquisitions and drilling. In addition, total losses on interest rate swaps increased by approximately $38.6 million over the year ended December 31, 2007. The Company's interest rate swaps were not designated as cash flow hedges under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, ("SFAS 133"), even though they reduce exposure to changes in interest rates (see Note 9). The changes in fair values of these instruments were recorded as unrealized losses of approximately $50.6 million and $29.5 million for the years ended December 31, 2008 and 2007, respectively. These amounts are non-cash items. Additionally, the Company wrote-off deferred financing fees of approximately $6.7 million during the year ended December 31, 2008, compared to approximately $2.8 million during the year ended December 31, 2007, which contributed to the increase in other income and (expenses).

Income Tax Benefit (Expense)

Income tax expense was approximately $2.7 million and $4.8 million for the years ended December 31, 2008 and 2007, respectively. Tax expense for the year ended December 31, 2008 primarily represents Texas margin tax expense. Limited liability companies are subject to state income taxes in Texas. The Company is treated as a partnership for federal and state income tax purposes; however, certain of the Company's subsidiaries are Subchapter C-corporations subject to federal and state income taxes. Tax expense for the year ended December 31, 2007 relates primarily to 2006 expense recovery. The Company's taxable subsidiaries generated net operating losses for the year ended December 31, 2006. During the year ended December 31, 2007, expenses were recovered by Linn Operating, Inc. through an intercompany charge for services to Linn Energy, which resulted in income tax expense for Linn Energy for the year ended December 31, 2007.

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Results of Operations – Continuing Operations

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

	Year Ended December 31, 2007	2006	Variance
		(in thousands)	
Revenues and other:			
Gas sales	$ 118,343	$ 4,475	$ 113,868
Oil sales	82,523	16,897	65,626
NGL sales	55,061		55,061
Total oil, gas and NGL sales	255,927	21,372	234,555
Gain (loss) on oil and gas derivatives	(345,537)	103,308	(448,845)
Gas marketing revenues	11,589		11,589
Other revenues	2,738	846	1,892
	$ (75,283)	$ 125,526	$ (200,809)
Expenses:			
Lease operating expenses	$ 41,946	$ 6,603	$ 35,343
Transportation expenses	5,575	40	5,535
Gas marketing expenses	9,100		9,100
General and administrative expenses (1)	51,374	37,997	13,377
Exploration costs	4,053	286	3,767
Bad debt expenses		12	(12)
Depreciation, depletion and amortization	69,081	4,352	64,729
Taxes, other than income taxes	22,350	243	22,107
(Gain) loss on sale of assets, net	1,767	28	1,739
	$ 205,246	$ 49,561	$ 155,685
Other income and (expenses)	$ (70,877)	$ (8,127)	$ (62,750)
Income (loss) from continuing operations before income taxes	$ (351,406)	$ 67,838	$ (419,244)

Notes to table:

(1) General and administrative expenses for the years ended December 31, 2007 and 2006 includes approximately $13.5 million and $21.6 million, respectively, of non-cash unit-based compensation and unit warrant expenses. General and administrative expenses for the year ended December 31, 2006 also includes $2.0 million of IPO bonuses paid to certain executive officers.

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	Year Ended December 31, 2007	2006	Variance
Average daily production – continuing operations:			
Gas (MMcf/d)	51	2	2,450%
Oil (MBbls/d)	3	1	200%
NGL (MBbls/d)	3		
Total (MMcfe/d)	87	8	988%
Average daily production – discontinued operations:			
Total (MMcfe/d)	24	22	9%
Weighted average prices (hedged): (1)			
Gas (Mcf)	$ 8.36	$	
Oil (Bbl)	$ 67.07	$	
NGL (Bbl)	$ 55.51	$	
Weighted average prices (unhedged): (2)			
Gas (Mcf)	$ 6.39	$ 5.99	7%
Oil (Bbl)	$ 66.44	$ 49.55	34%
NGL (Bbl)	$ 55.51	$	
Representative NYMEX oil and gas prices:			
Gas (MMBtu)	$ 6.86	$ 7.23	(5)%
Oil (Bbl)	$ 72.34	$ 66.21	9%
Costs per Mcfe of production:			
Lease operating expenses	$ 1.31	$ 2.36	(44)%
Transportation expenses	$ 0.17	$ 0.01	1,600%
General and administrative expenses (3)	$ 1.61	$ 13.61	(88)%
Depreciation, depletion and amortization	$ 2.16	$ 1.56	38%
Taxes, other than income taxes	$ 0.70	$ 0.09	678%

Notes to table:

(1) Includes the effect of realized gains of $37.3 million on derivatives for the year ended December 31, 2007. The data for the year ended December 31, 2006 is not presented because it is not meaningful due to the classification of Appalachian Basin results of operations in discontinued operations (see Note 2).

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

(3) General and administrative expenses for the years ended December 31, 2007 and 2006 includes approximately $13.5 million and $21.6 million, respectively, of non-cash unit-based compensation and unit warrant expenses. General and administrative expenses for the year ended December 31, 2006 also includes $2.0 million of IPO bonuses paid to certain executive officers. Excluding these amounts, general and administrative expenses for the years ended December 31, 2007 and 2006 were $1.19 per Mcfe and $5.14 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company’s performance.

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Revenues and Other

Oil, Gas and NGL Sales
Oil, gas and NGL sales increased by approximately $234.5 million, or 1,096%, to approximately $255.9 million for the year ended December 31, 2007, from $21.4 million for the year ended December 31, 2006.

The increase in oil, gas and NGL revenues was primarily attributable to increased production as a result of acquisitions and, to a lesser extent, drilling. Total production increased to 87 MMcfe/d during the year ended December 31, 2007, from 8 MMcfe/d during the year ended December 31, 2006. The increase in production was due primarily to production from oil and gas properties acquired in 2007 in the Mid-Continent Deep and Mid-Continent Shallow regions (see Note 3). In addition, the Company drilled 138 wells during the year ended December 31, 2007, compared to 4 wells during the year ended December 31, 2006. Volume increases during the year ended December 31, 2007 increased total oil, gas and NGL revenues by $206.2 million compared to the year ended December 31, 2006.

Gas production increased to 51 MMcf/d during the year ended December 31, 2007, from 2 MMcf/d during the year ended December 31, 2006, primarily due to acquisitions and drilling. The increase in the weighted average price of gas for 2007, to $6.39 per Mcf, from $5.99 per Mcf, contributed approximately $7.3 million to the increase in gas revenues.

Oil production increased to 3 MBbls/d during the year ended December 31, 2007, from 1 MBbls/d during the year ended December 31, 2006, due to acquisitions and drilling. Acquisitions and drilling also increased NGL production to 3 MBbls/d during the year ended December 31, 2007, from zero during the year ended December 31, 2006. The increase in the weighted average price of oil for 2007, to $66.44 per Bbl, from $49.55 per Bbl, contributed approximately $21.0 million to the increase in oil revenues.

Gain (Loss) on Oil and Gas Derivatives
During the years ended December 31, 2007 and 2006, the Company had commodity pricing derivative contracts for its oil, gas and NGL production, which resulted in realized gains of $37.3 million and $20.2 million, respectively. Unrealized losses on derivatives in the amount of $382.8 million for the year ended December 31, 2007, and unrealized gains of $83.1 million for the year ended December 31, 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 2007, expected future oil and gas prices increased, which reduced the market value of the derivatives. Market value adjustments, if realized in the future, would be offset by higher actual prices for production. See Note 9 for details regarding derivatives in place through December 31, 2014.

Expenses

Lease Operating Expenses
Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. As noted below, total lease operating expenses increased; however, lease operating expenses per equivalent unit of production decreased to $1.31 per Mcfe for the year ended December 31, 2007, compared to $2.36 per Mcfe for the year ended December 31, 2006, due to acquired properties providing cost efficiencies and economies of scale.

Lease operating expenses increased by approximately $35.3 million, or 535%, to $41.9 million for the year ended December 31, 2007, from $6.6 million for the year ended December 31, 2006. Lease operating expenses increased primarily due to higher production and costs associated with the 2007 acquisitions in the Mid-Continent Deep and Mid-Continent Shallow regions.

Transportation Expenses

Transportation expenses increased to $5.6 million for the year ended December 31, 2007, from approximately $40,000 for the year ended December 31, 2006, primarily due to increased production from the 2007 acquisitions in the Mid-Continent Deep and Mid-Continent Shallow regions.

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General and Administrative Expenses

General and administrative expenses are costs not directly associated with field operations and include costs of employees and executive officers, related benefits, office leases and professional fees. As noted below, total general and administrative expenses increased; however, expenses per equivalent unit of production decreased to $1.61 per Mcfe for the year ended December 31, 2007, compared to $13.61 per Mcfe for the year ended December 31, 2006, due to increases in production, cost efficiencies and economies of scale provided by acquired properties.

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 $51.4 million for the year ended December 31, 2007, from $38.0 million for the year ended December 31, 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 during 2007, the Company hired approximately 150 employees (including approximately 100 corporate, administrative and support employees with the August 2007 acquisition in the Mid-Continent Deep region) and as a result, salaries and benefits expense increased approximately $13.5 million over 2006. Costs to perform the necessary functions associated with being a growing company were $13.8 million during 2007, compared to $5.6 million during 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. 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 during the year ended December 31, 2007. Unit-based compensation expense incurred during the year ended December 31, 2006 was higher compared to that incurred in 2007, primarily due to expense associated with unit awards granted in conjunction with the Company's IPO in January 2006.

Exploration Costs

The Company incurred exploration costs of approximately $4.1 million and $0.3 million during the years ended December 31, 2007 and 2006, respectively. The increase in expense during 2007 primarily represents payments for access to 3-D seismic and other data libraries in the Mid-Continent Deep region. Increased unproved leasehold and delay rental costs also contributed to the increase.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $64.7 million, to $69.1 million for the year ended December 31, 2007, from $4.4 million for the year ended December 31, 2006. Depreciation, depletion and amortization per Mcfe also increased, to $2.16 per Mcfe for the year ended December 31, 2007, from $1.56 per Mcfe for the year ended December 31, 2006. Higher total production levels, primarily due to the Company's acquisitions in the Mid-Continent Deep and Mid-Continent Shallow regions in 2007, were the main reason for the increase. Approximately $37.9 million of the increase was as a result of depletion related to the August 2007 acquisition in the Mid-Continent Deep region. The properties acquired earlier in 2007 in the Mid-Continent Shallow region contributed approximately $12.4 million to the increase.

Taxes, Other Than Income Taxes

Taxes, other than income taxes, which consists primarily of production and ad valorem taxes, increased by approximately $22.2 million to $22.4 million for the year ended December 31, 2007, from $0.2 million for the year ended December 31, 2006. Production taxes, which are a function of revenues generated from production, increased by approximately $14.8 million compared to the year ended December 31, 2006. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, increased by approximately $5.3 million compared to the year ended December 31, 2006.

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Other Income and (Expenses)

Other income and (expenses) increased by approximately $62.8 million, to expense of $70.9 million for the year ended December 31, 2007, compared to expense of $8.1 million for the year ended December 31, 2006, primarily due to an increase in interest expense of approximately $33.1 million related to higher debt levels associated with borrowings to fund acquisitions and drilling. In addition, total losses on interest rate swaps increased by approximately $28.4 million over the year ended December 31, 2006. The Company's interest rate swaps were not designated as cash flow hedges under SFAS 133, even though they reduce exposure to changes in interest rates (see Note 9). The changes in fair values of these instruments were recorded as an unrealized loss of approximately $29.5 million and an unrealized gain of approximately $0.1 million for the years ended December 31, 2007 and 2006, respectively. These amounts are non-cash items.

Income Tax Benefit (Expense)

Income tax was an expense of approximately $4.8 million for the year ended December 31, 2007 and a benefit of approximately $2.0 million for the year ended December 31, 2006. The Company is treated as a partnership for federal and state income tax purposes; however, certain of the Company's subsidiaries are Subchapter C-corporations subject to corporate income taxes. Tax expense for the year ended December 31, 2007 relates primarily to 2006 expense recovery. The Company's taxable subsidiaries generated net operating losses for the year ended December 31, 2006. During the year ended December 31, 2007, expenses were recovered by Linn Operating, Inc. through an intercompany charge for services to Linn Energy, which resulted in income tax expense for Linn Energy for the year ended December 31, 2007.

Results of Operations – Discontinued Operations

The following table presents comparative data for the Company's discontinued operations related to its Appalachian Basin assets. See Note 2 for additional details about discontinued operations.

	Year Ended December 31,		
	2008	2007	2006
Average daily production:			
Total (MMcfe/d)	12	24	22

The sale of properties in the Appalachian Basin (see Note 2) will produce taxable gains or losses to unitholders. The amount of gain or loss will be determined at unitholder level, based on each affected unitholder's tax basis in the disposed properties and allocated sale proceeds and in accordance with the terms of the Company's Second Amended and Restated Limited Liability Company Agreement, as amended, and the applicable tax laws, and will be reflected in unitholder K-1s to be provided in the spring of 2009.

Liquidity and Capital Resources

The Company has utilized public and private equity, proceeds from bank borrowings and issuance of senior notes, 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. The Company manages its working capital and cash requirements to borrow only as needed. The Company had $415.4 million in available borrowing capacity at January 30, 2009.

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, if available, or obtain additional debt or equity financing. The Company's credit facility and senior notes impose 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.

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Cash Flows

The following presents a comparative cash flow summary:

	Year Ended December 31, 2008	2007	Variance
		(in thousands)	
Net cash:			
Provided by (used in) operating activities (1) (2)	$ 179,515	$ (44,814)	$ 224,329
Used in investing activities	(35,550)	(2,892,420)	2,856,870
Provided by (used in) financing activities	(116,738)	2,932,080	(3,048,818)
Increase (decrease) in cash and cash equivalents	$ 27,227	$ (5,154)	$ 32,381

(1) The years ended December 31, 2008 and 2007 include premiums paid for derivatives of approximately $129.5 million and $279.3 million, respectively. Premiums paid during the year ended December 31, 2008 include $67.6 million for contracts that replaced those with Lehman Commodity Services (see Note 13).

(2) During the year ended December 31, 2008, the Company cancelled (before the contract settlement date) derivative contracts on estimated future gas production resulting in realized losses of $81.4 million. The future gas production under the canceled contracts primarily related to properties in the Appalachian Basin and Verden areas (see Note 2).

Operating Activities
At December 31, 2008, the Company had $28.7 million cash and cash equivalents compared to $1.4 million at December 31, 2007. Cash provided by operating activities for the year ended December 31, 2008 was approximately $179.5 million, compared to cash used by operating activities of $44.8 million for the year ended December 31, 2007. The increase in cash provided by operating activities was primarily due to increased production during the year ended December 31, 2008. During the year ended December 31, 2008, the Company canceled (before the contract settlement date) derivative contracts on estimated future gas production primarily associated with properties in the Appalachian Basin and Verden areas (see Note 2) resulting in realized losses of approximately $81.4 million. In addition, premiums paid for derivatives were approximately $129.5 million during the year ended December 31, 2008, compared to $279.3 million during the year ended December 31, 2007. Premiums paid during the year ended December 31, 2008 include $67.6 million for contracts that replaced those with Lehman Commodity Services (see Note 13). The premiums paid were for derivative contracts that hedge future production for up to five years. These derivative contracts are expected to provide or stabilize the Company's future cash flow and were funded through the Company's credit facility. See Note 9 for additional details about commodity derivatives. The amount of derivative contracts the Company enters into in the future will be directly related to expected future production.

Investing Activities
Cash used in investing activities was approximately $35.6 million for the year ended December 31, 2008, compared to $2.89 billion for the year ended December 31, 2007. The decrease in cash used in investing activities was due to a decrease in acquisition and development activity and an increase in proceeds from asset sales during the year ended December 31, 2008, compared to the year ended December 31, 2007.

The total cash used in investing activities for the year ended December 31, 2008 includes $510.6 million for the January 2008 acquisition of properties in the Mid-Continent Shallow region (see Note 3). Other acquisitions, including acquisitions of additional working interests in current wells, were approximately $82.8 million and other property and equipment purchases were $9.1 million. The total for the year ended December 31, 2008 also includes approximately $330.6 million for the drilling and development of oil and gas properties. During the year ended December 31, 2008, the Company also received proceeds from the sales of oil and gas properties to XTO, Laredo and Devon, and other plant and equipment totaling approximately $897.6 million (see Note 2).

For 2009, the Company estimates its total drilling and development capital expenditures will be approximately $150.0 million compared to approximately $321.3 million from continuing operations in 2008. This estimate is under continuous review and is subject to on-going adjustment. The Company expects to fund these capital expenditures with cash flow from operations.

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Financing Activities

Cash used by financing activities was approximately $116.7 million for the year ended December 31, 2008, compared to cash provided by financing activities of $2.93 billion for the year ended December 31, 2007. During the year ended December 31, 2008, total proceeds from the issuance of debt were $1.46 billion and total repayments of debt were $1.25 billion. See additional discussion about the Company's credit facility, term loan and senior notes below. In addition, see detail of distributions paid during the year ended December 31, 2008 below.

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. The following provides a summary of distributions paid by the Company during the year ended December 31, 2008:

Date Paid	Period Covered by Distribution	Distribution Per Unit		Total Distribution (in millions)	
November 2008	July 1 – September 30, 2008	$	0.63	$	72.6
August 2008	April 1 – June 30, 2008	$	0.63		72.6
May 2008	January 1 – March 31, 2008	$	0.63		72.6
February 2008	October 1 – December 31, 2007	$	0.63		72.2
				$	290.0

In January 2009, the Company's Board of Directors declared a cash distribution of $0.63 per unit with respect to the fourth quarter of 2008. The distribution totaled approximately $72.5 million and was paid on February 13, 2009 to unitholders of record as of the close of business on February 6, 2009.

Credit Facility

The Company currently has a $1.85 billion borrowing base under its Third Amended and Restated Credit Agreement ("Credit Facility") with a maturity of August 2010. 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. Significant declines in oil, gas or NGL prices may result in a decrease in the borrowing base. During 2009, the Company plans to renegotiate its Credit Facility, which is anticipated to result in increased interest expense. There can be no assurance that the borrowing base under a new Credit Facility will remain at the current level.

At the Company's election, interest on borrowings under the Credit Facility is determined by reference to either the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.00% and 1.75% per annum or the alternate base rate ("ABR") plus an applicable margin between 0% and 0.25% per annum. The Company is required to pay a fee ranging from 0.3% to 0.375% per year on the unused portion of the Credit Facility.

As noted above, the Company depends on its Credit Facility for future capital needs. In addition, the Company has drawn on the Credit Facility to fund or partially fund quarterly cash distribution payments, since it uses operating cash flows for investing activities and borrows as cash is needed. Absent such borrowing, the Company would have at times experienced a shortfall in cash available to pay the declared quarterly cash distribution amount. If an event of default occurs and is continuing under the Credit Facility, the Company would be unable to make borrowings to fund distributions. For additional information about this and other risk factors that could affect the Company, see “Credit and Capital Market Disruptions” in the “Executive Overview” above and also Part I. Item 1A. “Risk Factors.”

Certain subsidiaries of Lehman Holdings, including Lehman Commodity Services, were lenders in the Company’s Credit Facility. In September 2008 and October 2008, Lehman Holdings and Lehman Commodity Services, respectively, filed voluntary petitions for reorganization under Chapter 11 (see “Contingencies” below). In October

2008, the Company replaced Lehman Holdings' subsidiaries with another lender and Lehman Holdings' subsidiaries no longer participate in the Company's Credit Facility. At January 30, 2009, available borrowing under the Credit Facility was $415.4 million, which includes a $6.2 million reduction in availability for outstanding letters of credit.

Term Loan

On January 31, 2008, in order to fund a portion of the January 2008 acquisition of oil and gas properties in the Mid-Continent Shallow region (see Note 3), the Company entered into a $400.0 million Second Lien Term Loan Agreement ("Term Loan") maturing on July 31, 2009. Interest was determined by reference to LIBOR plus an applicable margin of 5.0% for the first twelve months and 7.5% for the remaining period until maturity, or a domestic bank rate plus an applicable margin of 3.5% for the first twelve months and 6.0% for the remaining period until maturity. On June 30, 2008, the Company repaid $243.6 million in indebtedness under the Term Loan with net proceeds from the Senior Notes (see below). On July 1, 2008, the Company repaid the balance of the Term Loan of $156.4 million. Deferred financing fees associated with the Term Loan of approximately $4.6 million were written off during the year ended December 31, 2008.

Senior Notes

On June 24, 2008, the Company entered into a purchase agreement with a group of initial purchasers ("Initial Purchasers") pursuant to which the Company agreed to issue $255.9 million in aggregate principal amount of the Company's senior notes due 2018 ("Senior Notes"). The Senior Notes were offered and sold to the Initial Purchasers and then resold to qualified institutional buyers each in transactions exempt from the registration requirements under the Securities Act of 1933, as amended ("Securities Act"). The Company used the net proceeds (after deducting the Initial Purchasers' discounts and offering expense) of approximately $243.6 million to repay loans outstanding under the Company's Term Loan (see above). In connection with the Senior Notes, the Company incurred financing fees of approximately $7.8 million, which will be amortized over the life of the Senior Notes; the expense is recorded in "interest expense, net of amounts capitalized" on the consolidated statement of operations. The $5.9 million discount on the Senior Notes will be amortized over the life of the Senior Notes; the expense is recorded in "interest expense, net of amounts capitalized" on the consolidated statement of operations. As of January 30, 2009, the net carrying value of the Senior Notes was approximately $250.2 million and the fair value was approximately $201.5 million. The fair value of the Senior Notes was estimated based on prices quoted from third-party financial institutions.

The Senior Notes were issued under an Indenture dated June 27, 2008, mature on July 1, 2018 and bear interest at 9.875%. Interest is payable semi-annually beginning January 1, 2009. The Senior Notes are general unsecured senior obligations of the Company and are effectively junior in right of payment to any secured indebtedness of the Company to the extent of the collateral securing such indebtedness. Each of the Company's material subsidiaries guaranteed the Senior Notes on a senior unsecured basis. The Indenture provides that the Company may redeem: (i) on or prior to July 1, 2011, up to 35% of the aggregate principal amount of the Senior Notes at a redemption price of 109.875% of the principal amount, plus accrued and unpaid interest; (ii) prior to July 1, 2013, all or part of the Senior Notes at a redemption price equal to the principal amount, plus a make whole premium (as defined in the Indenture) and accrued and unpaid interest; and (iii) on or after July 1, 2013, all or part of the Senior Notes at redemption prices equal to 104.938% in 2013, 103.292% in 2014, 101.646% in 2015 and 100% in 2016 and thereafter. The Indenture also provides that, if a change of control (as defined in the Indenture) occurs, the holders have a right to require the Company to repurchase all or part of the Senior Notes at a redemption price equal to 101%, plus accrued and unpaid interest.

The Senior Notes' Indenture contains covenants that, among other things, limit the Company's ability to: (i) pay distributions on, purchase or redeem the Company's units or redeem its subordinated debt; (ii) make investments; (iii) incur or guarantee additional indebtedness or issue certain types of equity securities; (iv) create certain liens;

(v) sell assets; (vi) consolidate, merge or transfer all or substantially all of the Company's assets; (vii) enter into agreements that restrict distributions or other payments from the Company's restricted subsidiaries to the Company; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries.

In connection with the issuance and sale of the Senior Notes, the Company entered into a Registration Rights Agreement with the Initial Purchasers. Under the Registration Rights Agreement, the Company agreed to use its

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reasonable best efforts to file with the SEC and cause to become effective a registration statement relating to an offer to issue new notes having terms substantially identical to the Senior Notes in exchange for outstanding Senior Notes. In certain circumstances, the Company may be required to file a shelf registration statement to cover resales of the Senior Notes. The Company will not be obligated to file the registration statements described above if the restrictive legend on the Senior Notes has been removed and the Senior Notes are freely tradable (in each case, other than with respect to persons that are affiliates of the Company) pursuant to Rule 144 under the Securities Act, as of the 366th day after the Senior Notes were issued. If the Company fails to satisfy its obligations under the Registration Rights Agreement, the Company may be required to pay additional interest to holders of the Senior Notes under certain circumstances.

Fair Value of Financial Instruments

The Company accounts for its oil and gas commodity derivatives and interest rate swaps at fair value on a recurring basis (see Note 10). Effective January 1, 2008, the Company adopted SFAS No. 157, “Fair Value Measurements” (“SFAS 157”) for these financial instruments. SFAS 157 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value, and enhances disclosure requirements for fair value measurements. The impact of the adoption of SFAS 157 to the Company’s results of operations was a decrease in net income of approximately $4.0 million, or $0.04 per unit, for the year ended December 31, 2008, resulting from assumed credit risk adjustments. The credit risk adjustments are based on published credit ratings, public bond yield spreads and credit default swap spreads. The impact of the Company’s assumed credit risk adjustment was a gain of approximately $8.9 million. The impact of the counterparties’ assumed credit risk adjustment was a loss of approximately $12.9 million.

The Company’s counterparties are participants in its Credit Facility (see Note 8) which is secured by the Company’s oil and gas reserves; therefore, the Company is not required to post any collateral. The Company does not require collateral from the counterparties. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that are also lenders in the Company’s Credit Facility, each of which currently meet the Company’s minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company’s counterparties on an ongoing basis. In accordance with the Company’s standard practice, its commodity and interest rate swap derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss due to counterparty nonperformance is somewhat mitigated at December 31, 2008.

Off-Balance Sheet Arrangements

At December 31, 2008, the Company did not have any off-balance sheet arrangements.

Contingencies

In September and October 2008, Lehman Holdings and Lehman Commodity Services, respectively, filed voluntary petitions for reorganization under Chapter 11 (see Note 13). As of December 31, 2008, the Company had a receivable of approximately $67.6 million from Lehman Commodity Services for canceled derivative contracts. The Company is pursuing various legal remedies to protect its interests. Based on market expectations, at December 31, 2008, the Company estimated approximately $6.7 million of the receivable balance to be collectible. The net receivable of approximately $6.7 million is included in “other current assets, net” on the consolidated balance sheet at December 31, 2008. The related expense is included in "gain (loss) on oil and gas derivatives" on the consolidated statement of operations for the year ended December 31, 2008. The Company believes that the ultimate disposition of this matter will not have a material adverse effect on its business, financial position, results of operations or liquidity.

During the years ended December 31, 2008, 2007 and 2006, the Company made no significant payments to settle any legal, environmental or tax proceedings. 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.

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Commitments and Contractual Obligations

The following summarizes, as of December 31, 2008, certain long-term contractual obligations that are reflected in the consolidated balance sheet and/or disclosed in the accompanying notes thereto:

Contractual Obligations	Payments Due Total	2009	2010 – 2011 (in thousands)	2012 – 2013	2014 and Beyond
Long-term debt obligations:					
Credit facility	$ 1,403,393	$	$ 1,403,393	$	$
Senior notes	255,927				255,927
Interest (1)	294,977	59,937	70,766	50,546	113,728
Operating lease obligations:					
Office, property and equipment leases	20,608	3,538	7,059	6,011	4,000
Other noncurrent liabilities:					
Asset retirement obligations	28,922		112	208	28,602
Other:					
Interest rate swaps	82,422	43,969	38,453		
Commodity derivatives	3,933		615	3,318	
Services agreement	547	212	335		
Executive severance	692	507	185		
	$ 2,091,421	$ 108,163	$ 1,520,918	$ 60,083	$ 402,257

(1) Represents interest on the Company's Credit Facility computed at the weighted average LIBOR rate of 2.47% through maturity in August 2010 and interest on Senior Notes computed at a fixed rate of 9.875% through maturity in July 2018.

Capital Structure

The Company's capitalization is presented below:

	December 31, 2008	2007
	(in thousands)	
Cash and cash equivalents	$ 28,668	$ 1,441
Credit facility	$ 1,403,393	$ 1,443,000
Senior notes, net	250,175	
Other noncurrent debt		830
	1,653,568	1,443,830
Total unitholders' capital	2,760,686	2,026,641

Total capitalization	$ 4,414,254	$ 3,470,471

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Critical Accounting Policies and Estimates

The discussion and analysis of the Company’s financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles (“GAAP”). The preparation of the consolidated financial statements in conformity with GAAP requires management of the Company to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses. The estimates that are particularly significant to the financial statements include estimates of the Company’s reserves of oil, gas and NGL, 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. These estimates and assumptions are based on management’s best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. Illiquid credit markets and volatile equity and energy markets have combined to increase the uncertainty inherent in such estimates and assumptions. As future events and their effects cannot be determined with precision, actual results could differ from these estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

Below, the Company has provided expanded discussion of its more significant accounting policies, estimates and judgments, i.e., those that reflect more significant estimates and assumptions used in the preparation of financial statements. See Note 1 for a discussion of additional accounting policies and estimates made by Company management.

Oil and Gas Reserves

The Company’s estimates of proved reserves are based on the quantities of oil, gas and NGL that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. The independent engineering firm DeGolyer and MacNaughton prepared a reserve and economic evaluation of all of the Company properties on a well-by-well basis as of December 31, 2008.

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

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

Oil and Gas Properties/Property and Equipment

Proved Oil and Gas Properties
The Company accounts for oil and gas properties under the successful efforts method. Under this method, all leasehold and development costs of proved properties are capitalized and amortized on a unit-of-production basis over

the remaining life of the proved reserves and proved developed reserves, respectively.

The Company evaluates the impairment of its proved oil and gas properties on a field-by-field basis whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. The carrying amount of proved oil and gas properties are reduced to fair value when the expected undiscounted future cash flows are less than the asset's net book value. Cash flows are determined based upon reserves using prices, costs and discount factors consistent with those used for internal decision making. The underlying commodity prices

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embedded in the Company's estimated cash flows are the product of a process that begins with the Henry Hub forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Although prices used are likely to approximate market, they do not necessarily represent current market prices. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs for oil and gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. The Company capitalizes interest on borrowed funds related to its share of costs associated with the drilling and completion of new oil and gas wells. Interest is capitalized only during the periods in which these assets are brought to their intended use. The Company capitalized interest costs from continuing operations of $0.9 million, $0.5 million and $0.1 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Unproved Oil and Gas Properties

Unproved properties consist of costs incurred to acquire unproved leasehold as well as costs incurred to acquire unproved resources. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term has expired. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The carrying value of the Company's unproved resources, which were acquired in connection with business acquisitions, was determined using the market-based weighted average cost of capital rate, subjected to additional project-specific risking factors. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. As the unproved resources are developed and proven, the associated costs are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved resources for impairment annually on the basis of the experience of the Company in similar situations and other information about such factors as the primary lease terms of those properties, the average holding period of unproved properties and the relative proportion of such properties on which proved reserves have been found in the past.

Impairment

Based on the analysis described above, the Company recorded non-cash impairment of oil and gas properties of approximately $30.2 million before and after tax for the year ended December 31, 2008, which is included in "impairment of goodwill and long-lived assets" on the consolidated statement of operations. The Company recorded no impairment of oil and gas properties in continuing operations for the years ended December 31, 2007 or 2006.

Exploration Costs

Geological and geophysical costs, delay rentals, amortization of unproved leasehold costs and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration costs. The costs of any exploratory wells are carried as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Company is making sufficient progress towards assessing the reserves and the economic and operating viability of the project.

Other Property and Equipment

Other property and equipment includes gas gathering systems, pipelines, buildings, software, data processing and telecommunications equipment, office furniture and equipment, and other fixed assets. These items are recorded at cost and are depreciated using the straight-line method based on expected lives ranging from 3 to 39 years for the individual asset or group of assets.

Goodwill

Goodwill represents the excess of the cost of an acquired business over the net amounts assigned to assets acquired and liabilities assumed. The Company recorded goodwill in conjunction with its August 2007 acquisition in the Mid-Continent Deep region, all of which was allocated to the Mid-Continent Deep reporting unit. At December 31, 2007, the Company had $64.4 million of goodwill recorded. During the year ended December 31, 2008, the Company recorded adjustments to goodwill related to the sales of Verden and Woodford Shale assets and post closing adjustments. See Note 4 for additional details.

Goodwill is not amortized to earnings but is tested annually during the fourth quarter or whenever events or changes in circumstances indicate that the carrying value may not be recoverable. Goodwill is subject to annual reviews for impairment based on a two-step accounting test. The first step is to compare the estimated fair value of reporting units that have recorded goodwill with the recorded net book value (including the goodwill) of the reporting unit. If the estimated fair value of the reporting unit is higher than the recorded net book value, no impairment is deemed to exist and no further testing is required. If, however, the estimated fair value of the reporting unit is below the recorded net book value, then a second step must be performed to determine the goodwill impairment required, if any. The second step utilizes the estimated fair value from the first step as the purchase price in a hypothetical acquisition of the reporting unit.

The Company performed its annual goodwill impairment review in the fourth quarter of 2008. During the fourth quarter of 2008, there were disruptions in credit markets and reductions in global economic activity which had adverse impacts on stock markets and oil and gas commodity prices, both of which contributed to a decline in the Company’s unit price and corresponding market capitalization. For most of the fourth quarter, the Company’s market capitalization value was below the recorded net book value of its balance sheet, including goodwill. Because quoted market prices for the Company’s reporting units are not available, management used judgment in determining the estimated fair value of its reporting units for purposes of performing the annual goodwill impairment test. All available information was used to make these fair value determinations, including the present values of expected future cash flows using prices, costs and discount factors consistent with those used for internal decision making. The accounting principles regarding goodwill acknowledge that the observed market prices of individual trades of a company’s stock (and thus its computed market capitalization) may not be representative of the fair value of the company as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity’s individual common stock. In most industries, including the Company’s, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest; therefore, a control premium was added to the Company’s fair value calculations. This control premium was judgmental and based on observations of acquisitions in the industry.

Based on its analysis, the Company concluded that impairment of the entire amount of recorded goodwill for the Mid-Continent Deep reporting unit was required as of December 31, 2008. A $20.3 million before and after tax non-cash impairment of goodwill was recorded during the year ended December 31, 2008, which is included in “impairment of goodwill and long-lived assets” on the consolidated statement of operations. This impairment is not expected to result in current or future cash expenditures.

Revenue Recognition

Sales of oil, gas and NGL are recognized when oil, gas or NGL has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured, and the sales price is fixed or determinable. Virtually all of the Company’s contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, gas and NGL, and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

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The Company has elected the entitlements method to account for gas production imbalances. Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Under the entitlements method, any amount received in excess of the Company's share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. At December 31, 2008 and 2007, the Company had gas production imbalance receivables of approximately $17.1 million and $17.7 million, respectively, which are included in "accounts receivable – trade, net" on the consolidated balance sheet and gas production imbalance payables of approximately $9.9 million and $11.5 million, respectively, which are included in "accounts payable and accrued expenses" on the consolidated balance sheets.

The Company engages in the purchase, gathering and transportation of third-party gas and subsequently markets such gas to independent purchasers under separate arrangements. As such, the Company separately reports third-party marketing sales and gas marketing expenses. Marketing margins related to the Company's production are included in oil, gas and NGL sales.

The Company generates electricity with excess gas, which it uses to serve certain of its operating facilities in Brea, California. Any excess electricity is sold to the California wholesale power market. This revenue is included in "other revenues" on the consolidated statement of operations.

Asset Retirement Obligations

The Company has the obligation to plug and abandon oil and gas wells and related equipment at the end of production operations. Estimated asset retirement costs are recognized when the obligation is incurred, and are amortized over proved developed reserves using the units of production method. Accretion expense is included in "depreciation, depletion and amortization" on the consolidated statement of operations. Asset retirement costs are estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates. Revisions in estimated liabilities can result from revisions of estimated inflation rates, escalating retirement costs and changes in the estimated timing of settling asset retirement obligations (see Note 12).

Derivative Instruments

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. These transactions are in the form of swap contracts, collars and put options. A put option requires the Company to pay the counterparty a premium equal to the fair value of the option at the purchase date and receive from the counterparty the excess, if any, of the fixed floor over the floating market price. Additionally, the Company uses derivative financial instruments in the form of interest rate swaps to mitigate its interest rate exposure.

The Company accounts for these activities pursuant to 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 sheet as assets or liabilities. The Company accounts for its derivatives at fair value as an asset or liability and the change in the fair value of the derivatives is included in earnings since none of the Company's commodity or interest rate derivatives are designated as hedges under SFAS 133. The Company determines the fair value of its derivative financial instruments in accordance with SFAS 157, which defines fair value and establishes a framework for measuring fair value. The Company utilizes pricing models for significantly similar instruments to determine fair value. The models use a variety of techniques to arrive at fair value, including quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward curves generated from a compilation of data gathered from third parties. See Note 9 and Note 10 for additional details about the Company's derivative financial instruments. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for discussion regarding the Company's sensitivity analysis for the Company's financial instruments.

Purchase Accounting

The establishment of the asset base through the date of this report has included numerous acquisitions of working interests in oil and gas properties. These acquisitions have been accounted for using the purchase method of accounting as prescribed in SFAS No. 141, "Business Combinations." See Note 3 for additional details about acquisitions.

In connection with a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. The purchase price allocations are based on independent appraisals, discounted cash flows, quoted market prices and estimates by management. In addition, when appropriate, the Company reviews comparable purchases and sales of oil and gas properties within the same regions, and uses that data as a proxy for fair market value; i.e., the amount a willing buyer and seller would enter into in exchange for such properties. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

The Company made various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions related to the estimated fair values assigned to proved and unproved oil and gas properties. To estimate the fair values of these properties, the Company prepared estimates of oil and gas reserves. 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. For estimated proved reserves, the future net revenues were discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate was subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved properties, the discounted future net revenues of probable and possible reserves were reduced by additional risk-weighting factors.

Deferred taxes must be recorded for any differences between the assigned values and the tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

While the estimates of fair value for the assets acquired and liabilities assumed have no effect on cash flows, they can have an effect on the future results of operations. Generally, higher fair values assigned to oil and gas properties result in higher future depreciation, depletion and amortization expense, which results in decreased future net earnings. Also, a higher fair value assigned to oil and gas properties, based on higher future estimates of oil and gas prices, could increase the likelihood of impairment in the event of lower commodity prices or higher operating costs than those originally used to determine fair value. The recording of an impairment has no effect on cash flows but results in a decrease in net income for the period in which the impairment is recorded.

Unit-Based Compensation

The Company accounts for unit-based compensation pursuant to SFAS No. 123 (revised 2004), "Share-Based Payment" ("SFAS 123R"). SFAS 123R requires an entity to recognize the grant-date fair-value of stock options and other equity-based compensation issued to employees in the income statement and eliminates the alternative to use the intrinsic value method of accounting that was provided under the original provisions of SFAS 123, which resulted in no compensation expense recorded in the financial statements related to the issuance of equity awards to employees. It establishes fair value as the measurement objective in accounting for share-based payment arrangements and requires companies to apply a fair-value-based measurement method in accounting for share-based payment transactions with employees. The Company also follows the guidance in Staff Accounting Bulletin ("SAB") No. 107, "Share-Based Payment," which contains the express views of the SEC staff regarding the interaction between SFAS 123R and certain SEC rules and regulations and provides the staff's views regarding the valuation of share-based payment arrangements for public companies. See Note 7 for additional details about the Company's accounting for unit-based compensation.

New Accounting Pronouncements

See Note 19 for details regarding SFAS 157 implementation effective January 1, 2008 and January 1, 2009, and also for details regarding SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement 133” (“SFAS 161”) implementation effective January 1, 2008.

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Item 7A. 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.

A reference to a “Note” herein refers to the accompanying Notes to Consolidated Financial Statements contained in Item 8. “Financial Statements and Supplementary Data.”

Commodity Price Risk

The Company enters into derivative contracts with respect to a portion of its projected production through various transactions that provide an economic hedge of the risk related to the future prices received. The Company does not enter into derivative contracts for trading purposes. See Note 9 for additional details. At December 31, 2008, the fair value of contracts that settle during the next twelve months was an asset of approximately $346.1 million and a liability of zero for a net asset of approximately $346.1 million. A 10% increase in the index oil and gas prices above the December 31, 2008 prices for the next twelve months would result in a net asset of approximately $273.7 million which represents a decrease in the fair value of approximately $72.4 million; conversely, a 10% decrease in the index oil and gas prices would result in a net asset of approximately $419.2 million which represents an increase in the fair value of approximately $73.1 million.

Interest Rate Risk

At December 31, 2008, the Company had long-term debt outstanding under its Credit Facility of approximately $1.40 billion, which incurred interest at floating rates. See Note 8 for additional details. At December 31, 2008, the interest rate based on LIBOR was approximately 2.47%. A 1% increase in LIBOR would result in an estimated $14.0 million increase in annual interest expense. The Company has entered into interest rate swap agreements based on LIBOR to minimize the effect of fluctuations in interest rates. See Note 9 for additional details.

Credit Risk

The Company accounts for its oil and gas commodity derivatives and interest rate swaps at fair value on a recurring basis in accordance with the provisions of SFAS 157 (see Note 10). The fair value of these derivative financial instruments includes the impact of assumed credit risk adjustments, which are based on the Company’s and counterparties’ published credit ratings, public bond yield spreads and credit default swap spreads, as applicable.

At December 31, 2008, the average public bond yield spread utilized to estimate the impact of the Company’s credit risk on derivative liabilities was approximately 9.9%. A 1% increase in the average public bond yield spread would result in an estimated $1.9 million increase in net income for the year ended December 31, 2008. At December 31, 2008, the credit default swap spreads utilized to estimate the impact of counterparties’ credit risk on derivative assets ranged between 0% and 2.6%. A 1% increase in each of the counterparties’ credit default swap spreads would result in an estimated $13.1 million decrease in net income for the year ended December 31, 2008.

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Item 8. Financial Statements and Supplementary Data

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MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed under the supervision of our Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or processes may deteriorate.

As of December 31, 2008, our management assessed the effectiveness of the Company’s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2008, based on those criteria. KPMG LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company’s internal control over financial reporting as of December 31, 2008, which is included herein.

/s/ Linn Energy, LLC

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
Linn Energy, LLC:

We have audited the accompanying consolidated balance sheets of Linn Energy, LLC and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, unitholders' capital (deficit), and cash flows for each of the years in the three-year period ended December 31, 2008. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Linn Energy, LLC and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Linn Energy, LLC's internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 25, 2009, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 25, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
Linn Energy, LLC:

We have audited Linn Energy, LLC's internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Linn Energy, LLC's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Linn Energy, LLC maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Linn Energy, LLC and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, unitholders' capital (deficit) and cash flows for each of the years in the three-year period ended December 31, 2008, and our report dated February 25, 2009, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 25, 2009

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LINN ENERGY, LLC
CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(in thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 28,668	$ 1,441
Accounts receivable – trade, net	144,882	149,850
Derivative instruments	368,951	26,100
Other current assets, net	21,430	5,768
Total current assets	563,931	183,159
Noncurrent assets:		
Oil and gas properties (successful efforts method)	3,831,183	3,506,559
Less accumulated depletion and amortization	(278,805)	(120,498)
	3,552,378	3,386,061
Other property and equipment	111,459	149,589
Less accumulated depreciation	(13,171)	(12,150)
	98,288	137,439
Derivative instruments	493,705	
Goodwill		64,419
Other noncurrent assets, net	13,718	36,625
	507,423	101,044
Total assets	$ 4,722,020	$ 3,807,703
Liabilities and Unitholders' Capital		
Current liabilities:		
Accounts payable and accrued expenses	$ 163,662	$ 222,149
Derivative instruments	47,005	6,148
Other accrued liabilities	27,163	14,430
Total current liabilities	237,830	242,727
Noncurrent liabilities:		
Credit facility	1,403,393	1,443,000
Senior notes, net	250,175	
Derivative instruments	39,350	63,813
Other noncurrent liabilities	30,586	31,522
Total noncurrent liabilities	1,723,504	1,538,335
Unitholders' capital:		
114,079,533 and 113,815,914 units issued and outstanding at December 31, 2008 and 2007, respectively	2,109,089	2,374,660
Accumulated income (deficit)	651,597	(348,019)
	2,760,686	2,026,641
Total liabilities and unitholders' capital	$ 4,722,020	$ 3,807,703

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

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LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2008	2007	2006
	(in thousands, except per unit amounts)		
Revenues and other:			
Oil, gas and natural gas liquid sales	$ 755,644	$ 255,927	$ 21,372
Gain (loss) on oil and gas derivatives	662,782	(345,537)	103,308
Gas marketing revenues	12,846	11,589	
Other revenues	3,759	2,738	846
	1,435,031	(75,283)	125,526
Expenses:			
Lease operating expenses	115,402	41,946	6,603
Transportation expenses	17,597	5,575	40
Gas marketing expenses	11,070	9,100	
General and administrative expenses	77,391	51,374	37,997
Exploration costs	7,603	4,053	286
Bad debt expenses	1,436		12
Depreciation, depletion and amortization	194,093	69,081	4,352
Impairment of goodwill and long-lived assets	50,505		
Taxes, other than income taxes	61,435	22,350	243
(Gain) loss on sale of assets, net	(98,763)	1,767	28
	437,769	205,246	49,561
Other income and (expenses):			
Interest expense, net of amounts capitalized	(94,517)	(38,974)	(5,909)
Gain (loss) on interest rate swaps	(66,674)	(28,081)	363
Other, net	(7,702)	(3,822)	(2,581)
	(168,893)	(70,877)	(8,127)
Income (loss) from continuing operations before income taxes	828,369	(351,406)	67,838
Income tax benefit (expense)	(2,712)	(4,788)	1,973
Income (loss) from continuing operations	825,657	(356,194)	69,811
Discontinued operations:			
Gain (loss) on sale of assets, net of taxes	159,045	936	(45)
Income (loss) from discontinued operations, net of taxes	14,914	(9,091)	9,419
	173,959	(8,155)	9,374
Net income (loss)	$ 999,616	$ (364,349)	$ 79,185
Income (loss) per unit – continuing operations:			
Units – basic	$ 7.23	$ (5.17)	$ 2.33
Units – diluted	$ 7.23	$ (5.17)	$ 2.30
Income (loss) per unit – discontinued operations:			
Units – basic	$ 1.53	$ (0.12)	$ 0.31
Units – diluted	$ 1.52	$ (0.12)	$ 0.31
Net income (loss) per unit:			
Units – basic	$ 8.76	$ (5.29)	$ 2.64
Units – diluted	$ 8.75	$ (5.29)	$ 2.61
Weighted average units outstanding:			
Units – basic	114,140	68,916	28,281

Units – diluted		114,256		68,916		30,385
Class B – basic						1,737
Class B – diluted						1,737
Distributions declared per unit	$	2.52	$	2.18	$	1.15

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

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LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF UNITHOLDERS' CAPITAL (DEFICIT)

	Units	Unitholders' Capital	Accumulated Income (Deficit) (in thousands)	Treasury Units (at Cost)	Total Unitholders' Capital (Deficit)
December 31, 2005	20,518	$ 16,024	$ (62,855)	$	$ (46,831)
Sale of initial public offering units, net of underwriting discounts of $18,302 and expense of $4,339	12,450	225,139		13,671	238,810
Sale of private placement units, net of expense of $348	14,721	304,652			304,652
Issuance of units	613				
Cancellation of units	(5,499)	(100,778)		100,778	
Purchase of units				(114,449)	(114,449)
Distributions to unitholders		(32,056)			(32,056)
Unit-based compensation expenses		21,643			21,643
Net income			79,185		79,185
December 31, 2006	42,803	434,624	16,330		450,954
Sale of private placement units, net of expense of $34,334	69,874	2,085,666			2,085,666
Issuance of units	1,366	2,811			2,811
Cancellation of units	(227)	(7,399)		7,399	
Purchase of units				(7,399)	(7,399)
Distributions to unitholders		(154,963)			(154,963)
Unit-based compensation expenses		13,921			13,921
Net loss			(364,349)		(364,349)
December 31, 2007	113,816	2,374,660	(348,019)		2,026,641
Issuance of units	1,435	23,483			23,483
Cancellation of units	(1,171)	(14,998)		14,998	
Purchase of units				(14,998)	(14,998)
Distributions to unitholders		(289,915)			(289,915)
Reclassification of distributions paid on forfeited restricted units		182			182
Unit-based compensation expenses		15,677			15,677
Net income			999,616		999,616
December 31, 2008	114,080	$ 2,109,089	$ 651,597	$	$ 2,760,686

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

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LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2008	2007	2006
		(in thousands)	
Cash flow from operating activities:			
Net income (loss)	$ 999,616	$ (364,349)	$ 79,185
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	200,306	94,200	22,304
Impairment of goodwill and long-lived assets	50,505	3,343	1,000
Unit-based compensation and unit warrant expenses	15,677	13,921	21,643
Bad debt expenses	1,436		12
Amortization and write-off of deferred financing fees and other	17,024	5,746	5,658
(Gain) loss on sale of assets, net	(257,808)	831	73
Deferred income tax		3,360	(3,434)
Mark-to-market on derivatives:			
Total (gains) losses	(596,108)	373,618	(103,671)
Cash settlements	(20,901)	40,784	20,442
Cash settlements on canceled derivatives	(81,358)		
Premiums paid for derivatives	(129,520)	(279,313)	(49,807)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable – trade, net	3,673	(117,361)	(383)
(Increase) decrease in other assets	(2,556)	3,286	2,833
Increase (decrease) in accounts payable and accrued expenses	(36,451)	161,844	(6,782)
Increase in other liabilities	15,980	15,276	4,122
Net cash provided by (used in) operating activities	179,515	(44,814)	(6,805)
Cash flow from investing activities:			
Acquisition of oil and gas properties	(593,412)	(2,649,965)	(467,137)
Development of oil and gas properties	(330,615)	(185,534)	(46,963)
Deposit for oil and gas properties		(27,610)	(20,086)
Purchases of other property and equipment	(9,109)	(33,849)	(17,551)
Proceeds from sales of oil and gas properties and other property and equipment	897,586	4,538	106
Net cash used in investing activities	(35,550)	(2,892,420)	(551,631)
Cash flow from financing activities:			
Proceeds from sale and issuance of units		2,120,000	548,149
Purchase of units	(14,998)	(7,399)	(114,449)
Proceeds from issuance of debt	1,459,000	1,298,000	584,000
Principal payments on debt	(1,250,172)	(283,108)	(425,743)
Distributions to unitholders	(289,915)	(154,963)	(32,056)
Offering costs		(34,334)	(1,210)
Financing fees and other, net	(20,653)	(6,116)	(4,701)
Net cash provided by (used in) financing activities	(116,738)	2,932,080	553,990
Net increase (decrease) in cash and cash equivalents	27,227	(5,154)	(4,446)
Cash and cash equivalents:			
Beginning	1,441	6,595	11,041
Ending	$ 28,668	$ 1,441	$ 6,595

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

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Basis of Presentation and Significant Accounting Policies

(a) Nature of Business

Linn Energy, LLC ("Linn Energy" or the "Company") is an independent oil and gas company focused on the development and acquisition of long life properties which complement its asset profile in producing basins within the United States. Linn Energy began operations in March 2003 and was formed as a Delaware limited liability company in April 2005. The Company completed its initial public offering ("IPO") in January 2006 and its units representing limited liability company interests ("units") are listed on The NASDAQ Global Select Market under the symbol "LINE."

The operations of the Company are governed by the provisions of a limited liability company agreement executed by and among its members. The agreement includes specific provisions with respect to the maintenance of the capital accounts of each of the Company's unitholders. Pursuant to applicable provisions of the Delaware Limited Liability Company Act (the "Delaware Act") and the Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC (the "Agreement"), unitholders have no liability for the debts, obligations and liabilities of the Company, except as expressly required in the Agreement or the Delaware Act. The Company will remain in existence unless and until dissolved in accordance with the terms of the Agreement.

(b) Principles of Consolidation and Reporting

The Company presents its financial statements in accordance with U.S. generally accepted accounting principles ("GAAP"). The 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.

(c) Discontinued Operations

The Company's Appalachian Basin and Mid Atlantic Well Service, Inc. ("Mid Atlantic") operations have been classified as discontinued operations on the consolidated statement of operations for all periods presented. Unless otherwise indicated, information about the statement of operations that is presented in the notes to consolidated financial statements relates only to Linn Energy's continuing operations.

(d) Presentation Change

Certain amounts in the consolidated financial statements and notes thereto have been reclassified to conform to the 2008 financial statement presentation. In particular, the consolidated statement of operations includes categories of expense titled "lease operating expenses," "transportation expenses," "exploration costs," "bad debt expenses," "impairment of goodwill and long-lived assets," "taxes, other than income taxes" and "(gain) loss on sale of assets, net" which were not reported in prior period presentations. The new categories present expenses in greater detail than was previously reported and all comparative periods presented have been reclassified to conform to the 2008 financial statement presentation. There was no impact to net income (loss) for prior periods.

(e) Use of Estimates

The preparation of the accompanying consolidated financial statements in conformity with GAAP requires management of the Company to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses. The estimates that are particularly significant to the financial statements include estimates of the Company's reserves of oil, gas and natural gas liquids ("NGL"), 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. These estimates and assumptions are based on management's best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors,

including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. Illiquid credit markets and volatile equity and energy markets have combined to increase the uncertainty inherent in such estimates and assumptions. As future events and their effects cannot be determined with precision, actual results could differ from these estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

(f) Cash Equivalents

For purposes of the statement of cash flows, the Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents. The Company manages its working capital and cash requirements to borrow only as needed from its credit facility. At December 31, 2007, the Company had approximately $5.2 million of outstanding checks, the balance of which is included in "accounts payable and accrued expenses" on the consolidated balance sheet.

(g) Accounts Receivable – Trade, Net

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging, and existing industry and national economic data. The Company reviews its allowance for doubtful accounts monthly. Past due balances over 90 days and over a specified amount are reviewed individually for collectibility. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential recovery is remote. The balance in the Company's allowance for doubtful accounts related to trade accounts receivable was approximately $1.5 million and $100,000 at December 31, 2008 and 2007, respectively.

(h) Inventories

Materials, supplies and commodity inventories are valued at the lower of average cost or market.

(i) Oil and Gas Properties/Property and Equipment

Proved Oil and Gas Properties

The Company accounts for oil and gas properties under the successful efforts method. Under this method, all leasehold and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively.

The Company evaluates the impairment of its proved oil and gas properties on a field-by-field basis whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. The carrying amount of proved oil and gas properties are reduced to fair value when the expected undiscounted future cash flows are less than the asset's net book value. Cash flows are determined based upon reserves using prices, costs and discount factors consistent with those used for internal decision making. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with the Henry Hub forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs for oil and gas properties are capitalized at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. The Company capitalizes interest on borrowed funds related to its share of costs associated with the drilling and completion of new oil

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and gas wells. Interest is capitalized only during the periods in which these assets are brought to their intended use. The Company capitalized interest costs from continuing operations of $0.9 million, $0.5 million and $0.1 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Unproved Oil and Gas Properties

Unproved properties consist of costs incurred to acquire unproved leasehold as well as costs incurred to acquire unproved resources. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term has expired. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The carrying value of the Company's unproved resources, which were acquired in connection with business acquisitions, was determined using the market-based weighted average cost of capital rate, subjected to additional project-specific risking factors. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. As the unproved resources are developed and proven, the associated costs are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved resources for impairment annually on the basis of the experience of the Company in similar situations and other information about such factors as the primary lease terms of those properties, the average holding period of unproved properties and the relative proportion of such properties on which proved reserves have been found in the past.

Impairment

Based on the analysis described above, the Company recorded non-cash impairment of oil and gas properties of approximately $30.2 million before and after tax for the year ended December 31, 2008, which is included in "impairment of goodwill and long-lived assets" on the consolidated statement of operations. The Company recorded no impairment of oil and gas properties in continuing operations for the years ended December 31, 2007 or 2006.

Exploration Costs

Geological and geophysical costs, delay rentals, amortization of unproved leasehold costs and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration costs. The costs of any exploratory wells are carried as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Company is making sufficient progress towards assessing the reserves and the economic and operating viability of the project.

Other Property and Equipment

Other property and equipment includes gas gathering systems, pipelines, buildings, software, data processing and telecommunication equipment, office furniture and equipment, and other fixed assets. These items are recorded at cost and are depreciated using the straight-line method based on expected lives ranging from 3 to 39 years for the individual asset or group of assets.

(j) Goodwill

Goodwill represents the excess of the cost of an acquired business over the net amounts assigned to assets acquired and liabilities assumed. The Company accounts for goodwill in accordance with Statement of Financial Accounting Standards ("SFAS") No. 142, "Goodwill and Other Intangible Assets." The Company recorded goodwill in conjunction with its August 2007 acquisition in the Mid-Continent Deep region, all of which was allocated to the Mid-Continent Deep reporting unit. At December 31, 2007, the Company had $64.4 million of goodwill recorded. During the year ended December 31, 2008, the Company recorded adjustments to goodwill related to the sales of Verden and Woodford Shale assets and post closing adjustments. See Note 4 for additional details.

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Goodwill is not amortized to earnings but is tested annually during the fourth quarter or whenever events or changes in circumstances indicate that the carrying value may not be recoverable. Goodwill is subject to annual reviews for impairment based on a two-step accounting test. The first step is to compare the estimated fair value of reporting units that have recorded goodwill with the recorded net book value (including the goodwill) of the reporting unit. If the estimated fair value of the reporting unit is higher than the recorded net book value, no impairment is deemed to exist and no further testing is required. If, however, the estimated fair value of the reporting unit is below the recorded net book value, then a second step must be performed to determine the goodwill impairment required, if any. The second step utilizes the estimated fair value from the first step as the purchase price in a hypothetical acquisition of the reporting unit.

The Company performed its annual goodwill impairment review in the fourth quarter of 2008. During the fourth quarter of 2008, there were disruptions in credit markets and reductions in global economic activity which had adverse impacts on stock markets and oil and gas commodity prices, both of which contributed to a decline in the Company's unit price and corresponding market capitalization. For most of the fourth quarter, the Company's market capitalization value was below the recorded net book value of its balance sheet, including goodwill. Because quoted market prices for the Company's reporting units are not available, management used judgment in determining the estimated fair value of its reporting units for purposes of performing the annual goodwill impairment test. All available information was used to make these fair value determinations, including the present values of expected future cash flows using prices, costs and discount factors consistent with those used for internal decision making. The accounting principles regarding goodwill acknowledge that the observed market prices of individual trades of a company's stock (and thus its computed market capitalization) may not be representative of the fair value of the company as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity's individual common stock. In most industries, including the Company's, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest; therefore, a control premium was added to the Company's fair value calculations. This control premium was judgmental and based on observations of acquisitions in the industry.

Based on its analysis, the Company concluded that impairment of the entire amount of recorded goodwill for the Mid-Continent Deep reporting unit was required as of December 31, 2008. A $20.3 million before and after tax non-cash impairment of goodwill was recorded during the year ended December 31, 2008, which is included in "impairment of goodwill and long-lived assets" on the consolidated statement of operations.

(k) Revenue Recognition

Sales of oil and gas and NGL are recognized when oil, gas or NGL has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured, and the sales price is fixed or determinable. Virtually all of the Company's contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, gas and NGL, and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

Revenues are presented on a gross basis on the consolidated statement of operations. Production taxes are included in "taxes, other than income taxes" on the consolidated statements of operations and were approximately $47.2 million, $14.8 million and zero for the years ended December 31, 2008, 2007 and 2006, respectively.

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The Company has elected the entitlements method to account for gas production imbalances. Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Under the entitlements method, any amount received in excess of the Company's share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. At December 31, 2008 and 2007, the Company had gas production imbalance receivables of approximately $17.1 million and $17.7 million, respectively, which are included in "accounts receivable – trade, net" on the consolidated balance sheet and gas production imbalance payables of approximately $9.9 million and $11.5 million, respectively, which are included in "accounts payable and accrued expenses" on the consolidated balance sheets.

The Company engages in the purchase, gathering and transportation of third-party gas and subsequently markets such gas to independent purchasers under separate arrangements. As such, the Company separately reports third-party marketing sales and gas marketing expenses.

(l) Restricted Cash

Restricted cash of $1.3 million and $0.5 million is included in "other noncurrent assets, net" on the consolidated balance sheets at December 31, 2008 and 2007, respectively, and represents cash the Company has deposited into a separate account and designated for asset retirement obligations in accordance with contractual agreements.

(m) Derivative Instruments

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. These transactions are in the form of swap contracts, collars and put options. Additionally, the Company uses derivative financial instruments in the form of interest rate swaps to mitigate its interest rate exposure.

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 sheet as assets or liabilities. The Company accounts for its derivatives at fair value as an asset or liability and the change in the fair value of the derivatives is included in earnings since none of the Company's commodity or interest rate derivatives are designated as hedges under the provisions of SFAS 133. The Company determines the fair value of its derivative financial instruments in accordance with SFAS No. 157, "Fair Value Measurements" ("SFAS 157"), which defines fair value and establishes a framework for measuring fair value. The Company utilizes pricing models for significantly similar instruments to determine fair value. The models use a variety of techniques to arrive at fair value, including quotes and pricing analysis. See Note 9 and Note 10 for additional details about the Company's derivative financial instruments.

(n) Unit-Based Compensation

SFAS No. 123 (revised 2004), "Share-Based Payment" ("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 to employees and non-employee directors. The fair value of the unit-based payments, excluding liability awards, is computed at the date of grant and will not be remeasured. The fair value of liability awards is remeasured at each reporting date through the settlement date with the change in fair value recognized as compensation expense over that period. The Company currently does not have any awards accounted for as liability awards. SFAS 123R also requires the benefits of tax deductions in excess of recognized compensation costs to be reported as financing cash flow, rather than as an operating cash flow as required under prior guidance. This requirement will reduce net operating cash flows and increase net financing cash flows in periods in which such tax deduction exists. The Company had no excess tax deductions for any periods presented.

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The Company has made a policy decision, in accordance with the provisions of SFAS 123R, to recognize compensation cost for service-based awards on a straight-line basis over the requisite service period. The Company did not issue any unit-based compensation awards prior to January 2006. See Note 7 for a discussion of the Company's accounting for unit-based compensation expense.

(o) Deferred Financing Fees

The Company incurred legal and bank fees related to the issuance of debt (see Note 8). At December 31, 2008 and 2007, net deferred financing fees of approximately $11.9 million and $8.3 million, respectively, are included in "other noncurrent assets, net" on the consolidated balance sheets. These debt issuance costs are amortized over the life of the debt agreement. For the years ended December 31, 2008, 2007 and 2006, amortization expense of $5.2 million, $1.5 million and $1.1 million, respectively, is included in "interest expense, net of amounts capitalized" on the consolidated statements of operations. Deferred financing fees of approximately $6.7 million, $2.8 million and $3.3 million were written-off in connection with refinancings and debt extinguishments during the years ended December 31, 2008, 2007 and 2006, respectively, and are included in "other, net" on the consolidated statements of operations.

(p) Fair Value of Financial Instruments

The carrying values of the Company's receivables, payables and credit facility are estimated to be substantially the same as their fair values at December 31, 2008 and 2007. See Note 10 for fair value disclosures related to the Company's senior notes. As noted above, the Company determines the fair value of its derivative financial instruments in accordance SFAS 157. See Note 10 for details about the fair value of the Company's derivative financial instruments.

(q) Income Taxes

The Company is a limited liability company and treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, with income tax liabilities and/or benefits of the Company being passed through to the unitholders. As such, it is not a taxable entity, it does not directly pay federal and state income tax and recognition has not been given to federal and state income taxes for the operations of the Company except as described below.

Limited liability companies are subject to state income taxes in Texas. In addition, 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. See Note 16 for detail of amounts recorded in consolidated financial statements.

(2) Discontinued Operations and Dispositions

On July 1, 2008, the Company completed the sale of its interests in oil and gas properties located in the Appalachian Basin to XTO Energy, Inc. ("XTO") for a contract price of $600.0 million. Net proceeds were $566.5 million and the carrying value of net assets sold was $405.8 million, resulting in a gain on the sale of $160.7 million, which is recorded in "discontinued operations: gain (loss) on sale of assets, net of taxes" on the consolidated statement of operations. The Company used the net proceeds from the sale to repay loans outstanding under its term loan agreement and reduce indebtedness under its credit facility (see Note 8).

In addition, in March 2008, the Company exited the drilling and service business in the Appalachian Basin provided by its wholly owned subsidiary Mid Atlantic. At December 31, 2008, substantially all of the

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property and equipment previously held by Mid Atlantic totaling $9.2 million had been sold. During the year ended December 31, 2008, the Company recorded a loss on the sale of the Mid Atlantic assets of $1.6 million, which is recorded in "discontinued operations: gain (loss) on sale of assets, net of taxes" on the consolidated statement of operations.

The following summarizes the Appalachian Basin and Mid Atlantic amounts included in "income (loss) from discontinued operations, net of taxes" on the consolidated statements of operations:

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
Total revenues and other	$ 50,601	$ 67,110	$ 65,532
Total operating expenses	(23,677)	(54,260)	(37,594)
Interest expense	(13,401)	(23,156)	(19,948)
Income (loss) from discontinued operations	13,523	(10,306)	7,990
Income tax benefit	1,391	1,215	1,429
Income (loss) from discontinued operations, net of taxes	$ 14,914	$ (9,091)	$ 9,419

The Company computed interest expense related to discontinued operations in accordance with Emerging Issues Task Force Issue No. 87-24, "Allocation of Interest to Discontinued Operations" based on debt required to be repaid as a result of the disposal transaction.

On August 15, 2008, the Company completed the sale of certain properties in the Verden area in Oklahoma to Laredo Petroleum, Inc. ("Laredo") for a contract price of $185.0 million, subject to closing adjustments. Net proceeds and the carrying value of net assets sold were $169.4 million. The Verden assets were acquired by the Company with its acquisition of oil and gas properties from Dominion Resources, Inc. ("Dominion") in August 2007. The Company used the net proceeds from the sale to reduce indebtedness (see Note 8).

In addition, on December 4, 2008, the Company completed the sale of its deep rights in certain central Oklahoma acreage, which includes the Woodford Shale interval, to Devon Energy Production Company, LP ("Devon") for a contract price of $202.3 million, subject to closing adjustments. The sale included no producing reserves. Linn Energy retains the rights to the shallow portion of this acreage. Net proceeds were $153.2 million and the carrying value of net assets sold was $54.2 million, resulting in a gain on the sale of $99.0 million, which is recorded in "(gain) loss on sale of assets, net" on the consolidated statement of operations. In January 2009, certain post closing matters were resolved and the Company received additional proceeds of $11.5 million, which will be reported as a gain in the first quarter of 2009. Pending resolution of title issues, the Company estimates it may receive additional proceeds ranging from $12.0 million to $18.0 million during the first quarter of 2009. These assets were acquired by the Company with its acquisition of oil and gas properties from Dominion in August 2007. The Company used the net proceeds from the sale to reduce indebtedness (see Note 8).

(3) Acquisitions

The Company accounts for its acquisitions using the purchase method of accounting as prescribed in SFAS No. 141, "Business Combinations." On January 31, 2008, the Company completed the acquisition of certain oil and gas properties located primarily in the Mid-Continent Shallow region from Lamamco Drilling Company ("Lamamco") for a contract price of $552.2 million, subject to closing adjustments. The acquisition was financed with a combination of borrowings under the Company's credit facility and proceeds from a term loan entered into at closing (see Note 8).

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The following presents the purchase accounting for the acquisition, based on estimates of fair value (in thousands):

Cash	$ 537,253
Estimated transaction costs	966
	538,219
Fair value of liabilities assumed	4,029
Total purchase price	$ 542,248

The following presents the allocation of the purchase price for the acquisition, based on estimates of fair value (in thousands):

Current assets	$ 1,811
Oil and gas properties	538,328
Other property and equipment	2,109
	$ 542,248

The purchase price and purchase price allocation above are based on reserve reports, published 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 estimates of oil and gas reserves. 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.

The following unaudited pro forma financial information presents a summary of Linn Energy's consolidated results of continuing operations for the years ended December 31, 2008 and 2007, assuming the acquisition of assets from Lamamco had been completed as of January 1, 2007, including adjustments to reflect the allocation of the purchase price to the acquired net assets. The pro forma financial information also assumes that the following 2007 acquisitions were completed as of January 1, 2007:

- February 1, 2007, acquisition of certain oil and gas properties and related assets in the Mid-Continent Shallow region, in the Texas Panhandle, from Stallion Energy LLC, acting as general partner for Cavallo Energy, LP, for a contract price of $415.0 million

- June 12, 2007, acquisition of certain oil and gas properties in the Mid-Continent Shallow region, in the Texas Panhandle, for a contract price of $90.5 million

- August 31, 2007, acquisition of certain oil and gas properties in the Mid-Continent Deep region, in Oklahoma, Kansas and the Texas Panhandle from Dominion for a contract price of $2.05 billion

The revenues and expenses of the above assets are included in the consolidated results of the Company as of February 1, 2007, June 12, 2007 and September 1, 2007. The revenues and expenses of the assets acquired from Lamamco are included in the consolidated results of the Company effective February 1,

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2008. The pro forma financial information is not necessarily indicative of the results of operations if the acquisitions had been effective as of January 1, 2007. All amounts reflect continuing operations.

	Year Ended December 31, 2008	Year Ended December 31, 2007
	(in thousands, except per unit amounts)	
Total revenues and other	$ 1,444,304	$ 236,641
Total operating expenses	$ 442,406	$ 376,941
Income (loss) from continuing operations	$ 826,663	$ (290,641)
Income (loss) from continuing operations per unit:		
Units – basic	$ 7.24	$ (4.21)
Units – diluted	$ 7.24	$ (4.21)

(4) Goodwill

Goodwill was recorded in conjunction with the Company's acquisition of assets from Dominion in August 2007 (see Note 3).

The following reflects the changes in the carrying amount of goodwill during the years ended December 31, 2008 and 2007 (in thousands):

Balance, December 31, 2006	$ —
Acquisition of assets from Dominion	64,419
Balance, December 31, 2007	64,419
Purchase accounting adjustments:	
Post closing statement and other	25,424
Verden assets (1)	(18,231)
Woodford Shale assets (1)	(51,319)
Impairment (2)	(20,293)
Balance, December 31, 2008	$ —

(1) Represents update to preliminary purchase accounting in which amounts were allocated to unproved oil and gas properties and subsequently sold (see Note 2).

(2) See Note 1 for details about the Company's impairment analysis.

(5) Unitholders' Capital

Unit Repurchase Plan

In October 2008, the Board of Directors of the Company authorized the repurchase of up to $100.0 million of the Company's outstanding units. During the year ended December 31, 2008, 1,076,900 units were purchased at an average unit price of $12.09, for a total cost of approximately $13.0 million. All units were subsequently canceled. The Company may purchase units from time to time on the open market or in negotiated purchases. The timing and amounts of any such repurchases will be at the discretion of management, subject to market conditions and other factors, and will be in accordance with applicable securities laws and other legal requirements. The repurchase plan does not obligate the Company to acquire any specific number of units and may be discontinued at any time. Units are purchased at fair market value on the date of purchase.

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Issuance and Cancellation of Units

During the year ended December 31, 2008, the Company issued 410,000 units in connection with the termination of certain contractual obligations (equal to a fair value of approximately $8.7 million). In addition, during year ended December 31, 2008, the Company issued 600,000 units in connection with the acquisition of certain gas properties (equal to a fair value of approximately $14.7 million). During the year ended December 31, 2008, the Company purchased 94,521 units for approximately $2.0 million in conjunction with units received by the Company for the payment of withholding taxes due on units issued under its equity compensation plan (see Note 7). All units were subsequently canceled.

During the year ended December 31, 2007, the Company issued 77,381 units in connection with the acquisition of royalty interests in certain oil and gas properties. In addition, during the year ended December 31, 2007, the Company purchased 226,561 units for approximately $7.4 million in conjunction with units received by the Company for the payment of withholding taxes due on units issued under its equity compensation plan (see Note 7). All units were subsequently canceled.

Private Placements

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 August 2007 acquisition of certain oil and gas properties in the Mid-Continent Deep region (see Note 3). The Class D units were converted to units on a one-for-one basis in November 2007.

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.

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 acquisition of certain oil and gas properties. The Class C units were converted into units on a one-for-one basis in April 2007.

In October 2006, the Company closed its private placement of $305.0 million of units to a group of institutional investors, consisting of 9,185,965 Class B units at a price of $20.55 per unit, and 5,534,687 units at a price of $21.00 per unit. Proceeds, net of expenses were $304.7 million and were used to repay indebtedness. The Class B units were converted into units on a one-for-one basis in January 2007.

Registration Statements covering all the units issued through the private placements noted above were filed and declared effective by the Securities and Exchange Commission (“SEC”) during December 2007. In December 2007, the Company was required to pay purchasers in the June 2007 private placement approximately $0.7 million in liquidated damages as specified in the registration rights agreement because the registration effectiveness deadline in the agreement was not achieved. This payment is included in “general and administrative expenses” on the consolidated statement of operations for the year ended December 31, 2007.

Initial Public Offering

During the year ended December 31, 2006, the Company completed its IPO of 12,450,000 units representing limited liability interest in the Company at $21.00 per unit, for net proceeds, after underwriting discounts of $18.3 million and offering expenses of $4.3 million, of $238.8 million, of which $122.0 million was used to reduce indebtedness and $114.4 million was used to redeem a portion of membership interests in the Company and units held by certain holders and approximately $2.0 million was used to pay bonuses to certain executive officers of the Company.

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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. Distributions paid by the Company are presented on the consolidated statements of unitholders' capital (deficit). In January 2009, the Company's Board of Directors declared a cash distribution of $0.63 per unit with respect to the fourth quarter of 2008. The distribution totaled approximately $72.5 million and was paid on February 13, 2009 to unitholders of record as of the close of business on February 6, 2009.

(6) 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, since it has not experienced credit losses on such sales. The Company routinely assesses the recoverability of all material trade and other receivables to determine collectibility (see Note 1).

For the year ended December 31, 2008, the Company's three largest customers represented 21%, 18% and 10% of the Company's sales. For the year ended December 31, 2007, the Company's two largest customers represented 27% and 22% of the Company's sales. The Company's largest customer represented approximately 81% of the Company's sales for the year ended December 31, 2006.

At December 31, 2008, 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 December 31, 2008, trade accounts receivable from the Company's two largest customers represented approximately 20% and 16% of the Company's receivables. At December 31, 2007, three customers' trade accounts receivable from oil, gas and NGL sales accounted for more than 10% of the Company's total trade accounts receivable. At December 31, 2007, trade accounts receivable from the Company's three largest customers represented approximately 22%, 13% and 12% of the Company's receivables.

(7) Unit-Based Compensation and Other Benefit Plans

Incentive Plan Summary

The Amended and Restated Linn Energy, LLC Long-Term Incentive Plan (the "Plan") originally became effective in December 2005. The Plan, which is administered by the Compensation Committee of the Board of Directors, permits the granting of unit grants, unit options, restricted units, phantom units and unit appreciation rights to employees, consultants and non-employee directors under the terms of the Plan. The unit options and restricted units vest ratably over three years. The contractual life of unit options is ten years. Unit awards were issued for the first time in January 2006, in conjunction with the Company's IPO.

The Plan limits the number of units that may be delivered pursuant to awards to 12.2 million units. The Board of Directors and the Compensation Committee of the Board of Directors have the right to alter or amend the Plan or any part of the Plan from time to time, including increasing the number of units that may be granted, subject to unitholder approval as required by the exchange upon which the units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the benefits to the participant without the consent of the participant.

Upon exercise or vesting of an award of, or settled in, units, the Company will issue new units, acquire units on the open market or directly from any person or use any combination of the foregoing, at the Compensation Committee's discretion. If the Company issues new units upon exercise or vesting of an award of, or settled in, units, the total number of units outstanding will increase. To date, the Company has issued awards of unit grants, unit options, restricted units and phantom units. The Plan provides for all of the following types of awards:

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

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

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

Phantom Units/Unit Appreciation Rights These awards may be settled in units, cash or a combination thereof. Such grants will contain terms as determined by the Compensation Committee, including the period or terms over which phantom units will vest. If a grantee's employment or service relationship terminates for any reason, the grantee's phantom units or unit appreciation rights will be automatically forfeited unless, and to the extent, the Compensation Committee or the terms of the award agreement provide otherwise. While phantom units require no payment from the grantee, unit appreciation rights will have an exercise price that will not be less than the fair market value of the units on the date of grant. At December 31, 2008, the Company had 36,784 phantom units issued and outstanding. To date, the Company has not issued unit appreciation rights.

Securities Authorized for Issuance Under the Plan

As of December 31, 2008, approximately 1,590,438 units were issuable under the Plan pursuant to outstanding award or other agreements and an additional 8,278,115 units were reserved for future issuance under the Plan.

Accounting for Unit-Based Compensation

Activities and balances presented in this Note 7 include amounts associated with discontinued operations (see Note 2). The Company recognizes as expense, beginning at the grant date, the fair value of unit options and other equity-based compensation issued to employees and non-employee directors. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period using the straight-line method in the Company's consolidated statement of operations.

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For the years ended December 31, 2008, 2007 and 2006, the Company recorded unit-based compensation expense of approximately $15.7 million, $12.5 million and $21.6 million, respectively, as a charge against income before income taxes and it is included in "lease operating expenses," "general and administrative expenses" or "income (loss) from discontinued operations, net of taxes" on the consolidated statements of operations. Approximately $14.7 million, $12.1 million and $21.6 million of expense is included in results of continuing operations for the years ended December 31, 2008, 2007 and 2006, respectively. No related income tax benefit was recognized due to non-deductibility and recognition of a valuation allowance (see Note 16).

Restricted/Unrestricted Units

The fair value of unrestricted unit grants and restricted units issued is determined based on the fair market value of the Company units on the date of grant. A summary of the status of the non-vested units as of December 31, 2008, is presented below:

	Number of Non-vested Units		Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2007	833,820	$	29.43
Granted	589,770	$	23.82
Vested	(502,523)	$	27.94
Forfeited	(86,063)	$	23.18
Non-vested units at December 31, 2008	835,004	$	27.01

The weighted-average grant-date fair value of unrestricted unit grants and restricted units granted during the years ended December 31, 2007 and 2006 was $31.16 and $22.98, respectively.

As of December 31, 2008, there was approximately $13.0 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of approximately 1.21 years. The total fair value of units that vested was approximately $14.0 million, $19.4 million and $2.4 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Changes in Unit Options and Unit Options Outstanding

The following provides information related to unit option activity for the year ended December 31, 2008:

	Number of Units Underlying Options		Weighted Average Exercise Price Per Unit		Weighted Average Grant Date Fair Value	Weighted Average Remaining Contractual Life in Years
Outstanding at December 31, 2007	997,021	$	24.68	$	4.67	
Granted	691,000	$	23.26	$	2.58	
Exercised	(1,333)	$	21.00	$	4.24	
Forfeited	(96,250)	$	25.17	$	4.70	
	1,590,438	$	24.04	$	3.76	8.23

Outstanding at December 31, 2008						
Exercisable at December 31, 2008	724,490	$	24.32	$	4.49	7.71

The weighted-average grant-date fair value of options granted during the years ended December 31, 2007 and 2006 was $4.59 and $3.59, respectively. The total intrinsic value of options exercised during the years ended December 31, 2008 and 2007 was approximately $4,000 and $95,000, respectively. No options were exercised during the year ended December 31, 2006.

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As of December 31, 2008, there was approximately $1.6 million of total unrecognized compensation cost related to non-vested unit options. The cost is expected to be recognized over a weighted average period of approximately 1.22 years. At December 31, 2008, exercisable unit options and all outstanding unit options had no aggregate intrinsic value. The total fair value of all options that vested during the years ended December 31, 2008, 2007 and 2006 was approximately $2.1 million, $1.5 million and $76,000, respectively. No options expired during the years ended December 31, 2008, 2007 or 2006.

The fair value of unit-based compensation for unit options was estimated on the date of grant using a Black-Scholes pricing model based on certain assumptions. The Company's determination of the fair value of unit-based payment awards is affected by the Company's unit price as well as assumptions regarding a number of complex and subjective variables. The Company's employee unit options have various restrictions including vesting provisions and restrictions on transfers and hedging, among others, and often are expected to be exercised prior to their contractual maturity.

Expected volatilities used in the estimation of fair value have been determined using available volatility data for the Company as well as an average of volatility computations of other identified peer companies in the oil and gas industry. Expected distributions are estimated based on the Company's distribution rate at the date of grant. Historical data of the Company and other identified peer companies is used to estimate expected term because, due to the limited period of time its equity units have been publicly traded, the Company does not have sufficient historical exercise data to compute a reasonable estimation. Forfeitures are estimated using historical Company data and are revised, if necessary, in subsequent periods if actual forfeitures differ from estimates. All employees granted awards have been determined to have similar behaviors for purposes of determining the expected term used to estimate fair value. The risk-free rate for periods within the expected term of the unit option is based on the United States Treasury yield curve in effect at the time of grant. The fair values of the unit option grants were based upon the following assumptions:

	2008		2007		2006	
Expected volatility	30.59%	– 34.57%	30.40%	– 35.58%	29.70%	– 31.30%
Expected distributions	10.13%	– 12.32%	6.51%	– 10.67%	7.20%	– 8.50%
Risk free rate	2.66%	– 3.41%	3.53%	– 5.18%	4.31%	– 5.04%
Expected term	5.0 years		5.0 years		5.0 years	

Although the fair value of unit option grants is determined in accordance with SFAS 123R using a Black-Scholes option-pricing model, that value may not be indicative of the fair value observed in a willing buyer/willing seller market transaction.

Non-Employee Grants

During the year ended December 31, 2007, the Company granted an aggregate 150,000 unit warrants to certain individuals in connection with an acquisition transition services agreement. The unit warrants have an exercise price of $25.50 per unit warrant, are fully exercisable at December 31, 2008, 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. The expense of approximately $1.4 million is included in "general and administrative expenses" on the consolidated statement of operations for the year ended December 31, 2007.

Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan for eligible employees. Company contributions to the 401(k) plan consist of a discretionary matching contribution equal to 100% of the first 4% of eligible compensation contributed by the employee on a before-tax basis. The Company contributed approximately $1.6 million, $0.8 million and $0.2 million during the years ended December 31, 2008, 2007 and 2006, respectively, to the 401(k) plan's trustee account. The 401(k) plan funds are held in a trustee account on behalf of the plan participants.

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(8) Debt

At December 31, 2008 and 2007, the Company had the following debt outstanding:

	December 31, 2008	2007
	(in thousands)	
Credit facility (1)	$ 1,403,393	$ 1,443,000
Senior notes, net (2)	250,175	
Less current maturities		
	$ 1,653,568	$ 1,443,000

(1) Variable interest rate of 2.47% and 7.02% at December 31, 2008 and 2007, respectively.

(2) Fixed interest rate of 9.875% and effective interest rate of 10.25%; net of unamortized discount of approximately $5.8 million at December 31, 2008.

Credit Facility

At December 31, 2008, the Company had a $1.85 billion borrowing base under its Third Amended and Restated Credit Agreement ("Credit Facility") with a maturity of August 2010. 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. Significant declines in oil, gas or NGL prices may result in a decrease in the borrowing base. During 2009, the Company plans to renegotiate its Credit Facility, which is anticipated to result in increased interest expense. There can be no assurance that the borrowing base under a new Credit Facility will remain at the current level.

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 the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.00% and 1.75% per annum or the alternate base rate ("ABR") plus an applicable margin between 0% and 0.25% per annum. Interest is generally payable quarterly for ABR loans and at the applicable maturity date for LIBOR loans. The Company is required to pay a fee ranging from 0.3% to 0.375% per year on the unused portion of the Credit Facility.

The Credit Facility contains various covenants 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 that require the Company to maintain adjusted earnings to interest expense and current liquidity financial ratios. The Company is in compliance with all financial and other covenants of its Credit Facility.

Certain subsidiaries of Lehman Brothers Holdings Inc. ("Lehman Holdings"), including Lehman Brothers Commodity Services Inc. ("Lehman Commodity Services"), were lenders in the Company's Credit Facility. In September 2008 and

October 2008, Lehman Holdings and Lehman Commodity Services, respectively, filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code (see Note 13). In October 2008, the Company replaced Lehman Holdings' subsidiaries with another lender and Lehman Holdings' subsidiaries no longer participate in the Company's Credit Facility. At December 31, 2008, available borrowing under the Credit Facility was $440.2 million, which includes a $6.4 million reduction in availability for outstanding letters of credit. Available borrowing under the Credit Facility was $415.4 million at January 30, 2009 which includes a $6.2 million reduction in availability for outstanding letters of credit.

Term Loan

On January 31, 2008, in order to fund a portion of the January 2008 acquisition of oil and gas properties in the Mid-Continent Shallow region (see Note 3), the Company entered into a $400.0 million Second Lien Term Loan Agreement ("Term Loan") maturing on July 31, 2009. Interest was determined by reference to LIBOR plus an applicable margin of 5.0% for the first twelve months and 7.5% for the remaining period until maturity, or by reference to a domestic bank rate plus an applicable margin of 3.5% for the first twelve months and 6.0% for the remaining period until maturity. On June 30, 2008, the Company repaid $243.6 million in indebtedness under the Term Loan with net proceeds from the Senior Notes (see below). On July 1, 2008, the Company repaid the balance of the Term Loan of $156.4 million. Deferred financing fees associated with the Term Loan of approximately $4.6 million were written off during the year ended December 31, 2008.

Senior Notes

On June 24, 2008, the Company entered into a purchase agreement with a group of initial purchasers ("Initial Purchasers") pursuant to which the Company agreed to issue $255.9 million in aggregate principal amount of the Company's senior notes due 2018 ("Senior Notes"). The Senior Notes were offered and sold to the Initial Purchasers and then resold to qualified institutional buyers each in transactions exempt from the registration requirements under the Securities Act of 1933, as amended ("Securities Act"). The Company used the net proceeds (after deducting the Initial Purchasers' discounts and offering expense) of approximately $243.6 million to repay loans outstanding under the Company's Term Loan (see above). In connection with the Senior Notes, the Company incurred financing fees of approximately $7.8 million, which will be amortized over the life of the Senior Notes; the expense is recorded in "interest expense, net of amounts capitalized" on the consolidated statement of operations. The $5.9 million discount on the Senior Notes will be amortized over the life of the Senior Notes; the expense is recorded in "interest expense, net of amounts capitalized" on the consolidated statement of operations. See Note 10 for fair value disclosures related to the Senior Notes.

The Senior Notes were issued under an Indenture dated June 27, 2008 ("Indenture"), mature on July 1, 2018 and bear interest at 9.875%. Interest is payable semi-annually beginning January 1, 2009. The Senior Notes are general unsecured senior obligations of the Company and are effectively junior in right of payment to any secured indebtedness of the Company to the extent of the collateral securing such indebtedness. Each of the Company's material subsidiaries guaranteed the Senior Notes on a senior unsecured basis. The Indenture provides that the Company may redeem: (i) on or prior to July 1, 2011, up to 35% of the aggregate principal amount of the Senior Notes at a redemption price of 109.875% of the principal amount, plus accrued and unpaid interest; (ii) prior to July 1, 2013, all or part of the Senior Notes at a redemption price equal to the principal amount, plus a make whole premium (as defined in the Indenture) and accrued and unpaid interest; and (iii) on or after July 1, 2013, all or part of the Senior Notes at redemption prices equal to 104.938% in 2013, 103.292% in 2014, 101.646% in 2015 and 100% in 2016 and thereafter. The Indenture also provides that, if a change of control (as defined in the Indenture) occurs, the holders have a right to require the Company to repurchase all or part of the Senior Notes at a redemption price equal to 101%, plus accrued and unpaid interest.

The Senior Notes' Indenture contains covenants that, among other things, limit the Company's ability to: (i) pay distributions on, purchase or redeem the Company's units or redeem its subordinated debt; (ii) make investments; (iii) incur or guarantee additional indebtedness or issue certain types of equity securities; (iv) create certain liens; (v) sell assets; (vi) consolidate, merge or transfer all or substantially all of the Company's assets; (vii) enter into agreements that restrict distributions or other payments from the Company's restricted subsidiaries to the Company;

(viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries.

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In connection with the issuance and sale of the Senior Notes, the Company entered into a Registration Rights Agreement ("Registration Rights Agreement") with the Initial Purchasers. Under the Registration Rights Agreement, the Company agreed to use its reasonable best efforts to file with the SEC and cause to become effective a registration statement relating to an offer to issue new notes having terms substantially identical to the Senior Notes in exchange for outstanding Senior Notes. In certain circumstances, the Company may be required to file a shelf registration statement to cover resales of the Senior Notes. The Company will not be obligated to file the registration statements described above if the restrictive legend on the Senior Notes has been removed and the Senior Notes are freely tradable (in each case, other than with respect to persons that are affiliates of the Company) pursuant to Rule 144 under the Securities Act, as of the 366th day after the Senior Notes were issued. If the Company fails to satisfy its obligations under the Registration Rights Agreement, the Company may be required to pay additional interest to holders of the Senior Notes under certain circumstances.

(9) Derivatives

Commodity Derivatives

The Company sells oil, gas and NGL in the normal course of its business and utilizes derivative instruments to minimize the variability in cash flows due to price movements in oil, gas and NGL. The Company enters into derivative instruments such as swap contracts, collars and put options to economically hedge a portion of its forecasted oil, gas and NGL sales. Oil puts are also used to economically hedge NGL sales. The Company did not designate these contracts as cash flow hedges under SFAS 133; therefore, the changes in fair value of these instruments are recorded in current earnings. See Note 10 for additional disclosures about oil and gas commodity derivatives as required by SFAS 157.

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The following table summarizes open positions as of December 31, 2008 and represents, as of such date, derivatives in place through December 31, 2014, on annual production volumes:

	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014
Gas Positions:						
Fixed Price Swaps:						
Hedged Volume (MMMBtu)	39,586	39,566	31,901	29,662		
Average Price ($/MMBtu)	$ 8.53	$ 8.20	$ 8.27	$ 8.46	$	$
Puts:						
Hedged Volume (MMMBtu)	6,960	6,960	6,960			
Average Price ($/MMBtu)	$ 7.50	$ 7.50	$ 7.50	$	$	$
PEPL Puts: (1)						
Hedged Volume (MMMBtu)	5,334	10,634	13,259	5,934		
Average Price ($/MMBtu)	$ 7.85	$ 7.85	$ 7.85	$ 7.85	$	$
Total:						
Hedged Volume (MMMBtu)	51,880	57,160	52,120	35,596		
Average Price ($/MMBtu)	$ 8.32	$ 8.05	$ 8.06	$ 8.36	$	$
Oil Positions:						
Fixed Price Swaps:						
Hedged Volume (MBbls)	2,437	2,150	2,073	2,025	2,275	2,200
Average Price ($/Bbl)	$ 90.00	$ 90.00	$ 84.22	$ 84.22	$ 84.22	$ 84.22
Puts: (2)						
Hedged Volume (MBbls)	1,843	2,250	2,352	500		
Average Price ($/Bbl)	$ 120.00	$ 110.00	$ 69.11	$ 77.73	$	$
Collars:						
Hedged Volume (MBbls)	250	250	276	348		
Average Floor Price ($/Bbl)	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$	$
Average Ceiling Price ($/Bbl)	$ 114.25	$ 112.00	$ 112.25	$ 112.35	$	$
Total:						
Hedged Volume (MBbls)	4,530	4,650	4,701	2,873	2,275	2,200
Average Price ($/Bbl)	$ 102.21	$ 99.68	$ 77.00	$ 83.79	$ 84.22	$ 84.22
Gas Basis Differential Positions:						
PEPL Basis Swaps:						
Hedged Volume (MMMBtu)	46,916	43,166	35,541	34,066	31,700	
Hedged Differential ($/MMBtu)	$ (0.97)	$ (0.97)	$ (0.96)	$ (0.95)	$ (1.01)	$

(1)

Settle on the Panhandle Eastern Pipeline (“PEPL”) spot price of gas to hedge basis differential associated with gas production in the Mid-Continent Deep and Mid-Continent Shallow regions.

(2) The Company utilizes oil puts to hedge revenues associated with its NGL production.

Settled derivatives on gas production for the year ended December 31, 2008 included a volume of 50,730 MMMBtu at an average contract price of $8.49. Settled derivatives on oil and NGL production for the year ended December 31, 2008 included a volume of 4,421 MBbls at an average contract price of $77.67. The gas derivatives are settled based on 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 derivatives are settled based on the average month’s daily NYMEX price of light oil and settlement occurs on the final day of the production month.

Interest Rate Swaps

The Company has entered into interest rate swap agreements based on LIBOR to minimize the effect of fluctuations in interest rates. If LIBOR is lower than the fixed rate in the contract, the Company is required

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to pay the counterparties the difference, and conversely, the counterparties are required to pay the Company if LIBOR 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 No. 133; therefore, the changes in fair value of these instruments are recorded in current earnings. See Note 10 for additional disclosures about interest rate swaps as required by SFAS 157.

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

	Year 2009	Year 2010	Year 2011 (1)
		(dollars in thousands)	
Notional Amount	$ 1,212,000	$ 1,212,000	$ 1,212,000
Fixed Rate	5.06%	5.06%	5.06%

(1) Represents interest rate swaps that settle in January 2011.

In January 2009, the Company amended and extended its interest rate swap portfolio. The Company canceled, in a cashless transaction, its existing interest rate swap agreements and entered into new agreements that settle at a fixed rate of 3.80% through 2014. The following presents the settlement terms of the new interest rate swaps:

	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014 (1)
			(dollars in thousands)			
Notional Amount	$ 1,250,000	$ 1,250,000	$ 1,250,000	$ 1,250,000	$ 1,250,000	$ 1,250,000
Fixed Rate	3.80%	3.80%	3.80%	3.80%	3.80%	3.80%

(1) Represents interest rate swaps that settle in January 2014.

Outstanding Notional Amounts

The following presents the outstanding notional amounts and maximum number of months outstanding of derivative instruments:

	December 31, 2008	2007
Outstanding notional amounts of gas contracts (MMMBtu)	196,756	275,769
Maximum number of months gas contracts outstanding	48	59
Outstanding notional amounts of oil contracts (MBbls)	21,229	16,214
Maximum number of months oil contracts outstanding	72	72
Outstanding notional amount of interest rate swaps (in thousands)	$ 1,212,000	$ 1,212,000
Maximum number of months interest rate swaps outstanding	24	36

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Balance Sheet Presentation

The Company's commodity derivatives and interest rate swap derivatives are presented on a net basis in "derivative instruments" on the consolidated balance sheets. The following summarizes the fair value of derivatives outstanding on a gross basis:

	December 31, 2008	2007
	(in thousands)	
Assets:		
Commodity derivatives	$ 977,847	$ 246,124
Interest rate swaps		2,548
	$ 977,847	$ 248,672
Liabilities:		
Commodity derivatives	$ 119,124	$ 260,058
Interest rate swaps	82,422	32,475
	$ 201,546	$ 292,533

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, 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's counterparties are participants in its Credit Facility (see Note 8) which is secured by the Company's oil and gas reserves; therefore, the Company is not required to post any collateral. The Company does not require collateral from the counterparties. The maximum amount of loss due to credit risk that the Company would incur if its counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $977.8 million at December 31, 2008. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that are also lenders in the Company's Credit Facility, each of which currently meet the Company's minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis. In accordance with the Company's standard practice, its commodity and interest rate swap derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of such loss is somewhat mitigated at December 31, 2008. See Note 13 for details about canceled commodity contracts with Lehman Commodity Services.

Gain (Loss) on Derivatives

Gains and losses on derivatives are reported on the consolidated statement of operations in "gain (loss) on oil and gas derivatives" and "gain (loss) on interest rate swaps" and include realized and unrealized gains (losses). Realized gains (losses), excluding canceled commodity derivatives, represent amounts related to the settlement of derivative instruments, and for commodity derivatives, are aligned with the underlying production. Unrealized gains (losses) represent the change in fair value of the derivative instruments and are non-cash items.

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The following presents the Company's reported gains and losses on derivative instruments:

	Year Ended December 31, 2008	2007	2006
		(in thousands)	
Realized gains (losses):			
Commodity derivatives	$ 9,408	$ 37,250	$ 20,160
Canceled commodity derivatives	(81,358)		
Interest rate swaps	(16,036)	1,467	281
	$ (87,986)	$ 38,717	$ 20,441
Unrealized gains (losses):			
Commodity derivatives	$ 734,732	$ (382,787)	$ 83,148
Interest rate swaps	(50,638)	(29,548)	82
	$ 684,094	$ (412,335)	$ 83,230
Total gains (losses):			
Commodity derivatives	$ 662,782	$ (345,537)	$ 103,308
Interest rate swaps	(66,674)	(28,081)	363
	$ 596,108	$ (373,618)	$ 103,671

During the year ended December 31, 2008, the Company canceled (before the contract settlement date) derivative contracts on estimated future gas production resulting in realized losses of $81.4 million. The future gas production under the canceled contracts primarily related to properties in the Appalachian Basin and Verden areas (see Note 2).

In addition, in September 2008, the Company canceled (before the contract settlement date) all of its commodity derivative contracts with Lehman Commodity Services as counterparty. The Company entered into contracts for substantially the same volumes at identical strike prices with another participant in its Credit Facility for a cost of approximately $67.6 million. As a result, effective September 17, 2008, Lehman Commodity Services was no longer a counterparty to any of the Company's commodity derivative contracts and the Company's overall derivative positions are unchanged. See Note 13 for details about the Company's receivable for the canceled derivative contracts from Lehman Commodity Services.

(10) Fair Value of Financial Instruments

The Company accounts for its oil and gas commodity derivatives and interest rate swaps at fair value (see Note 9) on a recurring basis. Effective January 1, 2008, the Company adopted SFAS 157 for these financial instruments. SFAS 157 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value, and enhances disclosure requirements for fair value measurements. The impact of the adoption of SFAS 157 to the Company's results of operations was a decrease in net income of approximately $4.0 million, or $0.04 per unit, for the year ended December 31, 2008, resulting from assumed credit risk adjustments. The credit risk adjustments are based on published credit ratings, public bond yield spreads and credit default swap spreads. The impact of the Company's assumed credit risk adjustment was a gain of approximately $8.9 million. The impact of the counterparties' assumed credit risk adjustment was a loss of approximately $12.9 million.

The fair value of derivative instruments is determined utilizing pricing models for significantly similar instruments. The models use a variety of techniques to arrive at fair value, including quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward curves generated from a compilation of data gathered from third parties.

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Fair Value Hierarchy

In accordance with SFAS 157, the Company has categorized its financial instruments, based on the priority of inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Financial assets and liabilities recorded on the consolidated balance sheet are categorized based on the inputs to the valuation techniques as follows:

Level 1 Financial assets and liabilities for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access.

Level 2 Financial assets and liabilities for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability (commodity derivatives and interest rate swaps).

Level 3 Financial assets and liabilities for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

As required by SFAS 157, when the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. The Company conducts a review of fair value hierarchy classifications on a quarterly basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities.

The following presents the Company's fair value hierarchy for assets and liabilities measured at fair value on a recurring basis at December 31, 2008. These items are included in "derivative instruments" on the consolidated balance sheet.

	Fair Value Measurements on a Recurring Basis December 31, 2008		
	Level 2	Netting (1)	Total
		(in thousands)	
Assets:			
Commodity derivatives	$ 977,847	$ (115,191)	$ 862,656
Interest rate swaps	$	$	$
Liabilities:			
Commodity derivatives	$ 119,124	$ (115,191)	$ 3,933
Interest rate swaps	$ 82,422	$	$ 82,422

(1) Represents counterparty netting under derivative netting agreements.

At December 31, 2008, the Company also had Senior Notes with a net carrying value of $250.2 million (see Note 8) and a fair value of $147.3 million. The fair value of the Senior Notes was estimated based on prices quoted from third-party financial institutions.

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(11) Other Property and Equipment

Other property and equipment consists of the following:

	December 31, 2008	2007
	(in thousands)	
Gas compression plant and pipeline	$ 87,133	$ 112,182
Land	848	1,052
Buildings and leasehold improvements	7,382	8,510
Vehicles	4,121	7,405
Drilling and other equipment	4,708	12,313
Furniture and office equipment	7,267	8,127
	111,459	149,589
Less accumulated depreciation	(13,171)	(12,150)
	$ 98,288	$ 137,439

(12) Asset Retirement Obligations

Asset retirement obligations ("ARO") associated with retiring tangible long-lived assets, are recognized as a liability in the period in which a legal obligation is incurred and becomes determinable. This liability is offset by a corresponding increase in the carrying amount of the underlying asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the cost of the ARO is recognized over the useful life of the asset. The ARO is recorded at fair value, and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. The fair value of ARO is measured using expected future cash outflows discounted at the Company's average credit-adjusted risk-free interest rate (7.8%, 7.0% and 7.0% for the years ended December 31, 2008, 2007 and 2006, respectively).

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the asset balance.

The following presents a reconciliation of the ARO liability:

	December 31, 2008	2007
	(in thousands)	
ARO at beginning of year	$ 29,073	$ 8,594
Liabilities added related to acquisitions and drilling	5,939	15,922
Liabilities associated with assets sold	(8,020)	
Current year accretion expense	1,967	1,014
Settlements	(37)	
Revision of estimates		3,543
ARO at end of year	$ 28,922	$ 29,073

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(13) Commitments and Contingencies

On September 15, 2008, Lehman Holdings filed a voluntary petition for reorganization under Chapter 11 of the United States Bankruptcy Code (“Chapter 11”) with the United States Bankruptcy Court for the Southern District of New York (the “Court”). On October 3, 2008, Lehman Commodity Services also filed a voluntary petition for reorganization under Chapter 11 with the Court. As of December 31, 2008, the Company had a receivable of approximately $67.6 million from Lehman Commodity Services for canceled derivative contracts (see Note 9). The Company is pursuing various legal remedies to protect its interests. Based on market expectations, at December 31, 2008, the Company estimated approximately $6.7 million of the receivable balance to be collectible. The net receivable of approximately $6.7 million is included in “other current assets, net” on the consolidated balance sheet at December 31, 2008. The related expense is included in "gain (loss) on oil and gas derivatives" on the consolidated statement of operations for the year ended December 31, 2008. The Company believes that the ultimate disposition of this matter will not have a material adverse effect on its business, financial position, results of operations or liquidity.

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 material adverse effect on its business, financial position, results of operations or liquidity.

(14) Earnings Per Unit

Basic earnings per unit is computed in accordance with SFAS No. 128, “Earnings Per Share” (“SFAS 128”) 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. At December 31, 2006, the Company had two classes of units outstanding: (i) units representing limited liability company interests (“units”) listed on The NASDAQ Global Market under the symbol “LINE” and (ii) Class B units.

In accordance with SFAS 128, dual presentation of basic and diluted earnings per unit has been presented in the consolidated statement of operations for the year ended December 31, 2006 for each class of units issued and outstanding at that date, units and Class B units. Net income per unit was allocated to the units and the Class B units on an equal basis. Certain existing holders of Linn Energy units totaling over 50% committed in advance to vote at a unitholder meeting in favor of the conversion of Class B units to units and the Class B units were converted to units on a one-for-one basis in January 2007; therefore, the Class B units share equally with the units in the net income of the Company. Since the Class B units were converted to units in January 2007, they share equally in the February 2007 distributions and all future distributions. The Company made no distributions to Class B unitholders during the period the Class B units were outstanding.

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The following table summarizes the calculation of basic and diluted net income (loss) per unit:

	Year Ended December 31,					
		2008		2007		2006
	(in thousands, except per unit amounts)					
Income (loss) from continuing operations	$	825,657	$	(356,194)	$	69,811
Income (loss) from discontinued operations		173,959		(8,155)		9,374
Net income (loss)	$	999,616	$	(364,349)	$	79,185
Weighted average units outstanding:						
Basic units outstanding		114,140		68,916		28,281
Dilutive effect of unit equivalents		116				2,104
Diluted units outstanding		114,256		68,916		30,385
Weighted average Class B units outstanding:						
Basic Class B units outstanding						1,737
Dilutive effect of unit equivalents						
Diluted Class B units outstanding						1,737
Income (loss) per unit – continuing operations:						
Units – basic	$	7.23	$	(5.17)	$	2.33
Units – diluted	$	7.23	$	(5.17)	$	2.30
Class B units – basic	$		$		$	2.33
Class B units – diluted	$		$		$	2.30
Income (loss) per unit – discontinued operations:						
Units – basic	$	1.53	$	(0.12)	$	0.31
Units – diluted	$	1.52	$	(0.12)	$	0.31
Class B units – basic	$		$		$	0.31
Class B units – diluted	$		$		$	0.31
Net income (loss) per unit:						
Units – basic	$	8.76	$	(5.29)	$	2.64
Units – diluted	$	8.75	$	(5.29)	$	2.61
Class B units – basic	$		$		$	2.64
Class B units – diluted	$		$		$	2.61

Basic units outstanding excludes the effect of average anti-dilutive common stock equivalents related to unit options and warrants and unvested restricted units of 2.2 million, 2.0 million and 0.2 million for the years ended December 31, 2008, 2007 and 2006, respectively. In addition, basic units outstanding excludes the effect of average anti-dilutive Class B units for the year ended December 31, 2006. All equivalent units were anti-dilutive for the year ended December 31, 2007, as the Company reported a loss from continuing operations.

(15) Operating Leases

The Company leases office space and other property and equipment under lease agreements expiring on various dates through 2015. The Company recognized expense under operating leases of approximately $3.2 million, $1.2 million and $0.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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As of December 31, 2008, future minimum lease payments were as follows (in thousands):

2009	$ 3,538
2010	3,682
2011	3,377
2012	3,237
2013	2,774
Thereafter	4,000
	$ 20,608

(16) Income Taxes

The Company is treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, with income tax liabilities and/or benefits of the Company being passed through to the unitholders. As such, it is not a taxable entity, it does not directly pay federal and state income tax and recognition has not been given to federal and state income taxes for the operations of the Company except as described below. Its taxable income or loss, which may vary substantially from the net income or net loss reported in the consolidated statement of operations, is includable in the federal and state income tax returns of each unitholder. The aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as the Company does not have access to information about each unitholder's tax attributes in the Company.

Certain of the Company's subsidiaries are Subchapter C-corporations subject to corporate income taxes. In addition, limited liability companies are subject to state income taxes in Texas. The income tax benefit (expense) from continuing operations consisted of the following:

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
Current taxes:			
Federal	$ (1,184)	$ (1,355)	$ —
State	(1,528)	(283)	(2)
Deferred taxes:			
Federal	—	(3,066)	1,594
State	—	(84)	381
	$ (2,712)	$ (4,788)	$ 1,973

As of December 31, 2008, the Company's taxable entities had approximately $7.0 million of net operating loss carryforwards for federal income tax purposes, which will begin expiring in 2025.

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Income tax expense differed from amounts computed by applying the federal income tax rate of 35% to pre-tax income (loss) from continuing operations as a result of the following:

	Year Ended December 31,		
	2008	2007	2006
Federal statutory rate	35.0%	35.0%	35.0%
State, net of federal tax benefit	0.1	(0.1)	(0.6)
Income (loss) from non-taxable entities	(34.9)	(35.3)	(50.2)
Non-deductible compensation	—	(0.3)	10.1
Other items	0.1	(0.7)	2.8
Effective rate	0.3%	(1.4)%	(2.9)%

Significant components of the deferred tax assets and liabilities were as follows:

	December 31,	
	2008	2007
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 2,767	$ 2,449
Unit-based compensation	5,617	3,762
Other	897	285
Valuation allowance	(7,132)	(4,249)
Total deferred tax assets	2,149	2,247
Deferred tax liabilities:		
Property and equipment principally due to differences in depreciation	(2,149)	(2,247)
Total deferred tax liabilities	(2,149)	(2,247)
Net deferred tax assets (liabilities)	$ —	$ —

Net deferred tax assets and liabilities were classified in the consolidated balance sheets as follows:

	December 31,	
	2008	2007
	(in thousands)	
Deferred tax asset	$ 2,149	$ 2,247
Deferred tax liability	(2,149)	(2,247)
Net deferred tax assets (liabilities)	$ —	$ —

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is not more likely than not that the Company will realize the benefits of these deductible differences at December 31, 2008; therefore, the Company has recorded a valuation allowance against the deferred tax asset.

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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. The Company had no material uncertain tax positions at December 31, 2008 or 2007.

(17) Related Party Transactions

Lehman Holdings

During the year ended December 31, 2008 (through July 3, 2008), and the year ended December 31, 2007, on an aggregate basis, a group of certain direct or indirect wholly owned subsidiaries of Lehman Holdings owned over 10% of the Company’s outstanding units. As such, Lehman Holdings was considered a related party under the provisions of SFAS No. 57 “Related Party Disclosures” during that time frame. Lehman Holdings’ subsidiaries provided certain services to the Company, including participation in the Company’s Credit Facility, Term Loan, offering of Senior Notes (see Note 8), sale of Appalachian Basin assets (see Note 2) and sale of commodity derivative instruments (see Note 9), which were all consummated on terms equivalent to those that prevail in arm’s-length transactions. A reference to “Lehman” hereafter in this footnote refers to Lehman Holdings or one or more of its subsidiaries, as applicable. See Note 13 for details about Lehman’s Chapter 11 filings.

During the year ended December 31, 2008 (through July 3), the Company paid Lehman interest on borrowings of approximately $2.2 million and financing fees of approximately $1.8 million. During the years ended December 31, 2007, the Company paid Lehman interest on borrowings of approximately $2.1 million and financing fees of approximately $0.1 million.

During the year ended December 31, 2007, in conjunction with its private placements of units, the Company paid Lehman underwriting fees of approximately $13.5 million. Lehman was a participant in the private placements and the Company received approximately $378.7 million of proceeds from Lehman in relation to these transactions during the year ended December 31, 2007.

During the year ended December 31, 2008 (through July 3), the Company paid distributions on units to Lehman of approximately $18.5 million. During the year ended December 31, 2007, the Company paid distributions on units to Lehman of approximately $15.2 million. During the year ended December 31, 2008 (through July 3), the Company paid Lehman approximately $18.8 million, on settled commodity derivative contracts. During the year ended December 31, 2007, Lehman paid the Company approximately $8.2 million on settled commodity derivative contracts. During year ended December 31, 2008 (through July 3), the Company purchased approximately $1.3 million of deal contingent oil swap contracts from Lehman. In addition, during the year ended December 31, 2007, the Company paid Lehman approximately $226.3 million for oil and gas swap contracts.

The following sets forth the amounts due to or from Lehman as of December 31, 2007 (in thousands):

Assets:		
Current oil and gas derivative assets	$	14,226
Liabilities:		
Other accrued liabilities	$	1,440

Long-term debt	$	40,404
Noncurrent oil and gas derivative liabilities	$	7,028

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Other

Eric P. Linn, brother of the Company's Chairman and Chief Executive Officer, served as President of one of the Company's wholly owned subsidiaries. Effective March 31, 2008, Mr. Linn's employment with the Company terminated and he executed a Severance Agreement and Release. Under the terms of that agreement, Mr. Linn will receive $0.2 million in cash, six months of outplacement services, accelerated vesting of certain unvested restricted units and unvested options, and payment of COBRA coverage until December 31, 2008 or until obtainment of other comparable health care benefits.

During the years ended December 31, 2008 and 2007, the Company made payments of approximately $0.3 million and $0.2 million to a company owned by a member of its Board of Directors. The payments primarily reflect purchases of gas and are primarily included in "gas marketing expenses" on the consolidated statements of operations. The expenses were consummated on terms equivalent to those that prevail in arm's-length transactions.

During the year ended December 31, 2006, the Company made payments of approximately $0.4 million 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 consolidated statement of operations. The fees and expenses associated with the reimbursements were consummated on terms equivalent to those that prevail in arm's-length transactions. During the year ended December 31, 2006, the Company made other arrangements for corporate travel and these reimbursements were discontinued.

(18) Supplemental Disclosures to the Consolidated Balance Sheet and Consolidated Statement of Cash Flows

"Other accrued liabilities" reported on the consolidated balance sheet include the following:

	December 31, 2008	December 31, 2007
	(in thousands)	
Accrued compensation	$ 11,366	$ 6,498
Accrued interest	14,232	5,802
Other	1,565	2,130
	$ 27,163	$ 14,430

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Supplemental disclosures to the consolidated statement of cash flows are presented below:

	Year Ended December 31, 2008	2007 (in thousands)	2006
Cash payments for interest	$ 94,958	$ 57,348	$ 24,147
Cash payments for income taxes	$ 452	$	$
Non-cash investing activities:			
In connection with the purchase of oil and gas properties, liabilities were assumed as follows:			
Fair value of assets acquired	$ 602,858	$ 2,710,417	$ 470,362
Cash paid	(593,412)	(2,649,965)	(467,137)
Liabilities assumed, net	$ 9,446	$ 60,452	$ 3,225
Non-cash financing activities:			
Units issued in connection with the purchase of oil and gas properties	$ 23,455	$	$

(19) Recently Issued Accounting Standards

In October 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") FAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active" ("FSP 157-3"), which clarifies the application of SFAS 157 in a market that is not active. FSP 157-3 is effective upon issuance and its adoption had no material impact on the Company's results of operations or financial position.

In June 2008, the FASB issued FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities," which addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008. The Company is currently evaluating the impact the provisions of this FSP will have on its results of operations and financial position, but does not expect it will be material.

In April 2008, the FASB issued FSP FAS 142-3, "Determination of the Useful Life of Intangible Assets," which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of the asset. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008. The Company is currently evaluating the impact the provisions of this FSP will have on its results of operations and financial position, but does not expect it will be material.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities - an Amendment of FASB Statement 133" ("SFAS 161"). SFAS 161 requires expanded disclosure regarding derivatives and hedging activities including disclosure of the fair values of derivative instruments and their gains and losses in tabular form. SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008, with early adoption encouraged. The Company adopted SFAS 161 effective January 1, 2008 (see Note 9). The adoption of the requirements of SFAS 161, which solely expanded disclosures, had no effect on the Company's results of operations or financial position.

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In February 2008, the FASB issued FSP FAS 157-2, "Effective Date of FASB Statement No. 157," which defers the effective date of SFAS 157 for one year for certain nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. On January 1, 2008, the Company adopted the provisions of SFAS 157 related to financial assets and liabilities and to nonfinancial assets and liabilities measured at fair value on a recurring basis (see Note 10). On January 1, 2009, the Company will adopt the provisions for nonfinancial assets and nonfinancial liabilities that are not required or permitted to be measured at fair value on a recurring basis, which include those measured at fair value in goodwill impairment testing, indefinite-lived intangible assets measured at fair value for impairment assessment, nonfinancial long-lived assets measured at fair value for impairment assessment, asset retirement obligations initially measured at fair value, and those initially measured at fair value in a business combination. The Company is currently evaluating the impact the provisions of SFAS 157 related to these items will have on its results of operations and financial position.

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), "Business Combinations" ("SFAS 141R"). Under Statement 141R, an acquiring entity will be required to recognize all the assets acquired and liabilities assumed at the acquisition date fair value with limited exceptions. Statement 141R will change the accounting treatment for certain specific items, including acquisition costs, which will be expensed as incurred, and acquired contingent liabilities, which will be recorded at fair value at the acquisition date. SFAS 141R also includes new disclosure requirements. SFAS 141R applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period on or after December 15, 2008, with earlier adoption prohibited. The Company will implement SFAS 141R as related to acquisitions that occur after January 1, 2009.

In September 2006, the FASB issued 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 Company adopted the provisions of SFAS 157 for financial assets effective January 1, 2008 (see Note 10). The provisions of SFAS 157 are applicable to non-financial assets effective for fiscal years beginning after November 15, 2008. The Company is currently evaluating the impact the adoption of SFAS 157 for non-financial assets will have on its results of operations and financial position.

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LINN ENERGY, LLC
SUPPLEMENTAL OIL AND GAS DATA (Unaudited)

The following discussion and analysis should be read in conjunction with the "Selected Historical Consolidated Financial and Operating Data" and the financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The Company's Appalachian Basin and Mid Atlantic operations have been classified as discontinued operations on the consolidated statement of operations for all periods presented (see Note 2). Unless otherwise indicated, information presented in the following supplemental oil and gas data has been recast to present continuing operations separately from discontinued operations.

(A) Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

Costs incurred in oil and gas property acquisition and development, whether capitalized or expensed, are presented below (balances include amounts associated with oil and gas properties for which results are reported in discontinued operations):

	Year Ended December 31, 2008	2007	2006
		(in thousands)	
Property acquisition costs:			
Proved	$ 595,795	$ 2,422,983	$ 450,232
Unproved	4,111	148,284	4,062
Development costs	332,557	189,466	47,112
Total costs incurred	$ 932,463	$ 2,760,733	$ 501,406

Costs incurred during the year ended December 31, 2008 include approximately $900.3 million ($314.9 million excluding acquisition and asset retirement obligation costs) of costs from continuing operations and $32.2 million ($15.7 million excluding acquisition and asset retirement obligation costs) of costs from discontinued operations. Costs incurred during the year ended December 31, 2007 include approximately $2.67 billion ($144.8 million excluding acquisition and asset retirement obligation costs) of costs from continuing operations and $86.3 million ($40.7 million excluding acquisition and asset retirement obligation costs) of costs from discontinued operations. Costs incurred during the year ended December 31, 2006 include approximately $417.7 million ($4.2 million excluding acquisition and asset retirement obligation costs) of costs from continuing operations and $83.7 million ($42.8 million excluding acquisition and asset retirement obligation costs) of costs from discontinued operations.

(B) Oil and Gas Capitalized Costs

Aggregate capitalized costs related to oil and gas production activities with applicable accumulated depletion and amortization are presented below (balances include amounts associated with oil and gas properties for which results are reported in discontinued operations):

	December 31, 2008	2007
	(in thousands)	
Proved properties:		
Leasehold acquisition	$ 3,278,155	$ 3,095,400
Development	460,730	254,251
Unproved properties	92,298	156,908
	3,831,183	3,506,559

Less accumulated depletion and amortization		(278,805)		(120,498)
Net capitalized costs	$	3,552,378	$	3,386,061

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(C) Results of Oil and Gas Producing Activities

The results of operations for oil and gas producing activities (excluding corporate overhead and interest costs) are presented below:

	Year Ended December 31, 2008	2007	2006
		(in thousands)	
Revenues and other:			
Oil, gas and natural gas liquid sales	$ 755,644	$ 255,927	$ 21,372
Gain (loss) on oil and gas derivatives	662,782	(345,537)	103,308
	1,418,426	(89,610)	124,680
Production costs:			
Lease operating expenses	115,402	41,946	6,603
Transportation expenses	17,597	5,575	40
Production and ad valorem taxes	59,598	20,295	229
	192,597	67,816	6,872
Other costs:			
Exploration costs	7,603	4,053	286
Depletion and amortization	185,857	64,857	4,018
Impairment of goodwill and long-lived assets	50,505		
Texas margin tax expense	920		
(Gain) loss on sale of assets, net	(99,050)		
	145,835	68,910	4,304
Results of continuing operations	$ 1,079,994	$ (226,336)	$ 113,504
Results of discontinued operations	$ 190,915	$ 19,111	$ 30,475

There is no federal tax provision included in the results of oil and gas producing activities because the Company's subsidiaries subject to federal tax do not own any of the Company's oil and gas interests. Limited liability companies are subject to state income taxes in Texas (see Note 16).

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(D) Net Proved Oil and Gas Reserves

The proved reserves of oil and gas of the Company have been prepared by the independent engineering firm DeGolyer and MacNaughton at December 31, 2008, 2007 and 2006. These reserve estimates have been prepared in compliance with the SEC rules based on year-end prices. An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the United States, is shown below:

Year Ended December 31, 2008

	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total Continuing Operations (MMcfe)	Total Discontinued Operations (MMcfe)	Total (MMcfe)
Proved developed and undeveloped reserves:						
Beginning of year	833,390	54,469	43,124	1,418,947	197,160	1,616,107
Revisions of previous estimates	(122,138)	(16,223)	(1,427)	(228,036)	—	(228,036)
Purchase of minerals in place	72,817	46,099	3,121	368,136	5,340	373,476
Sales of minerals in place	(47,467)	(270)	(11)	(49,154)	(199,711)	(248,865)
Extensions, discoveries and other additions	159,836	3,207	8,167	228,083	1,757	229,840
Production	(45,206)	(3,138)	(2,252)	(77,548)	(4,546)	(82,094)
End of year	851,232	84,144	50,722	1,660,428	—	1,660,428
Proved developed reserves:						
Beginning of year	616,109	42,509	25,546	1,024,440	147,702	1,172,142
End of year	585,071	61,884	29,600	1,133,976	—	1,133,976

Year Ended December 31, 2007

	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total Continuing Operations (MMcfe)	Total Discontinued Operations (MMcfe)	Total (MMcfe)
Proved developed and undeveloped reserves:						
Beginning of year	77,275	29,639	—	255,109	198,957	454,066
Revisions of previous estimates	(7,375)	6,555	162	32,923	(18,392)	14,531
Purchase of minerals in place	714,026	17,823	41,741	1,071,409	23,558	1,094,967
Sales of minerals in place	—	—	—	—	(1,511)	(1,511)
Extensions, discoveries and other additions	67,994	1,694	2,213	91,437	3,196	94,633
Production	(18,530)	(1,242)	(992)	(31,931)	(8,648)	(40,579)
End of year	833,390	54,469	43,124	1,418,947	197,160	1,616,107

Proved developed reserves:						
Beginning of year	49,383	24,304	—	195,206	118,851	314,057
End of year	616,109	42,509	25,546	1,024,440	147,702	1,172,142

	Year Ended December 31, 2006				
	Gas (MMcf)	Oil (MBbls)	Total Continuing Operations (MMcfe)	Total Discontinued Operations (MMcfe)	Total (MMcfe)
Proved developed and undeveloped reserves:					
Beginning of year				193,210	193,210
Revisions of previous estimates	(6,929)	196	(5,754)	(29,264)	(35,018)
Purchase of minerals in place	84,951	29,784	263,655		263,655
Extensions, discoveries and other additions				43,037	43,037
Production	(747)	(341)	(2,792)	(8,026)	(10,818)
End of year	77,275	29,639	255,109	198,957	454,066
Proved developed reserves:					
Beginning of year			—	125,220	125,220
End of year	49,383	24,304	195,206	118,851	314,057

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The tables above include changes in estimated quantities of oil and NGL reserves shown in Mcf equivalents at a rate of one barrel per six Mcf.

The Company sold its interests in oil and gas properties located in the Appalachian Basin during the year ended December 31, 2008 and the "total discontinued operations" column in the tables above reports the information for these properties. Other property sales during the year ended December 31, 2008 include the sale of assets in the Verden area of Oklahoma. See Note 2 for additional details.

Substantially all of the 228,036 MMcfe negative revision of previous estimates during the year ended December 31, 2008 was due to decreases in oil and gas prices. The 14,531 MMcfe positive revision of previous estimates during the year ended December 31, 2007 was due to a combination of reasons including higher oil and gas prices, partially offset by higher operating costs, asset performance and changes to future scheduled capital projects. The 35,018 MMcfe negative revision of previous estimate during the year ended December 31, 2006 was due primarily to a decrease in gas prices.

The Company made four, eight and five acquisitions of working and royalty interests during the years ended December 31, 2008, 2007 and 2006, respectively, with total proved reserves of 373,476 MMcfe, 1,094,967 MMcfe and 263,655 MMcfe, respectively. See Note 3 for additional details.

Extensions and discoveries of 229,840 MMcfe, 94,633 MMcfe and 43,037 MMcfe during the years ended December 31, 2008, 2007 and 2006, respectively, were primarily due to the drilling of 351 wells during 2008, 253 wells during 2007 and 159 wells during 2006, which increased the Company's proved reserves.

(E) Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Reserves

Information with respect to the standardized measure of discounted future net cash flows relating to proved reserves is summarized below. Future cash inflows are computed by applying year-end prices relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. There are no future income tax expenses because the Company is not subject to federal income taxes. Limited liability companies are subject to state income taxes in Texas; however, these amounts are not material (see Note 16).

	December 31, 2008	2007	2006
		(in thousands)	
Future estimated revenues	$ 8,261,234	$ 12,565,382	$ 1,814,226
Future estimated production costs	(3,410,684)	(3,052,847)	(538,968)
Future estimated development costs	(896,625)	(582,890)	(92,904)
Future net cash flows	3,953,925	8,929,645	1,182,354
10% annual discount for estimated timing of cash flows	(2,529,558)	(5,754,798)	(883,594)
Standardized measure of discounted future net cash flows – continuing operations	$ 1,424,367	$ 3,174,847	$ 298,760
Standardized measure of discounted future net cash flows – discontinued operations	$ —	$ 283,392	$ 253,500
Representative NYMEX oil and gas prices at period end:			
Gas (MMBtu)	$ 5.71	$ 6.80	$ 5.64
Oil (Bbl)	$ 39.22	$ 95.92	$ 61.05

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The following summarizes the principal sources of change in the standardized measure of discounted future net cash flows:

	Year Ended December 31, 2008	2007 (in thousands)	2006
Sales of oil and gas production, net of production costs	$ (563,047)	$ (188,111)	$ (14,500)
Changes in estimated future development costs	32,006	6,271	(521)
Net changes in prices and production costs	(2,837,262)	81,654	
Purchase of minerals in place	1,066,615	2,438,178	508,107
Sale of minerals in place	(102,437)		
Extensions, discoveries, and improved recovery, less related costs	383,017	172,989	
Development costs incurred during the period	76,150	69,221	47,112
Revisions of previous quantity estimates	(69,044)	56,154	
Change in discount	317,485	29,876	
Changes in production rates and other	(53,963)	209,855	(241,438)
Change – continuing operations	$ (1,750,480)	$ 2,876,087	$ 298,760
Change – discontinued operations	$ (283,392)	$ 29,892	$ (298,575)

The data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

(F) Recent SEC Rule-Making Activity

In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserve reporting requirements. The most significant amendments to the requirements include the following:

- commodity prices – economic producibility of reserves and discounted cash flows will be based on a 12-month average commodity price unless contractual arrangements designate the price to be used;
- disclosure of unproved reserves – probable and possible reserves may be disclosed separately on a voluntary basis;
- proved undeveloped reserve guidelines – reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered;
- reserve estimation using new technologies – reserves may be estimated through the use of reliable technology in addition to flow tests and production history; and
- non-traditional resources – the definition of oil and gas producing activities will expand and focus on the marketable product rather than the method of extraction.

The rules are effective for fiscal years ending on or after December 31, 2009, and early adoption is not permitted. The Company is currently evaluating the new rules and assessing the impact they will have its reported oil and gas reserves. The SEC is coordinating with the FASB to obtain the revisions necessary to SFAS No. 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies,” and SFAS No. 69, “Disclosures about Oil and Gas Producing Activities” to provide consistency with the new rules. In the event that consistency is not achieved in time for companies to comply with the new rules, the SEC will consider delaying the compliance date.

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LINN ENERGY, LLC
SUPPLEMENTAL QUARTERLY DATA (Unaudited)

The following discussion and analysis should be read in conjunction with the "Selected Historical Consolidated Financial and Operating Data" and the financial statements and related notes included elsewhere in this Annual Report on Form 10-K.

(A) Quarterly Financial Data

	Quarters Ended March 31	June 30	September 30	December 31
	(in thousands, except per unit amounts)			
2008				
Oil, gas and natural gas liquid sales (1)	$ 175,872	$ 255,586	$ 240,634	$ 83,552
Gain (loss) on oil and gas derivatives	$ (268,794)	$ (870,804)	$ 845,818	$ 956,562
Total revenues and other	$ (89,627)	$ (610,983)	$ 1,091,660	$ 1,043,981
Total expenses (2)	$ 104,274	$ 118,521	$ 132,889	$ 180,848
(Gain) loss on sale of assets, net	$	$	$	$ (98,763)
Income (loss) from continuing operations	$ (258,959)	$ (725,381)	$ 921,943	$ 888,054
Income (loss) from discontinued operations, net of taxes (3)	$ (400)	$ 13,239	$ 160,668	$ 452
Net income (loss)	$ (259,359)	$ (712,142)	$ 1,082,611	$ 888,506
Income (loss) per unit – continuing operations:				
Basic	$ (2.28)	$ (6.35)	$ 8.06	$ 7.77
Diluted	$ (2.28)	$ (6.35)	$ 8.05	$ 7.76
Income per unit – discontinued operations:				
Basic	$	$ 0.12	$ 1.41	$ 0.01
Diluted	$	$ 0.12	$ 1.41	$
Net income (loss) per unit:				
Basic	$ (2.28)	$ (6.23)	$ 9.47	$ 7.78
Diluted	$ (2.28)	$ (6.23)	$ 9.46	$ 7.76

(1) Oil, gas and natural gas liquid sales decreased during the quarter ended December 31, 2008 primarily due to lower commodity prices. In addition, non-operated accrual estimate revisions associated with prior quarters of approximately $14.1 million contributed to the decrease.

(2) Includes the following expenses: lease operating, transportation, gas marketing, general and administrative, exploration, bad debt, depreciation, depletion and amortization, impairment of goodwill and long-lived assets, and taxes, other than income taxes.

(3) Includes discontinued operations' gain (loss) on sale of assets, net of taxes.

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	Quarters Ended March 31	June 30	September 30	December 31
	(in thousands, except per unit amounts)			
2007				
Oil, gas and natural gas liquid sales	$ 23,567	$ 32,495	$ 61,318	$ 138,547
Loss on oil and gas derivatives	$ (60,441)	$ (17,707)	$ (65,440)	$ (201,949)
Total revenues and other	$ (34,308)	$ 18,015	$ (203)	$ (58,787)
Total expenses (1)	$ 25,558	$ 30,689	$ 54,172	$ 93,060
(Gain) loss on sale of assets, net	$	$	$ 67	$ 1,700
Loss from continuing operations	$ (68,421)	$ (17,064)	$ (71,831)	$ (198,878)
Income (loss) from discontinued operations, net of taxes (2)	$ 574	$ (62)	$ (4,391)	$ (4,276)
Net loss	$ (67,847)	$ (17,126)	$ (76,222)	$ (203,154)
Loss per unit – continuing operations:				
Basic	$ (1.36)	$ (0.29)	$ (0.89)	$ (1.97)
Diluted	$ (1.36)	$ (0.29)	$ (0.89)	$ (1.97)
Income (loss) per unit – discontinued operations:				
Basic	$ 0.01	$	$ (0.05)	$ (0.04)
Diluted	$ 0.01	$	$ (0.05)	$ (0.04)
Net loss per unit:				
Basic	$ (1.35)	$ (0.29)	$ (0.94)	$ (2.01)
Diluted	$ (1.35)	$ (0.29)	$ (0.94)	$ (2.01)

(1) Includes the following expenses: lease operating, transportation, gas marketing, general and administrative, exploration, depreciation, depletion and amortization and taxes, other than income taxes.

(2) Includes discontinued operations' gain (loss) on sale of assets, net of taxes.

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Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

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

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. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2008.

Management's Annual Report on Internal Control Over Financial Reporting

See Management's Report on Internal Control Over Financial Reporting under Item 8 of this Form 10-K.

Changes in the Company's Internal Control Over Financial Reporting

The Company's management is also responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. The Company's internal controls were designed to provide reasonable assurance as to the reliability of its financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

There were no changes in the Company's internal controls over financial reporting during the fourth quarter of 2008 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

None.

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

A list of the Company's executive officers and biographical information appears in Part I. Item 1. "Business" in this Form 10-K. Information about Company Directors may be found under the caption "Election of Directors" of the Proxy Statement for the Annual Meeting of Unitholders to be held on May 5, 2009 (the "2009 Proxy Statement"). That information is incorporated herein by reference.

The information in the 2009 Proxy Statement set forth under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" is incorporated herein by reference.

The information required by this item regarding audit committee related matters, codes of ethics and committee charters is incorporated by reference from the 2009 Proxy Statement under the caption "Corporate Governance."

Item 11. Executive Compensation

Information required by this item is incorporated herein by reference to the 2009 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item is incorporated herein by reference to the 2009 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following summarizes information regarding the number of units that are available for issuance under all of the Company's equity compensation plans as of December 31, 2008:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Unit Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Unit Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders	1,590,438	$ 24.04	8,278,115
Equity compensation plans not approved by security holders			
Total	1,590,438	$ 24.04	8,278,115

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is incorporated herein by reference to the 2009 Proxy Statement.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated herein by reference to the 2009 Proxy Statement.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) – 2. Financial Statement Schedules:

All schedules are omitted for the reason that they are not required or the information is otherwise supplied under Part II. Item 8. “Financial Statements and Supplementary Data.”

(a) – 3. Exhibits Filed:

The exhibits required to be filed by this Item 15 are set forth in the Index to Exhibits accompanying this report.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

LINN ENERGY, LLC

Date: February 26, 2009	By:	/s/ Michael C. Linn Michael C. Linn Chairman and Chief Executive Officer
Date: February 26, 2009	By:	/s/ David B. Rottino David B. Rottino Senior Vice President and Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Michael C. Linn Michael C. Linn	Chairman and Chief Executive Officer (Principal Executive Officer)	February 26, 2009
/s/ Kolja Rockov Kolja Rockov	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2009
/s/ David B. Rottino David B. Rottino	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 26, 2009
/s/ George A. Alcorn George A. Alcorn	Independent Director	February 26, 2009
/s/ Terrence S. Jacobs Terrence S. Jacobs	Independent Director	February 26, 2009
/s/ Joseph P. McCoy Joseph P. McCoy	Independent Director	February 26, 2009
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Independent Director	February 26, 2009

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INDEX TO EXHIBITS

Exhibit Number		Description
2.1*	—	Limited Partnership Asset Purchase and Sale Agreement, dated as of April 13, 2008, between Linn Energy Holdings, LLC, Marathon 85-II Limited Partnership and Marathon 85-III Limited Partnership, as sellers, and XTO Energy, Inc., as buyer (incorporated herein by reference to Exhibit 2.2 to Quarterly Report on Form 10-Q filed on May 8, 2008)
2.2*	—	First Amendment, dated as of July 1, 2008, to Limited Partnership Asset Purchase and Sale Agreement between Linn Energy Holdings, LLC, Marathon 85-II Limited Partnership, Marathon 85-III Limited Partnership, as sellers and XTO Energy Inc., as buyer (incorporated herein by reference to Exhibit 2.3 to Quarterly Report on Form 10-Q filed on August 7, 2008)
2.3*	—	Asset Purchase and Sale Agreement, dated October 9, 2008, between Linn Energy Holdings, LLC, Mid-Continent I, LLC, Mid-Continent II, LLC, Linn Operating, Inc. and Devon Energy Production Company, LP (incorporated herein by reference to Exhibit 2.1 to Quarterly Report on Form 10-Q filed on November 6, 2008)
2.4*†	—	First Amendment, dated as of December 4, 2008, to Asset Purchase and Sale Agreement, dated October 9, 2008, between Linn Energy Holdings, LLC, Mid-Continent I, LLC, Mid-Continent II, LLC, Linn Operating, Inc. and Devon Energy Production Company, LP
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 Registration Statement on Form S-1 (File No. 333-125501) filed by Linn Energy, LLC 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 for the year ended December 31, 2006, 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 3.4 to Annual Report on Form 10-K for the year ended December 31, 2006, 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 3.5 to Annual Report on Form 10-K for the year ended December 31, 2006, 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 the Annual Report on Form 10-K for the year ended December 31, 2005, filed on May 31, 2006)
4.2	—	Indenture, dated as of June 27, 2008, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on June 30, 2008)
4.3	—	Registration Rights Agreement, dated June 27, 2008, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and the representatives of the Initial Purchasers named therein (incorporated herein by reference to Exhibit 4.2 to Current Report on Form 8-K filed on June 30, 2008)
10.1**	—	Linn Energy, LLC Amended and Restated Long-Term Incentive Plan (incorporated herein by reference to Annex A to the Proxy Statement for 2008 Annual Meeting, filed on April 21, 2008)

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Exhibit Number		Description
10.2**†	—	Amendment No. 1 to Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, dated February 4, 2009
10.3**†	—	Form of Executive Unit Option Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended
10.4**†	—	Form of Executive Restricted Unit Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended
10.5**	—	Form of Phantom Unit Grant Agreement for Independent Directors pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (incorporated herein by reference to Exhibit 10.1 to Current Report on Form 8-K filed on August 9, 2006)
10.6**†	—	Form of Director Restricted Unit Grant Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended
10.7**†	—	Third Amended and Restated Employment Agreement, dated effective as of December 17, 2008 between Linn Operating, Inc. and Michael C. Linn
10.8**†	—	Third Amended and Restated Employment Agreement, dated effective as of December 17, 2008 between Linn Operating, Inc. and Kolja Rockov
10.9**†	—	Amended and Restated Employment Agreement, dated effective as of December 17, 2008 between Linn Operating, Inc. and Mark E. Ellis
10.10**†	—	Amended and Restated Employment Agreement, dated effective December 17, 2008 between Linn Operating, Inc. and Charlene A. Ripley
10.11**†	—	Amended and Restated Employment Agreement, dated effective December 17, 2008 between Linn Operating, Inc. and Arden L. Walker, Jr.
10.12**†	—	Second Amended and Restated Employment Agreement, dated December 17, 2008 between Linn Operating, Inc. and David B. Rottino
10.13**	—	Separation Agreement, dated effective June 11, 2008 between Linn Operating, Inc. and Lisa D. Anderson (incorporated herein by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q filed on August 7, 2008)
10.14**	—	Separation Agreement, dated effective May 8, 2008 between Linn Operating, Inc. and Thomas A. Lopus (incorporated herein by reference to Exhibit 10.4 to Quarterly Report on Form 10-Q filed on August 7, 2008)
10.15**†	—	Indemnity Agreement, dated as of February 4, 2009 between Linn Energy, LLC and George A. Alcorn
10.16**†	—	Indemnity Agreement, dated as of February 4, 2009 between Linn Energy, LLC and Joseph P. McCoy
10.17**†	—	Indemnity Agreement, dated as of February 4, 2009 between Linn Energy, LLC and Terrence S. Jacobs
10.18**†	—	Indemnity Agreement, dated as of February 4, 2009 between Linn Energy, LLC and Jeffrey C. Swoveland

10.19**†	—	Indemnity Agreement, dated as of February 4, 2009 between Linn Energy, LLC and Michael C. Linn
10.20**†	—	Indemnity Agreement, dated as of February 4, 2009 between Linn Energy, LLC and Mark E. Ellis
10.21**†	—	Indemnity Agreement, dated as of February 4, 2009 between Linn Energy, LLC and Kolja Rockov
10.22**†	—	Indemnity Agreement, dated as of February 4, 2009 between Linn Energy, LLC and Charlene A. Ripley
10.23**†	—	Indemnity Agreement, dated as of February 4, 2009 between Linn Energy, LLC and David B. Rottino
10.24**†	—	Indemnity Agreement, dated as of February 4, 2009 between Linn Energy, LLC and Arden L. Walker, Jr.
10.25	—	Third Amended and Restated Credit Agreement dated as of August 31, 2007 among Linn Energy, LLC as Borrower, BNP Paribas, as Administrative Agent, and the Lenders and agents Party thereto (incorporated herein by reference to Exhibit 10.1 to Current Report on Form 8-K filed on September 5, 2007)

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Exhibit Number		Description
10.26	—	First Amendment, dated November 2, 2007, to Third Amended and Restated Credit Agreement among Linn Energy, LLC, as borrower, BNP Paribas, as administrative agent, and the lenders and agents party thereto (incorporated herein by reference to Exhibit 10.15 to Annual Report on Form 10-K for the year ended December 31, 2007, filed on February 29, 2008)
10.27	—	Second Amendment, dated January 31, 2008, to Third Amended and Restated Credit Agreement among Linn Energy, LLC, as borrower, BNP Paribas, as administrative agent, and the lenders and agents party thereto (incorporated herein by reference to Exhibit 10.16 to Annual Report on Form 10-K for the year ended December 31, 2007, filed on February 29, 2008)
10.28	—	Third Amendment, dated as of June 16, 2008, to Third Amended and Restated Credit Agreement among Linn Energy, LLC, as Borrower, BNP Paribas, as Administrative Agent and the lenders and agents party thereto (incorporated herein by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed on August 7, 2008)
10.29	—	Fourth Amendment, dated effective August 20, 2008, to Third Amended and Restated Credit Agreement among Linn Energy, LLC, as Borrower, BNP Paribas, as Administrative Agent, and the lenders and agents party thereto (incorporated herein by reference to Exhibit 10.1 to Current Report on Form 8-K filed on August 26, 2008)
10.30	—	Third Amended and Restated Guaranty and Pledge Agreement, dated as of August 31, 2007, made by Linn Energy, LLC and each of the other Obligors in favor of BNP Paribas, as Administrative Agent (incorporated herein by reference to Exhibit 10.2 to Current Report on Form 8-K filed on September 5, 2007)
21.1†	—	Significant Subsidiaries of Linn Energy, LLC
23.1†	—	Consent of KPMG LLP for Linn Energy, LLC
23.2†	—	Consent of DeGolyer and MacNaughton Data and Consulting Services
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.

* The schedules to this agreement have been omitted from this filing pursuant to Item 601(b)(2) of Regulation S-K. The Company will furnish copies of such schedules to the Securities and Exchange Commission upon request.

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