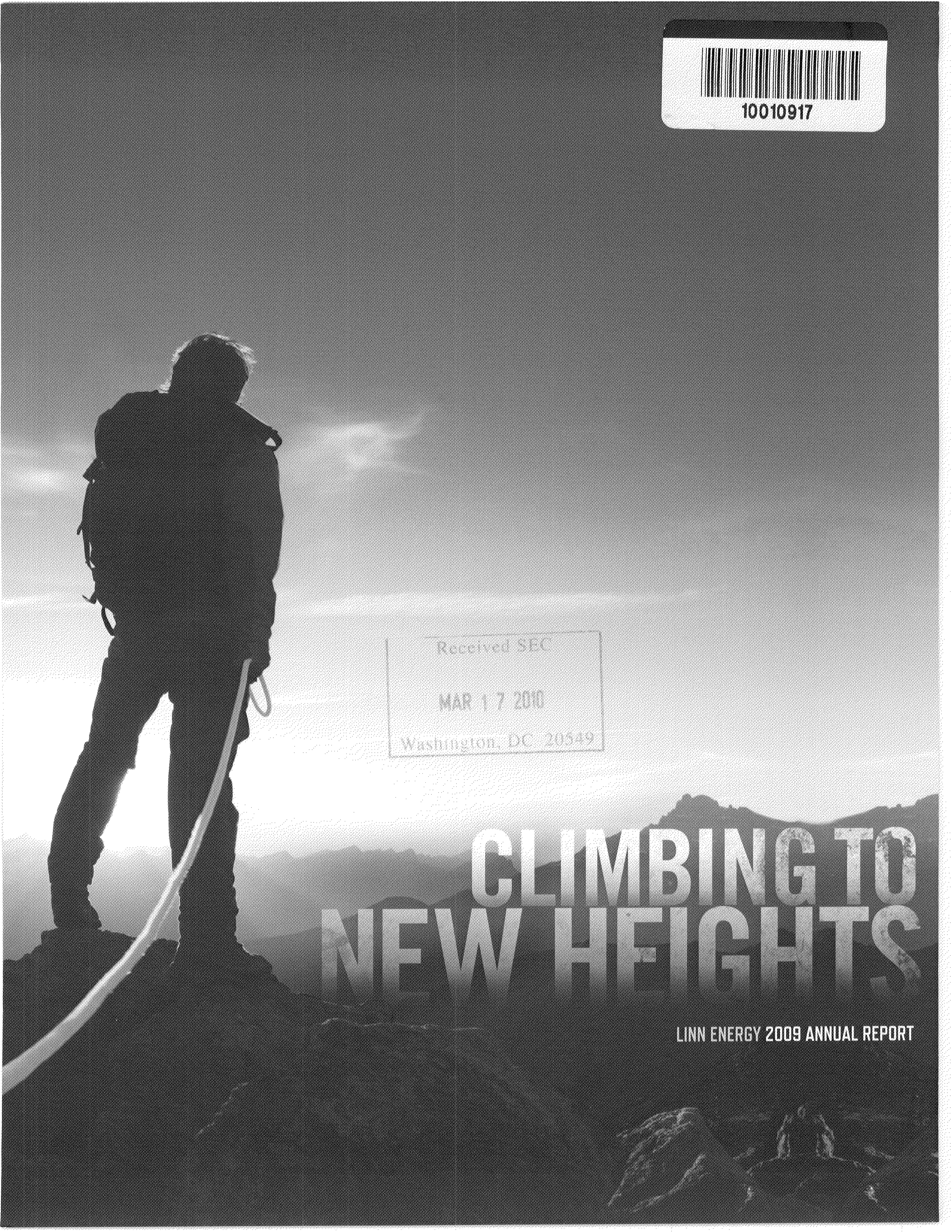


CLIMBING TO NEW HEIGHTS

LINN ENERGY 2009 ANNUAL REPORT

FINANCIAL HIGHLIGHTS

YEAR ENDED DECEMBER 31	2009	2008
(U.S dollars in thousands, except per unit amounts)		
Cash Distribution Paid per Unit	$ 2.52	$ 2.52
Adjusted EBITDA*	$ 566,235	$ 514,487
INCOME STATEMENT:		
Oil & Natural Gas Revenues	$ 408,219	$ 755,644
Net Income (Loss)	$ (295,841)	$ 825,657
Net Income (Loss) per Unit — Basic	$ (2.48)	$ 7.18
Adjusted Net Income**	$ 206,922	$ 174,663
Adjusted Net Income per Unit — Basic**	$ 1.73	$ 1.52
BALANCE SHEET:		
Total Assets	$ 4,340,256	$ 4,722,020
Total Long-Term Debt	$ 1,588,831	$ 1,653,568
Unitholders' Capital	$ 2,452,004	$ 2,760,686
Weighted Average Number of Units Outstanding — Basic (thousands)	119,307	114,140
AVERAGE DAILY PRODUCTION:		
Natural Gas (MMcf/d)	125	124
Total Liquids (MBbls/d)	16	15
Total (MMcfe/d)	218	212
ESTIMATED YEAR-END PROVED RESERVES:		
Natural Gas (Bcf)	774	851
Total Liquids (MMBbls)	156	135
Total (Bcfe)	1,712	1,660
Reserve-Replacement Ratio (Drillbit)***	112%	282%
Reserve-Replacement Ratio***	189%	756%

All amounts reported are from continuing operations.

* Adjusted EBITDA is a Non-GAAP financial measure. Please see "Reconciliation of Non-GAAP Measures" on page A-1 and also found within the Company's Annual Report on Form 10-K for the year ended December 31, 2009, on page 57.

** Adjusted Net Income and Adjusted Net Income per Unit are Non-GAAP financial measures. Please see "Reconciliation of Non-GAAP Measures" on page A-2 and also found within the Company's Annual Report on Form 10-K for the year ended December 31, 2009, on page 58.

*** Excludes price-related revisions. Please see "Reconciliation of Non-GAAP Measures" on page A-3 and also found within the Company's Annual Report on Form 10-K for the year ended December 31, 2009, on page 50.

GLOSSARY OF TERMS

Bbl One stock tank barrel or 42 United States gallons liquid volume.

Bcf One billion cubic feet.

Bcfe One billion cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of 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 degrees to 59.5 degrees Fahrenheit.

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 natural 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 natural gas to one Bbl of oil, condensate or natural gas liquids.

MMcfe/d MMcfe per day.

MMMBtu One billion British thermal units.

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

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

Total Unitholder Return Change in market price, adjusted for reinvested distributions.

OUR COMPANY

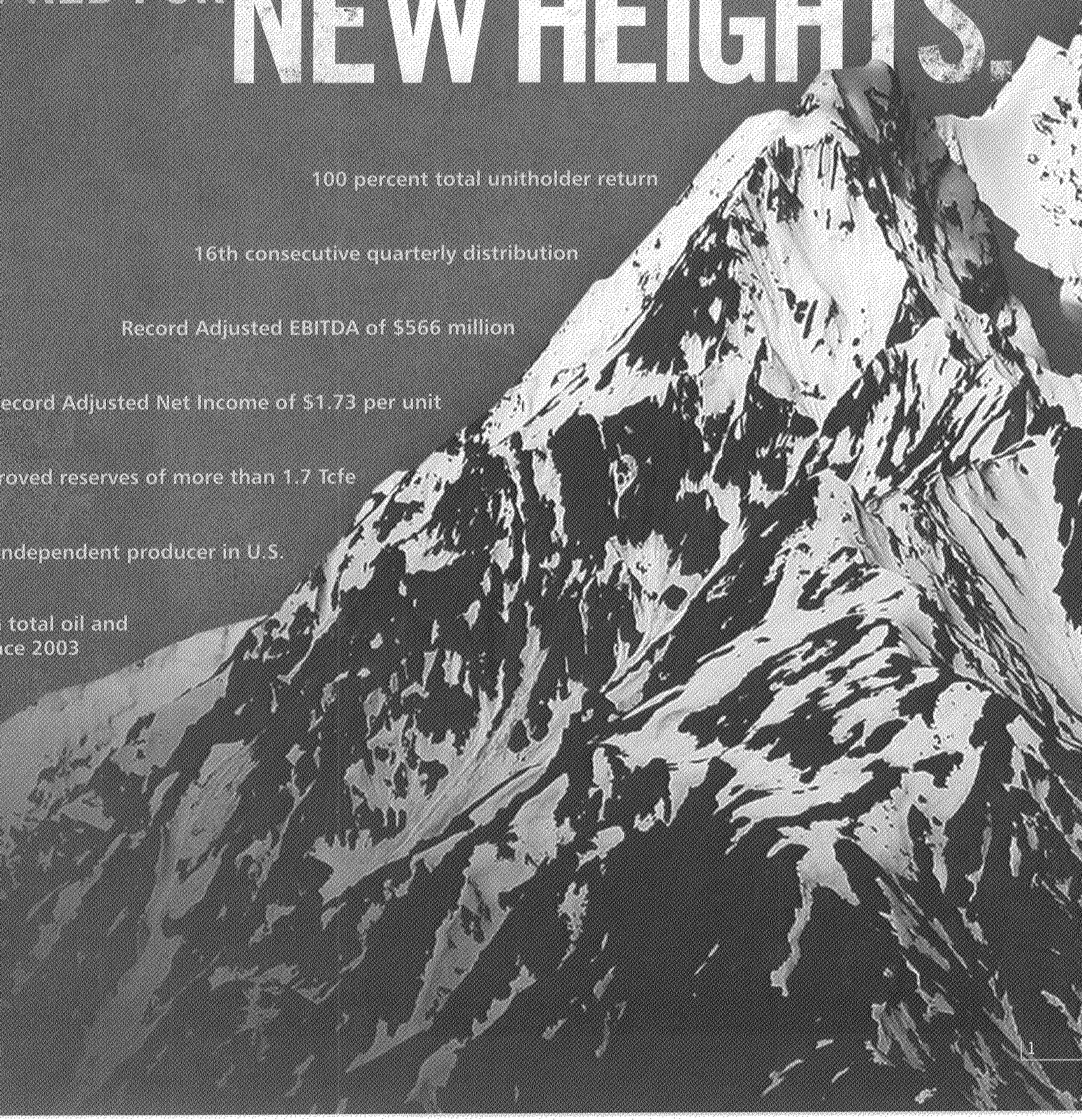
LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. LINN is an independent oil and natural gas development company that was founded in 2003 and became the first publicly traded independent oil and natural gas limited liability company in 2006. Its areas of operation are:

- Mid-Continent
- California
- Permian Basin

At year-end 2009, LINN had total proved reserves of more than 1.7 Tcfe. These reserves, which are 36 percent oil, 19 percent NGL and 45 percent natural gas, have a long proved reserve-life index of more than 20 years. In addition, the Company has more than 6,900 producing oil and natural gas wells and more than 4,200 drilling locations.

LINN Energy is focused on developing its reserve base and evaluating potential opportunities to acquire additional oil and natural gas properties that complement its asset profile in mature producing basins across the United States.

2009 PROVED WE ARE PREPARED FOR NEW HEIGHTS.



100 percent total unitholder return

16th consecutive quarterly distribution

Record Adjusted EBITDA of $566 million

Record Adjusted Net Income of $1.73 per unit

Proved reserves of more than 1.7 Tcfe

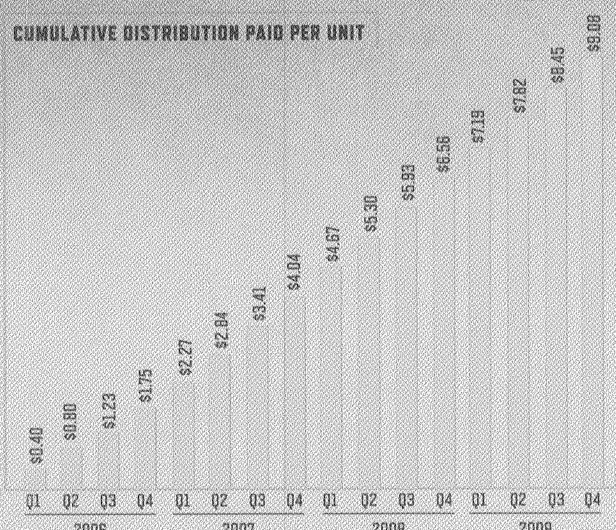
Top 25 independent producer in U.S.

More than $4.2 billion total oil and natural gas assets acquired since 2003

MESSAGE FROM MIKE LINN:

I founded LINN Energy in 2003 and, in just six years, the Company has climbed to new heights — growing from a handful of natural gas wells with a few employees in Appalachia into a publicly traded, multi-billion dollar company with more than 500 employees in offices across the country. Today, LINN Energy is headquartered in Houston and ranks among the 25 largest independent oil and natural gas companies in the United States.

Our success is directly attributable to our employees, and I would like to personally thank them for their hard work and dedication to our Company, investors and communities. The Company generated more than 100 percent return to our unitholders in 2009 and paid its 16th consecutive quarterly cash distribution in February 2010. On the community front, during 2009 LINN employees dedicated their personal energy and resources to numerous worthy causes in our key focus areas of community service, education, health and the arts. This performance and generosity is impressive in any economic environment.

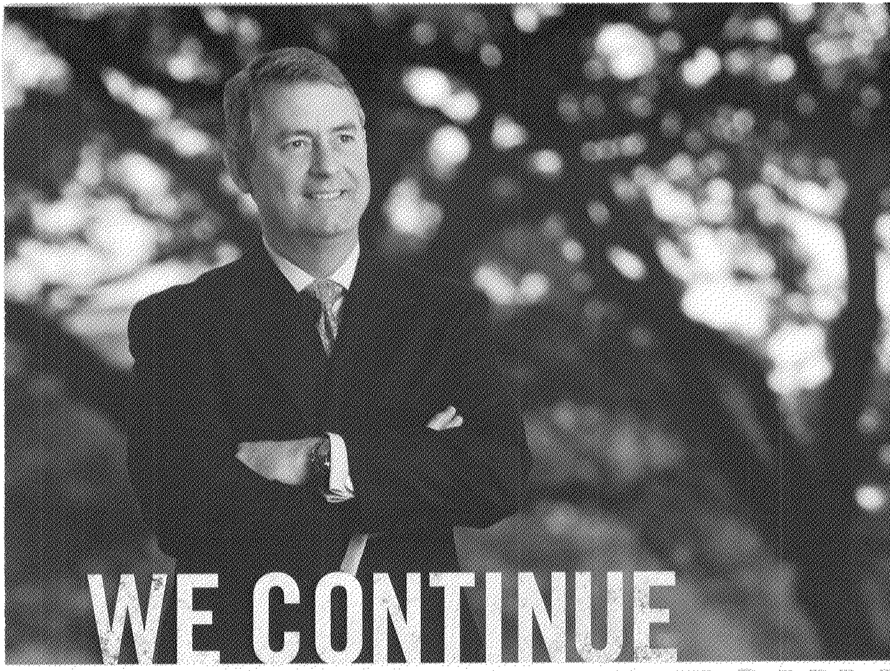


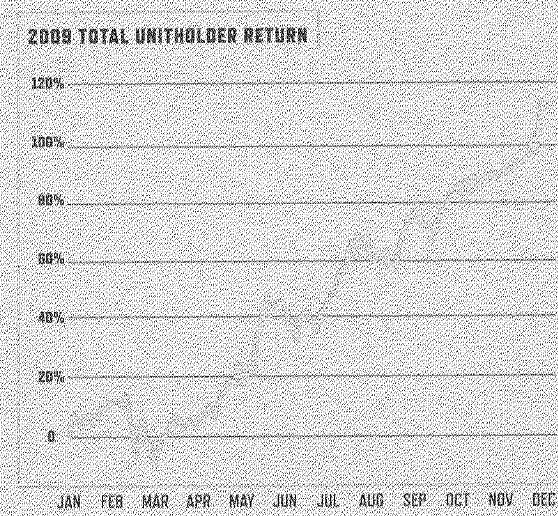
One of the employees playing a pivotal role in our Company's success is Mark Ellis, who brought extensive oil and natural gas operations experience when he joined the Company in 2006. His leadership and business insight have been instrumental in assembling the skilled workforce and long-life assets that have enabled the Company to grow and deliver performance.

As Mark leads the Company as President and Chief Executive Officer, I look forward to working with him and the rest of the LINN team to deliver continued success to our stakeholders. As Executive Chairman, I will focus my efforts at LINN on continuing involvement in the strategic direction of the Company and business development efforts.

Thank you all for your strong support.

MICHAEL C. LINN
Executive Chairman





WE CONTINUE TO DELIVER RESULTS TO OUR UNITHOLDERS.

MESSAGE TO OUR UNITHOLDERS:

I am excited about leading LINN Energy as we continue to build an organization and asset base to drive the Company's growth. I was drawn to the Company by the strategic business model implemented under Mike Linn's leadership, when LINN Energy became the first publicly traded upstream oil and natural gas limited liability company (LLC). The Company focuses exclusively on the United States, which contains the most mature hydrocarbon-producing basins in the world and provides the Company with extensive opportunities to acquire long-life oil and natural gas properties.

In 2009, we delivered a return to our unitholders of more than 100 percent, increased production, generated record levels of adjusted EBITDA and net income, strengthened our balance sheet and hedge portfolio, announced $268 million worth of acquisitions and made a strategic entry into the Permian Basin. LINN's ability to deliver these positive, predictable operating and financial results reflects the Company's focus on its mission to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. To achieve this mission, we have adhered to our tested and proven strategy of efficiently operating and developing our long-life asset base and growing through acquisitions. I am confident that our exceptional group of more than 500 employees will enable us to continue on our path for success.

LINN Energy is the largest independent oil and natural gas master limited partnership/LLC. The Company has the financial flexibility to take advantage of acquisitions that complement our balanced portfolio of low-risk projects and a proven track record of effectively integrating acquired assets. We saw the availability of acquisitions increase during the last half of 2009 and anticipate that trend will continue in 2010.

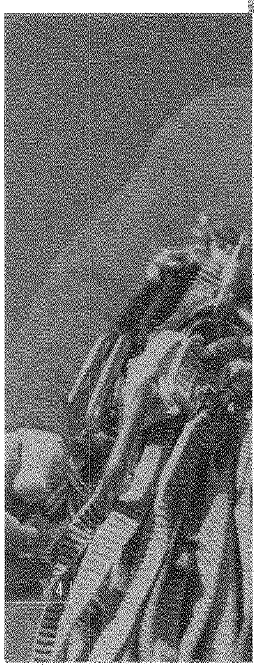
To complement our 2010 acquisition growth strategy, we plan to complete numerous drilling, workover and optimization projects. Specifically, our 2010 growth plans include drilling horizontal wells in the Granite Wash area, which we believe is one of the most economic conventional plays in the United States. Success in this play, along with continued development of the Company's extensive project inventory, will provide material organic growth opportunities for many years.

I would like to thank our unitholders for their investment in LINN Energy. **I am confident that we have built a solid foundation that will enable us to reach new heights.**

Mark E. Ellis

MARK E. ELLIS
President and Chief Executive Officer

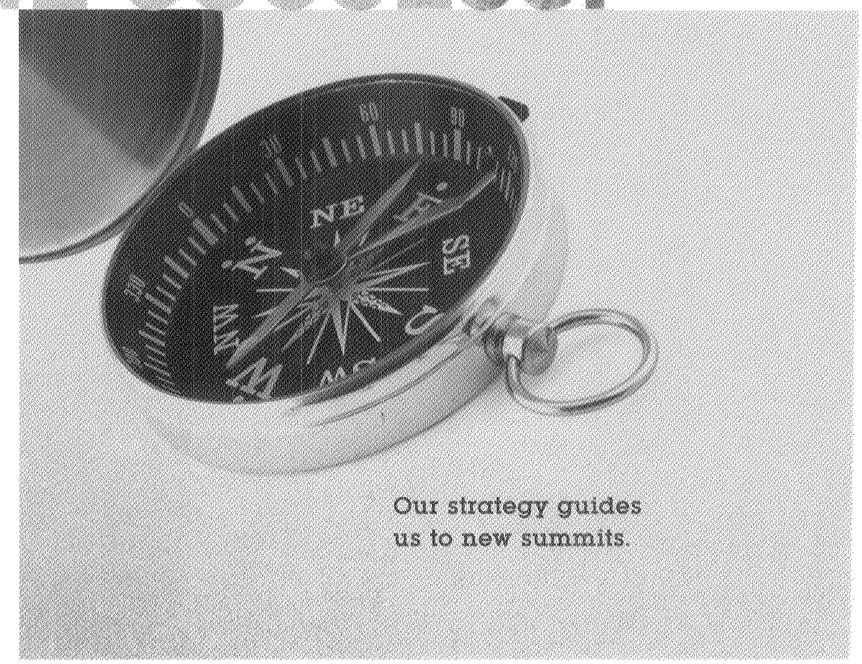
THE RIGHT PEOPLE, ASSETS AND STRATEGY DETERMINE SUCCESS.

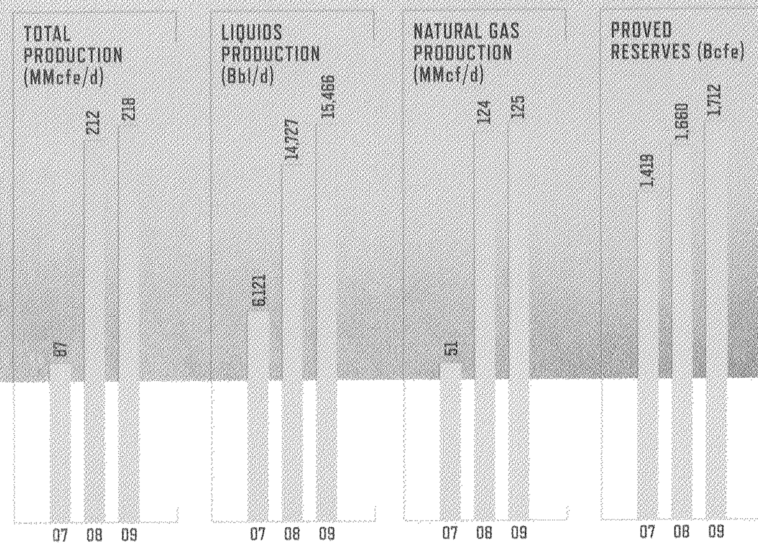


PRODUCTION AND RESERVE GROWTH

LINN Energy's diversified asset base consists of three operating areas and interests in more than 6,900 producing wells across the United States. The Company also has a multi-year inventory of development opportunities to maintain and grow its production and reserves.

The Company invested approximately $150 million on capital projects in 2009, which included drilling 73 wells and completing more than 210 facility, workover and recompletion projects. LINN's focus on these projects enabled the Company to increase daily production by 3 percent to 218 MMcfe/d in 2009 from 212 MMcfe/d in 2008, even with shut-ins and deferred completions in the Granite Wash area during the last half of the year due to low natural gas prices.





Through drillbit and workover activities, LINN replaced 112 percent of production at a very attractive finding and development cost of $1.59 per Mcfe. In addition, the Company made a strategic entry into the Permian Basin through acquisitions totaling $114 million for producing properties in Texas and New Mexico. These combined activities enabled the Company to achieve a reserve-replacement ratio of approximately 189 percent at a reserve-replacement cost of $1.71 per Mcfe (both cases exclude price-related revisions).

In total, LINN increased proved reserves by 3 percent, from 1,660 Bcfe at year-end 2008 to 1,712 Bcfe at year-end 2009. The Company's proved reserves are 71 percent proved developed and comprised of approximately 36 percent oil, 19 percent NGL and 45 percent natural gas. At current production levels, LINN has a long proved reserve-life index of more than 20 years.

CONTINUED ORGANIC GROWTH — 2010 CAPITAL PROGRAM

LINN's deep inventory of opportunities position the Company to continue its successful development programs in 2010. With a 2010 capital program of $155 million, LINN will focus on drilling its highest-return oil and natural gas projects and completing more than 400 workover, recompletion and optimization projects. A significant amount of the Company's drilling capital will go toward its horizontal drilling program in the prolific Granite Wash play. A portion of LINN's acreage is located within the Greater Stiles Ranch area, where recent industry activity has delivered initial production rates in excess of 20 MMcfe/d. The Company expects to see production growth from its Granite Wash drilling program in the last half of 2010.

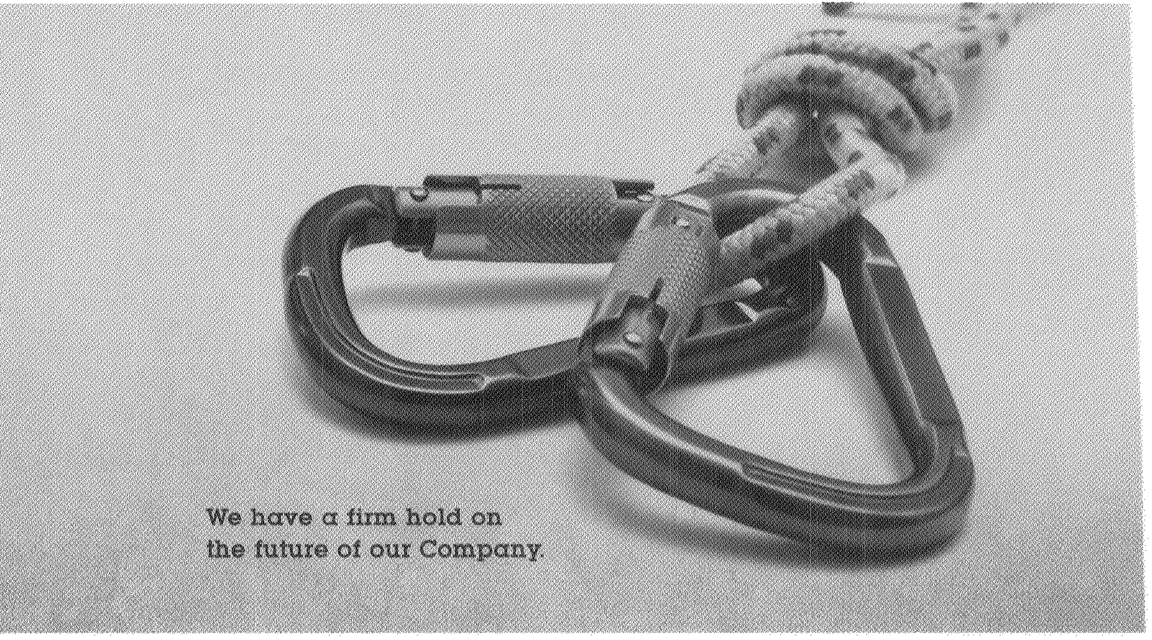
MID-CONTINENT

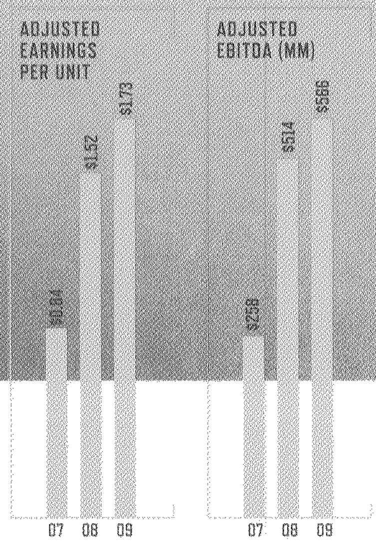
LINN's largest area of operations is the Mid-Continent. The Company's Mid-Continent Deep region includes the Texas Panhandle Granite Wash formation and deep formations in Oklahoma and Kansas. The Mid-Continent Shallow region includes the Texas Panhandle Brown Dolomite formation and shallow formations in Oklahoma, Louisiana and Illinois.

Mid-Continent Deep

The Mid-Continent Deep properties produce at depths ranging from 8,000 feet to 16,000 feet. This region represented approximately 47 percent of the Company's total proved reserves at year-end, and its proved reserves are 71 percent proved developed. Production from this area in 2009 was 135 MMcfe/d, which was 62 percent of the companywide total. LINN has allocated approximately 60 percent of its total 2010 capital program to this region to perform approximately 300 workover and recompletion projects and drill 35 wells.

Mid-Continent Deep assets include the Granite Wash play, which covers a trend extending from the Texas Panhandle eastward into southwestern Oklahoma. LINN's large acreage position in the Texas Panhandle is approximately 70,000 gross acres, or 50,000 net acres, and approximately 90 percent is held by production. The Company is an experienced and active driller in the Granite Wash, with more than 370 vertical wells across this large play.





The industry recently started drilling horizontal wells to unlock more natural gas potential from the Granite Wash play, which consists of multiple natural-gas-charged, stacked-sand deposits that are up to 3,000 feet thick and produce at depths of 12,000 feet to more than 15,000 feet. Wells drilled utilizing horizontal drilling technology typically generate substantially higher initial production rates and reserves than wells drilled utilizing conventional vertical drilling technology. Adding to the attraction of the area, wells produce large volumes of condensate and NGL — significantly increasing the rate-of-return. These results have made the Granite Wash one of the most economically attractive areas in the industry.

In the Company's Texas Panhandle Granite Wash acreage, LINN has identified more than 100 potential horizontal drilling locations and multiple vertical infill drilling locations. The Company has allocated approximately one third of its 2010 capital program to the Granite Wash area for drilling numerous horizontal wells.

LINN also holds a significant acreage position of more than 800,000 gross acres, or 400,000 net acres, in the Anadarko Basin in Oklahoma and southern Kansas, with 89 percent of this total acreage held by production. LINN plans to drill several wells in the Tuttle area of southwestern Oklahoma, and complete numerous workover, recompletion and optimization projects within this area in 2010.

Mid-Continent Shallow

LINN's Mid-Continent Shallow region consists primarily of oil and natural gas wells producing from depths of approximately 3,200 feet in the Texas Panhandle and oil wells at depths of less than 8,000 feet in Oklahoma, Kansas, Louisiana and Illinois. A total of 78 percent of this region's proved reserves are oil and NGL. The proved reserves in this region are 66 percent proved developed and represented approximately 38 percent of our total proved reserves at year-end 2009. This region produced 67 MMcfe/d in 2009, which was 31 percent of the companywide total. LINN has allocated more than 20 percent of its total 2010 capital program to this region to drill and perform workover and recompletion projects.

Wells in the Texas Panhandle shallow produce oil and natural gas from the Brown Dolomite formation. Production from this reservoir has a high BTU content — resulting in a significant amount of NGL extraction, which increases the rate-of-return for these projects. In this area, LINN holds approximately 124,000 gross acres, or 113,000 net acres, all of which are held by production. LINN has been an active driller in this area since 2007 — drilling more than 160 new wells and adding lateral segments to more than 70 existing natural gas wells.

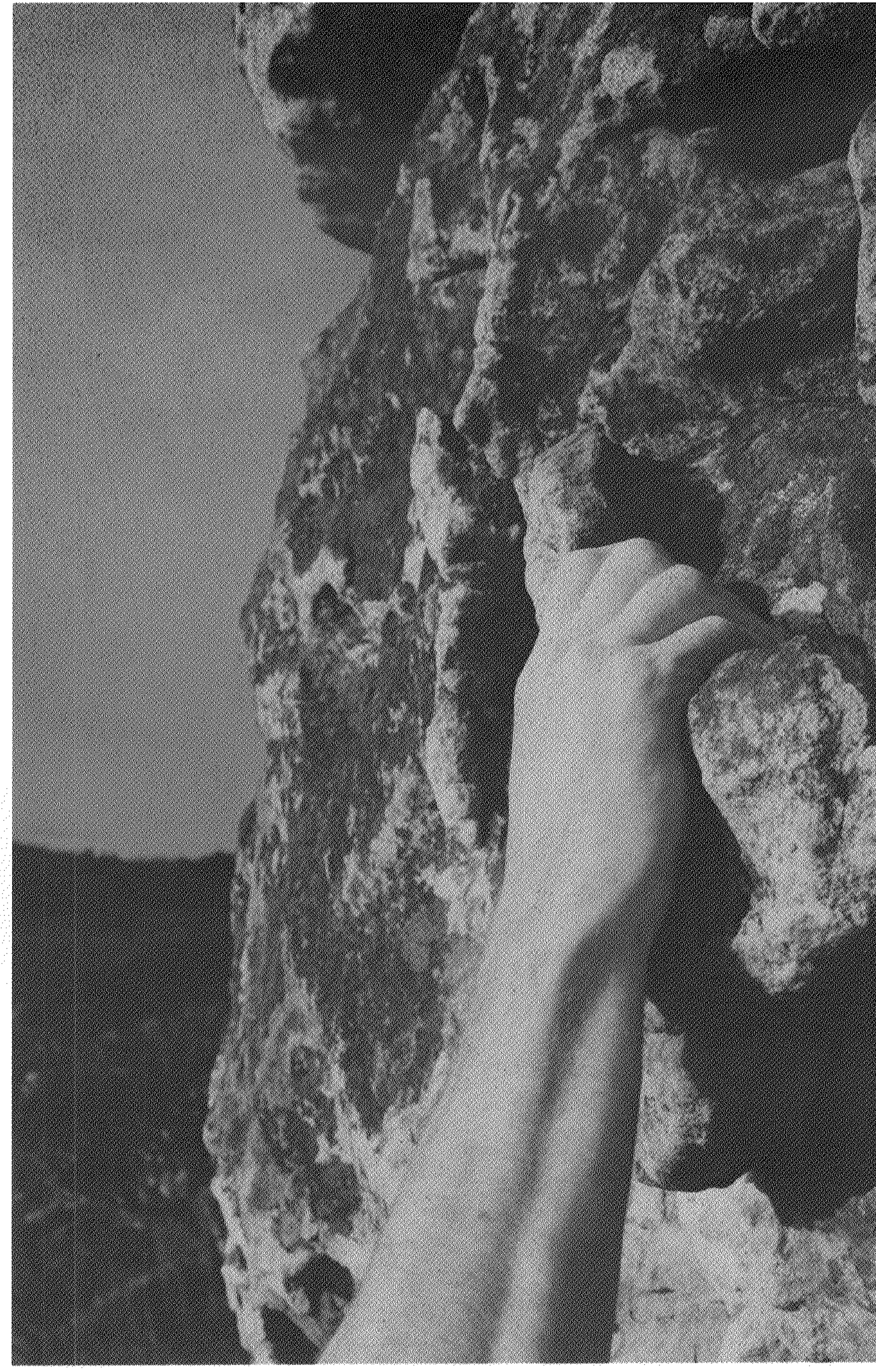
LINN also has a number of shallow, primarily oil properties in southern and northeastern Oklahoma, as well as portions of Louisiana and Illinois. These consist of several waterflood properties, including the Naval Reserve and Osage Hominy Units in Osage County, Oklahoma, along with several properties in the Shoveltum area of southern Oklahoma. These low decline rate oil properties provide LINN with a significant number of opportunities to increase production through low-risk, capital-efficient optimization projects across the operating area.

PERMIAN BASIN

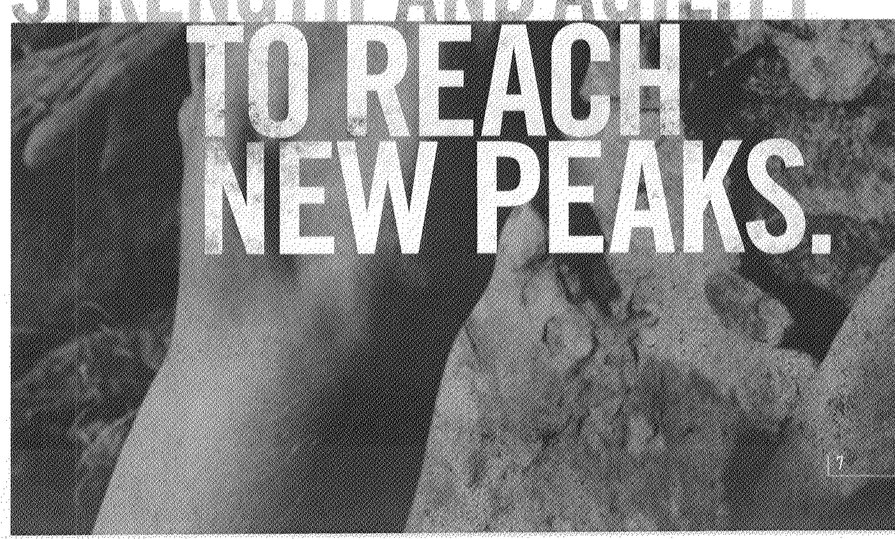
In the second half of 2009, LINN announced three separate transactions for a total contract price of approximately $268 million, whereby the Company acquired oil and natural gas properties located primarily in the Permian Basin. These combined assets as of year-end (pro forma for the acquisition closed in January 2010) provide for current net production from the Permian Basin of more than 14 MMcfe/d and proved reserves of more than 116 Bcfe. Proved reserves are approximately 86 percent liquids and 68 percent proved developed, with a reserve-life index of more than 20 years. These properties also provide an inventory of more than 250 infill-development wells and low-risk optimization projects. LINN anticipates that operating within this area will provide many opportunities for future bolt-on acquisitions that will enable the Company to expand this as a core operating area. LINN has allocated approximately 20 percent of its total 2010 capital program to Permian Basin operations to complete optimization projects and to drill 30 development wells.

CALIFORNIA

Operations in California are within the Brea Olinda Field of the Los Angeles Basin. This field is primarily an oil asset with a very low decline rate of approximately 3 percent per year. The Brea Olinda Field was discovered in 1880 and produces from the shallow Pliocene formation and the deeper Miocene formation at depths of 1,000 feet to 7,500 feet. Proved reserves for this area are 94 percent proved developed and represented approximately 11 percent of LINN's total proved reserves at year-end. Production was 14 MMcfe/d in 2009, or 6 percent of the companywide total. This area routinely provides the Company with low-cost oil optimization opportunities.

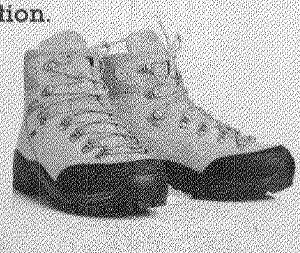


WE HAVE THE STRENGTH AND AGILITY TO REACH NEW PEAKS.



WE ARE DEDICATED TO DELIVERING RETURNS TO OUR INVESTORS.

Our sound strategy and dedicated employees give us the solid footing we need to move forward in any situation.



FINANCIAL OVERVIEW

During 2009, LINN generated adjusted EBITDA (a Non-GAAP financial measure) of $566 million, which was a 10-percent increase from the prior year. Additionally, adjusted net income for 2009 increased by 18 percent to $207 million.

The Company proactively amended and restated its credit facility in 2009 to extend the maturity date to 2012. The Company also opportunistically accessed the capital markets through two public equity offerings and a bond offering that provided net proceeds of approximately $510 million. The offerings provided funding for acquisitions completed in late 2009 and early 2010, while also positioning the Company with the financial flexibility to continue to pursue its acquisition growth strategy. At year-end, the Company had undrawn capacity of $559 million, including available cash.

LINN has strengthened and expanded its hedge portfolio. Current oil, NGL and natural gas production levels are hedged at approximately 100 percent on an equivalent basis through 2011, and 65 percent of oil production is hedged in 2012 and 2013. For 2010, the Company's production is hedged at a weighted average price of $99.68 per barrel and $8.66 per Mcf and for 2011, at a weighted average price of $82.50 per barrel and $9.25 per Mcf. For 2012 and 2013, oil production is hedged at a weighted average price of $100 per barrel, and these hedges are extendible into 2014, 2015 and 2016.

ATTRACTIVE INVESTMENT AND INCOME OPPORTUNITY

LINN's units represent an attractive yield with no incentive distribution rights (IDRs), which allow LINN's investors to share equally in all cash flow. Since LINN's initial public offering in January 2006, the Company has paid a tax-advantaged cash distribution each quarter and increased its cash distribution by 58 percent. In 2009, LINN delivered a total unitholder return of more than 100 percent and paid an annual cash distribution of $2.52 per unit.

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

Form 10-K

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

For the fiscal year ended December 31, 2009

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

Commission file number: 000-51719

LINN Energy

LINN ENERGY, LLC

(Exact name of registrant as specified in its charter)

Delaware	**65-1177591**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
600 Travis, Suite 5100 **Houston, Texas**	**77002**
(Address of principal executive offices)	*(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 Global Select Market

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 ☒ No ☐

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 ☐ No ☒

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ☐ No ☐

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. ☐

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 ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check-mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes ☐ No ☒

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $2,303,614,114 on June 30, 2009, based on $19.57 per unit, the last reported sales price of the units on The NASDAQ Global Select Market on such date.

As of January 29, 2010, there were 130,566,930 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 April 27, 2010.

TABLE OF CONTENTS

		Page
	Glossary of Terms	ii
	Part I	
Item 1.	Business	1
Item 1A.	Risk Factors	13
Item 1B.	Unresolved Staff Comments	26
Item 2.	Properties	26
Item 3.	Legal Proceedings	26
Item 4.	Submission of Matters to a Vote of Security Holders	26
	Part II	
Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	29
Item 6.	Selected Financial Data	32
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	34
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	64
Item 8.	Financial Statements and Supplementary Data	65
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	113
Item 9A.	Controls and Procedures	113
Item 9B.	Other Information	113
	Part III	
Item 10.	Directors, Executive Officers and Corporate Governance	114
Item 11.	Executive Compensation	114
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	114
Item 13.	Certain Relationships and Related Transactions, and Director Independence	114
Item 14.	Principal Accounting Fees and Services	114
	Part IV	
Item 15.	Exhibits and Financial Statement Schedules	115
	Signatures	116

GLOSSARY OF TERMS

As commonly used in the oil and natural 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 natural 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 degrees to 59.5 degrees Fahrenheit.

Development well. A well drilled within the proved area of a 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 natural gas to one Bbl of oil, condensate or natural gas liquids.

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

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

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 natural 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.

GLOSSARY OF TERMS - Continued

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

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Additional reserves 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. Reserves that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. In accordance with Securities and Exchange Commission regulations, reserves at December 31, 2009, were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. In accordance with Securities and Exchange Commission regulations, reserves for all prior years were estimated using year-end prices.

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 directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. 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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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 natural gas and/or oil 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 regulations of the Securities and Exchange Commission, 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 natural 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, natural gas and NGL regardless of whether such acreage contains proved reserves.

Unproved reserves. Reserves that are considered less certain to be recovered than proved reserves. Unproved reserves may be further sub-classified to denote progressively increasing uncertainty of recoverability and include probable reserves and possible reserves.

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

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

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 Item 8. "Financial Statements and Supplementary Data."

Overview

LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. LINN Energy is an independent oil and natural gas company that began operations in March 2003 and completed its initial public offering ("IPO") in January 2006. The Company's properties are located in the United States, primarily in the Mid-Continent, California and the Permian Basin.

Proved reserves at December 31, 2009, were 1,712 Bcfe, of which approximately 36% were oil, 45% were natural gas and 19% were natural gas liquids ("NGL"). Approximately 71% were classified as proved developed, with a total standardized measure of discounted future net cash flows of $1.72 billion. At December 31, 2009, the Company operated 4,688, or 68%, of its 6,931 gross productive wells and had an average proved reserve-life index of approximately 22 years, based on the December 31, 2009, reserve report and annualized production for the three months ended December 31, 2009.

In January 2010, the Company completed an acquisition of oil and natural gas properties in the Anadarko and Permian Basins for a contract price of $154.5 million. See "Recent Developments" below for additional details. On a pro forma basis, including this acquisition, total proved reserves at December 31, 2009, were 1,785 Bcfe, of which approximately 37% were oil, 44% were natural gas and 19% were NGL.

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:

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

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

Grow Through Acquisition of Long-Life, High Quality Properties

The Company's acquisition program targets oil and natural gas properties that are financially accretive and offer stable, 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, development costs and rate of return. As part of this strategy, the Company continually seeks to optimize its asset portfolio, which may include the divestiture of noncore assets. This allows the Company to redeploy capital into projects to develop lower-risk, long-life and low-decline properties that are better suited to its business strategy.

From inception through the date of this report, excluding 15 acquisitions comprising the Appalachian Basin properties sold in July 2008, the Company has completed 13 acquisitions of working and royalty interests in oil and natural gas properties and related gathering and pipeline assets. Total acquired proved reserves were approximately 1.8 Tcfe at the time of acquisition at an acquisition cost of approximately $2.15 per Mcfe. The Company finances acquisitions with a combination of funds from equity and debt offerings, bank borrowings and cash generated from operations. See Note 2 for additional details about the Company's acquisitions and divestitures.

Efficiently Operate and Develop Acquired Properties

The Company has centralized 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. In addition, the Company seeks to deliver attractive financial returns by leveraging its experienced workforce and scalable infrastructure. For 2010, the Company estimates its capital expenditures, excluding acquisitions, will be between $150.0 million and $175.0 million. This estimate is under continuous review and is subject to ongoing 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, natural gas and NGL and provide long-term cash flow predictability to pay distributions, service debt and manage its business. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices.

These transactions are primarily in the form of swap contracts, put options and collars that are designed to provide a fixed price (swap contracts), fixed price floor with opportunity for upside (put options) or range of prices between a price floor and a price ceiling (collars) that the Company will receive as compared to floating market prices. The Company has derivative contracts in place for 2010 and 2011 at average prices of $99.68 per Bbl and $82.50 per Bbl for oil and $8.66 per MMBtu and $9.25 per MMBtu for natural gas, respectively. Additionally, the Company has derivative contracts in place covering substantially all of its exposure to the Mid-Continent natural gas basis differential.

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 (as defined in Note 6) from a floating rate to a fixed rate. At January 29, 2010, the Company had LIBOR swaps in place at an average fixed rate of 3.85% through January 2014. For additional details about the Company's interest rate swap agreements and commodity derivative contracts, see 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 7 and Note 8.

Recent Developments

Commodity Derivatives

In February 2010, the Company entered into fixed price oil swaps on an additional 5,250 Bbls per day at a price of $100.00 per Bbl for the years ending December 31, 2012, and December 31, 2013, bringing the Company's total such fixed price oil swaps to swaps on 7,250 Bbls per day. The Company has derivative contracts that extend the swaps for each of the years ending December 31, 2014, December 31, 2015, and December 31, 2016, if the counterparties determine that the strike prices are in-the-money on a designated date in each respective preceding year. The extension for each year is exercisable without respect to the other years. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional details.

Acquisitions

On January 29, 2010, the Company completed the acquisition of certain oil and natural gas properties located in the Anadarko Basin in Oklahoma and Kansas and the Permian Basin in Texas and New Mexico, from certain affiliates of Merit Energy Company ("Merit") for a contract price of $154.5 million. The transaction was financed with borrowings under the Company's Credit Facility. The acquisition provides a strategic addition to the Company's asset portfolio in the Permian Basin and Mid-Continent, and includes approximately 12 MMBoe (73 Bcfe) of proved reserves as of the acquisition date, primarily oil.

On August 31, 2009, and September 30, 2009, the Company completed the acquisitions of certain oil and natural gas properties located in the Permian Basin in Texas and New Mexico from Forest Oil Corporation and Forest Oil Permian Corporation (collectively referred to as "Forest"). The Company paid $114.4 million in cash, net of cash received from Forest post-closing, and recorded a receivable from Forest, resulting in total consideration for the acquisitions of approximately $113.7 million. The transactions were financed with borrowings under the Company's Credit Facility. The acquisitions represent a strategic entry into the Permian Basin for the Company, and include approximately 10 MMBoe (62 Bcfe) of proved reserves, primarily oil.

Distributions

On January 27, 2010, the Company's Board of Directors declared a cash distribution of $0.63 per unit with respect to the fourth quarter of 2009. The distribution, totaling approximately $82.3 million, was paid on February 12, 2010, to unitholders of record as of the close of business on February 5, 2010.

Operating Regions

Inclusive of the properties acquired from Merit in January 2010 (see "Acquisitions" above), the Company's properties are located in four regions in the United States:

- Mid-Continent Deep, which includes the Texas Panhandle Deep Granite Wash formation and deep formations in Oklahoma and Kansas;
- Mid-Continent Shallow, which includes the Texas Panhandle Brown Dolomite formation and shallow formations in Oklahoma, Louisiana and Illinois;
- California, which includes the Brea Olinda Field of the Los Angeles Basin; and
- Permian Basin, which includes areas in West Texas and Southeast New Mexico.

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 and Kansas, which produce at depths of more than 8,000 feet. Mid-Continent Deep proved reserves represented approximately 47% of total proved reserves at December 31, 2009, of which 71% were classified as proved developed reserves.

This region produced 135 MMcfe/d, or 62%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $99.3 million to drill in this region. During 2010, the Company anticipates spending approximately 60% 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 and properties in Oklahoma, Louisiana and Illinois, which produce at depths of less than 8,000 feet. Mid-Continent Shallow proved reserves represented approximately 38% of total proved reserves at December 31, 2009, of which 66% were classified as proved developed reserves. This region produced 67 MMcfe/d, or 31%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $21.0 million to drill in this region. During 2010, the Company anticipates spending approximately 20% of its total capital budget for development activities in the Mid-Continent Shallow region.

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

California

The California region consists of the Brea Olinda Field of the Los Angeles Basin. The Brea Olinda Field was discovered in 1880 and produces from the shallow Pliocene formation to the deeper Miocene formation at depths of 1,000 feet to 7,500 feet. California proved reserves represented approximately 11% of total proved reserves at December 31, 2009, of which 94% were classified as proved developed reserves. This region produced 14 MMcfe/d, or 6%, of the Company's 2009 average daily production.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the United States. The Company's properties are located in West Texas and Southeast New Mexico and produce at depths ranging from 2,000 feet to 9,000 feet. Permian Basin proved reserves represented approximately 4% of total proved reserves at December 31, 2009, of which 53% were classified as proved developed reserves. The properties that comprise this region as of December 31, 2009, were acquired in the third quarter of 2009 (see "Acquisitions" above). This region produced 2 MMcfe/d, or 1%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $0.1 million to drill in this region. During 2010, the Company anticipates spending approximately 20% of its total capital budget for development activities in the Permian Basin region.

Drilling and Acreage

The following sets forth the wells drilled in the Mid-Continent Deep, Mid-Continent Shallow, California and Permian Basin 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,		
	2009	**2008**	**2007**
Gross wells:			
Productive	72	304	136
Dry	1	2	2
	73	306	138
Net development wells:			
Productive	35	189	112
Dry	1	1	2
	36	190	114
Net exploratory wells:			
Productive	—	—	—
Dry	—	—	—
	—	—	—

The totals above do not include 25, 23 and 25 lateral segments added to existing vertical wellbores in the Mid-Continent Shallow region during the years ended December 31, 2009, December 31, 2008, and December 31, 2007, respectively. The total wells above exclude 45 and 115 gross wells (45 and 105 net wells) drilled in the Appalachian Basin during the years ended December 31, 2008, and December 31, 2007, respectively. The Company sold its Appalachian Basin properties in July 2008. At December 31, 2009, the Company had one gross (one net) well in process (no wells were temporarily suspended).

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 and the quantities or economic value of reserves found. Productive wells are those that produce commercial quantities of oil, natural 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, 2009:

	Total [1]
Proved undeveloped	1,241
Other locations	3,050
Total drilling locations	4,291
Leasehold interests – net acres (in thousands)	702

[1] Does not include optimization projects.

As shown in the table above, as of December 31, 2009, the Company had 1,241 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 3,050 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.

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, 2009. 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 2,100 productive wells in which the Company owns a royalty interest only.

	Natural Gas Wells		Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated [(1)]	1,947	1,534	2,741	2,523	4,688	4,057
Nonoperated [(2)]	1,201	207	1,042	72	2,243	279
	3,148	1,741	3,783	2,595	6,931	4,336

(1) 10 operated wells had multiple completions at December 31, 2009.

(2) Three nonoperated wells had multiple completions at December 31, 2009.

Developed and Undeveloped Acreage

The following sets forth information as of December 31, 2009, relating to leasehold acreage:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
			(in thousands)			
Leasehold acreage	1,462	648	90	54	1,552	702

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 for additional information). Unless otherwise indicated, results of operations information presented herein relates only to continuing operations.

The Company's natural gas production is primarily sold under market sensitive price contracts, which typically sell at a differential to New York Mercantile Exchange ("NYMEX"), Panhandle Eastern Pipeline ("PEPL"), or El Paso Permian Basin natural gas prices due to the Btu content and the proximity to major consuming markets. The Company's natural 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 natural gas and NGL recovered after transportation and processing of natural gas. These purchasers sell the residual natural gas and NGL based primarily on spot market prices. Under percentage-of-index contracts, the price per MMBtu the Company receives for natural gas is tied to indexes published in *Gas Daily* or *Inside FERC Gas Market Report.* Although exact percentages vary daily, as of December 31, 2009, approximately 80% of the Company's natural gas and NGL production was sold under short-term contracts at market-sensitive or spot prices. At December 31, 2009, the Company had natural gas throughput delivery commitments under long-term contracts of approximately 2,102 MMcf, 1,045 MMcf and 784 MMcf for the years ended December 31, 2010, December 31, 2011, and December 31, 2012, respectively.

Item 1. Business - Continued

The Company's oil production is primarily sold under market sensitive contracts, which typically sell at a differential to NYMEX, and as of December 31, 2009, approximately 75% of its oil production was sold under short-term contracts. At December 31, 2009, the Company had no delivery commitments for oil production.

As discussed in the "Strategy" section above, the Company enters into derivative contracts primarily in the form of swap contracts, put options and collars to reduce the impact of commodity price volatility on its cash flow from operations. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flow due to fluctuations in commodity prices.

The following sets forth information regarding average daily production, average prices and average costs, from continuing operations, for each of the periods indicated:

	Year Ended December 31,		
	2009	**2008**	**2007**
Average daily production:			
Natural gas (MMcf/d)	125	124	51
Oil (MBbls/d)	9.0	8.6	3.4
NGL (MBbls/d)	6.5	6.2	2.7
Total (MMcfe/d)	218	212	87
Weighted average prices (hedged): [(1)]			
Natural gas (Mcf)	$ 8.27	$ 8.42	$ 8.36
Oil (Bbl)	$ 110.94	$ 80.92	$ 67.07
NGL (Bbl)	$ 28.04	$ 57.86	$ 55.51
Weighted average prices (unhedged): [(2)]			
Natural gas (Mcf)	$ 3.51	$ 7.39	$ 6.39
Oil (Bbl)	$ 55.25	$ 92.78	$ 66.44
NGL (Bbl)	$ 28.04	$ 57.86	$ 55.51
Average NYMEX prices:			
Natural gas (MMBtu)	$ 3.99	$ 9.04	$ 6.86
Oil (Bbl)	$ 61.94	$ 99.65	$ 72.34
Costs per Mcfe of production:			
Lease operating expenses	$ 1.67	$ 1.49	$ 1.31
Transportation expenses	$ 0.23	$ 0.23	$ 0.17
General and administrative expenses [(3)]	$ 1.08	$ 1.00	$ 1.61
Depreciation, depletion and amortization	$ 2.53	$ 2.50	$ 2.16
Taxes, other than income taxes	$ 0.35	$ 0.79	$ 0.70

(1) Includes the effect of realized gains on derivatives of $401.0 million (excluding $49.0 million realized net gains on canceled contracts), $9.4 million (excluding $81.4 million realized losses on canceled contracts) and $37.3 million for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, respectively. The Company utilizes oil puts to hedge revenues associated with its NGL production; therefore, all realized gains on oil derivative contracts are included in weighted average oil prices, rather than weighted average NGL prices.

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

(3) General and administrative expenses for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, include approximately $14.7 million, $14.6 million and $13.5 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, were $0.90 per Mcfe, $0.81 per Mcfe and $1.19 per Mcfe, respectively. This measure is not in accordance with United States Generally Accepted Accounting Principles ("GAAP") and thus is a non-GAAP measure, used by management to analyze the Company's performance.

Reserve Data

Modernization of Oil and Natural Gas Reporting Requirements

Effective for fiscal years ending on or after December 31, 2009, the Securities and Exchange Commission ("SEC") approved revisions designed to modernize reserve reporting requirements for oil and natural gas companies. In addition, effective for the same period, the Financial Accounting Standards Board issued Accounting Standards Codification Update 2010-03, "*Extractive Activities – Oil and Gas (Topic 932) – Oil and Gas Reserve Estimation and Disclosures*," to provide consistency with the new SEC rules. The Company adopted the new requirements effective December 31, 2009. The most significant amendments to the requirements include the following:

- commodity prices – economic producibility of reserves estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions;
- 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
- nontraditional resources – the definition of oil and natural gas producing activities were expanded and focus on the marketable product rather than the method of extraction.

Proved Reserves

The following sets forth estimated proved oil, natural gas and NGL reserves and the standardized measure of discounted future net cash flows at December 31, 2009, based on reserve reports prepared by independent engineers DeGolyer and MacNaughton:

Estimated proved developed reserves:	
Natural gas (Bcf)	549
Oil (MMBbls)	78
NGL (MMBbls)	34
Total (Bcfe)	1,220
Estimated proved undeveloped reserves: (1)	
Natural gas (Bcf)	225
Oil (MMBbls)	24
NGL (MMBbls)	20
Total (Bcfe)	492
Estimated total proved reserves (Bcfe)	1,712
Proved developed reserves as a percentage of total proved reserves	71%
Standardized measure of discounted future net cash flows (in millions) (2)	$ 1,723
Representative NYMEX prices: (3)	
Natural gas (MMBtu)	$ 3.87
Oil (Bbl)	$ 61.05

(1) During the year ended December 31, 2009, the Company incurred approximately $52.7 million in capital expenditures to convert 33 Bcfe of reserves previously classified as proved undeveloped into proved developed reserves at December 31, 2009.

(2) This measure is not intended to represent the market value of estimated reserves.

(3) In accordance with SEC regulations, reserves were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and NGL 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, natural gas and NGL that are ultimately recovered. 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 under the provisions of applicable accounting standards 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 natural 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.

The reserve estimates reported herein were prepared by independent engineers DeGolyer and MacNaughton. 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, based in part on data provided by the Company. When preparing the reserve estimates, the independent engineering firm did not independently verify the accuracy and completeness of information and data furnished by the Company with respect to ownership interests, 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 that 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. The 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. The independent engineering firm 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 SEC staff interpretations and guidance.

The Company's internal control over the preparation of reserve estimates is a process designed to provide reasonable assurance regarding the reliability of the Company's reserve estimates in accordance with SEC regulations. The preparation of reserve estimates was overseen by the Company's Reservoir Engineering Advisor, who has Master of Petroleum Engineering and Master of Business Administration degrees and more than 25 years of oil and natural gas industry experience. The reserve estimates were reviewed and approved by the Company's senior engineering staff and management, with final approval by its Senior Vice President and Chief Operating Officer. For additional information regarding estimates of reserves, including the standardized measure of discounted future net cash flows, see "Supplemental Oil and Natural Gas Data (Unaudited)" in Item 8. "Financial Statements and Supplementary Data."

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, 2009, sales of oil, natural gas and NGL to DCP Midstream Partners, LP, Enbridge Energy Partners, L.P. and ConocoPhillips accounted for approximately 25%, 19% and 12%, respectively, of the Company's total volumes, or 56% in the aggregate. If the Company were to lose any one of its major oil and natural gas purchasers, the loss could temporarily cease or delay production and sale of its oil and natural 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 purchasers ceased purchasing oil and natural gas altogether, it could have a detrimental effect on the oil and natural gas market in general and on the volume of oil and natural gas that the Company is able to sell.

Competition

The oil and natural 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 natural 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 natural 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. 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 addition, the Company participates in wells on a nonoperated basis and therefore may be limited in its ability to control the risks associated with the operation of such wells.

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 has elected to self-insure for certain items for which it has 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. For more information about potential risks that could affect the Company see Item 1A. "Risk Factors."

Title to Properties

Prior to the commencement of drilling operations, the Company conducts a 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 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 properties and believes that it has satisfactory title to its producing properties in accordance with standards generally accepted in the industry. Oil and natural 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 in which the Company operates. 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 natural gas typically decreases during the summer months and increases during the winter months. Seasonal anomalies sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand fluctuations.

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 natural gas industry. These laws and regulations may:

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment;
- 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, natural gas and NGL production below the rate that would otherwise be possible. The regulatory burden on the 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 cleanup requirements for the oil and natural 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 and excavations within the 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 natural 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
- United States 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, natural gas and NGL, 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 resources. States may regulate rates of production and may establish maximum daily production allowables from natural 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, natural 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 natural 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 regulatory issues that could impact the Company include new rules or legislation regulating greenhouse gas emissions to address climate change, such as a proposed cap-and-trade program and the Environmental Protection Agency's ("EPA") recent endangerment finding regarding several greenhouse gases, including carbon dioxide, as well as regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process.

In June 2009, the United States House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill. The United States Senate's version, The Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, has been introduced, but has not passed. Although these bills include several differences that require reconciliation before becoming law, both bills contain the basic feature of establishing a cap-and-trade system for restricting greenhouse gas emissions in the United States. Under such system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission allowances corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of this legislative initiative remains uncertain. In addition to the pending climate legislation, the EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The EPA has proposed regulation that would require permits for and reductions in greenhouse gas emissions for certain facilities, and may issue final rules this year. Any laws or regulations that may be adopted to restrict or reduce emissions of United States greenhouse gases could require the Company to incur increased operating costs, and could have an adverse effect on demand for oil and natural gas.

The Company cannot predict how future environmental laws and regulations may impact its properties or operations. For the year ended December 31, 2009, 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 2010 or that will otherwise have a material impact on its financial position or results of operations.

Employees

As of December 31, 2009, the Company employed approximately 550 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, natural gas and NGL reserves;
- realized oil, natural 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 Item 1. "Business;" Item 1A. "Risk Factors;" 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," "believe," "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 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.

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, or at all, 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, natural gas and NGL;
- prices at which oil, natural 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;
- access to credit or capital markets;
- renegotiation of our Credit Facility at existing terms and pricing; 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, or the distribution may be suspended.

We actively seek to acquire oil and natural gas properties. Acquisitions involve potential risks that could adversely impact our future growth and our ability to increase or pay distributions at the current level, or at all.

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;
- 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, 2017 Notes and 2018 Notes (each as defined in Note 6). Our Credit Facility has substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations, our ability to make acquisitions and our ability to pay distributions to our unitholders.

We have significant indebtedness under our Credit Facility, 2017 Notes and 2018 Notes. As of January 29, 2010, we had an aggregate of approximately $1.7 billion outstanding under our Credit Facility, 2017 Notes and 2018 Notes (with additional borrowing capacity of approximately $422.0 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, enter into commodity and interest rate derivative contracts 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 flow for drilling and development of oil and natural 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. In addition, we may finance acquisitions through borrowings under our Credit Facility or the incurrence of additional debt. To the extent that we are unable to incur additional debt under our Credit Facility or otherwise because we are not in compliance with the financial covenants in the Credit Facility, we may not be able to complete acquisitions, which could adversely affect our ability to maintain or increase distributions.

Availability under our Credit Facility is determined semi-annually at the discretion of the lenders and is based in part on oil, natural gas and NGL prices. Significant declines in oil, natural 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, natural 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.

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, our ability to make acquisitions 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 and we are unable to effectively hedge our interest rate risk, 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, natural gas and NGL, we enter into commodity derivative contracts for a significant portion of our production. Commodity derivative arrangements expose us to the risk of financial loss in some circumstances, including situations when the other party to the contract defaults on its contract or production is less than expected. 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, which may adversely affect our ability to pay distributions to our unitholders.

Disruptions in the capital and credit markets 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, natural gas and NGL. The oil, natural 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, natural 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, natural gas and NGL;
- the price and level of foreign imports;
- the level of consumer product demand;
- weather conditions;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural 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 United States dollar exchange rates on oil, natural 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, natural 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, which could adversely affect our results of operations and limit our ability to borrow funds.

Declines in oil, natural 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 noncash charge to earnings, the carrying value of our properties for impairments. We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. 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, natural 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, natural gas and NGL reserves and production and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing 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, natural gas and NGL in an exact way. Reserve engineering requires subjective estimates of underground accumulations of oil, natural gas and NGL and assumptions concerning future oil, natural 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, natural 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, natural gas and NGL attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil, natural 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, natural gas and NGL reserves. We base the estimated discounted future net cash flows from our proved reserves on an unweighted average of the first-day-of-the month price for each month during the 12-month calendar year and year-end costs. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

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

In addition, the 10% discount factor, required to be used under the provisions of applicable accounting standards 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 natural 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 natural 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, natural 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, natural gas and NGL we are able to produce from existing wells;
- the prices at which we are able to sell our oil, natural 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, natural 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, natural 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, natural 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. In addition, the SEC's reserve reporting rules include a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. At December 31, 2009, we had 1,241 proved undeveloped drilling locations. To the extent that we do not drill these prospects within five years of initial booking, they may not continue to qualify for classification as proved reserves, and we may be required to reclassify such reserves as unproved reserves. The reclassification of such reserves could also have a negative effect on the borrowing base under our Credit Facility.

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, natural gas and NGL to be commercially viable after drilling, operating and other costs. If we drill future wells that we identify as dry holes, our drilling success rate would decline, which could have an adverse effect on our business, financial 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, natural gas and NGL we produce, and could reduce our cash available for distribution and adversely impact expected increases in oil, natural gas and NGL production from our drilling program.

The marketability of our oil, natural gas and NGL production depends in part on the availability, proximity and capacity of gathering and pipeline systems. The amount of oil, natural 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, natural 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, natural gas and NGL we produce, and could reduce our cash available for distribution and adversely impact expected increases in oil, natural gas and NGL production from our drilling program.

We depend on certain key customers for sales of our oil, natural 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 nonpayment could have an adverse impact on our financial position and results of operations.

For the year ended December 31, 2009, DCP Midstream Partners, LP, Enbridge Energy Partners, L.P. and ConocoPhillips accounted for approximately 25%, 19% and 12%, respectively, of our total volumes, or 56% in the aggregate. For the year ended December 31, 2008, DCP Midstream Partners, LP, ConocoPhillips and Enbridge Energy Partners, L.P. accounted for approximately 23%, 12% and 11%, respectively, of our total volumes from continuing operations, or 46% in the aggregate. To the extent these and other customers reduce the volumes of oil, natural 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, 2009, we had identified 4,291 drilling locations, of which 1,241 were proved undeveloped locations and 3,050 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, natural gas and NGL prices, costs and drilling results. In addition, DeGolyer and MacNaughton has not estimated proved reserves for the 3,050 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, natural 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, natural 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, natural 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, natural 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, natural 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.

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, and these costs may not be recoverable from insurance. For a more detailed discussion of environmental and regulatory matters impacting our business, see 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 natural 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, natural 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 Item 1. "Business - Environmental Matters and Regulation."

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

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

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

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

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 nonaffiliated 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

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 Internal Revenue Service ("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%. 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. Any modification to current law or interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the requirements for partnership status, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our units.

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.

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

The IRS may adopt tax positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, the costs of any contest with the IRS will be borne indirectly by our unitholders because the costs will reduce our cash available for distribution.

Unitholders are required to pay taxes on their share of our taxable income, including their share of ordinary income and capital gain upon dispositions of properties by us, even if they do not receive any cash distributions from us. A unitholder's share of our taxable income, gain, loss and deduction, or specific items thereof, may be substantially different than the unitholder's interest in our economic profits.

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. For example, we may sell a portion of our properties and use the proceeds to pay down debt or acquire other properties rather than distributing the proceeds to our unitholders, and some or all of our unitholders may be allocated substantial taxable income with respect to that sale.

A unitholder's share of our taxable income upon a disposition of property by us may be ordinary income or capital gain or some combination thereof. Even where we dispose of properties that are capital assets, what otherwise would be capital gains may be recharacterized as ordinary income in order to "recapture" ordinary deductions that were previously allocated to that unitholder related to the same property.

A unitholder's share of our taxable income and gain (or specific items thereof) may be substantially greater than, or our tax losses and deductions (or specific items thereof) may be substantially less than, the unitholder's interest in our economic profits. This may occur, for example, in the case of a unitholder who purchases units at a time when the value of our units or of one or more of our properties is relatively low or a unitholder who acquires units directly from us in exchange for property whose fair market value exceeds its tax basis at the time of the exchange.

A unitholder's taxable gain or loss on the disposition of our units could be more or less than expected.

If unitholders sell their units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those units. Prior distributions to our unitholders in excess of the total net taxable income they were allocated for a unit, which decreases their tax basis, will become taxable income to our unitholders if the unit is sold at a price greater than their tax basis in that unit, even if the price received is less than their original cost.

A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale. If the IRS successfully contests some positions we take, unitholders could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in units by tax-exempt entities, such as individual retirement accounts (known as IRAs) and other retirement plans, and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income.

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

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of our units to a purchaser of units. We take depletion, depreciation and amortization positions that are intended to maintain such uniformity. These depletion, depreciation and amortization positions may not conform with all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from unitholders' sale of units and could have a negative impact on the value of our units or result in audit adjustments to unitholder tax returns.

The sale or exchange of 50% or more of our capital and profits interests within a twelve-month period will result in the deemed termination of our tax partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. If this occurs, our unitholders will be allocated an increased amount of federal taxable income for the year in which we are considered to be terminated as a percentage of the cash distributed to the unitholders with respect to that period.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month (or in some cases for periods shorter than a month) based upon the ownership of our units on the first day of each month (or shorter period), instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month (or in some cases for periods shorter than a month) based upon the ownership of our units on the first day of each month (or shorter period), instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss, or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Unitholders may be subject to state and local taxes and return filing requirements in states and jurisdictions where they do not live as a result of investing in our units.

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 2009, we have done business and owned assets in West Virginia, Virginia, Pennsylvania, 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.

Item 1A. Risk Factors - Continued

Changes to current federal tax laws may affect unitholders' ability to take certain tax deductions.

Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, the ability to take certain operations-related deductions, including deductions for intangible drilling and percentage depletion and deductions for United States production activities. Other proposed changes may affect our ability to remain taxable as a partnership for federal income tax purposes. We are unable to predict whether any changes, or other proposals to such laws, ultimately will be enacted. Any such changes could negatively impact the value of an investment in our units.

The adoption of derivatives legislation by the United States Congress could have an adverse impact on our ability to hedge risks associated with our business.

Several proposals for derivative reform have been developed by committees in the United States House of Representatives and the United States Senate. These proposals are focused on expanding federal regulation surrounding the use of financial derivative instruments, including credit default swaps, commodity derivatives and other over-the-counter derivatives. Among the recommendations included in the proposals are the requirements for centralized clearing or settling of such derivatives as well as the expansion of collateral margin requirements for certain derivative-market participants. Depending on the ultimate form of legislation, our derivatives utilization could be adversely affected with: (i) greater administrative burden; (ii) limitations on the form and use of derivatives; and (iii) expanded collateral margin requirements.

Although it is not possible at this time to predict when the United States Congress may act on derivatives legislation, any laws or regulations that may be adopted that subject us to additional restrictions on our commodity derivative positions could have an adverse effect on our ability to hedge.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

The Company's obligations under its Credit Facility are secured by mortgages on its oil and natural gas properties. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 6 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

There were no matters submitted to a vote of security holders during the three months ended December 31, 2009.

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

Executive Officers of the Company

Name	Age	Position with the Company
Michael C. Linn	58	Executive Chairman of the Board of Directors
Mark E. Ellis	54	President and Chief Executive Officer and Director
Kolja Rockov	39	Executive Vice President and Chief Financial Officer
Charlene A. Ripley	46	Senior Vice President, General Counsel and Corporate Secretary
David B. Rottino	44	Senior Vice President and Chief Accounting Officer
Arden L. Walker, Jr.	50	Senior Vice President and Chief Operating Officer

Michael C. Linn is the Executive Chairman of the Board of Directors of the Company and has served in such capacity since January 2010. He served as Chairman and Chief Executive Officer from December 2007 to January 2010; Chairman, President and Chief Executive Officer from June 2006 to December 2007; and President, Chief Executive Officer and Director of the Company from March 2003 to June 2006. Mr. Linn serves on the National Petroleum Council and American Exploration and Production Council. He serves on the boards of America's Natural Gas Alliance and the Independent Petroleum Association of America ("IPAA"). He is also Chairman of the IPAA Political Action Committee and past Chairman of IPAA. He serves as the Texas Representative for the Legal and Regulatory Affairs Committee of the Interstate Oil and Gas Compact Commission. He previously served as Chairman of the National Gas Council and Director of the Natural Gas Supply Association. He is former President of the Independent Oil and Gas Associations of New York, Pennsylvania and West Virginia. Mr. Linn regularly appears on behalf of the oil and natural gas industry before state and federal agencies, United States Congress and national broadcast media. His civic affiliations include serving on the boards of the Texas Heart Institute, Museum of Fine Arts Houston and Houston Police Foundation. In addition, he is the Chairman of the Texas Children's Hospital Corporate Committee Capital Campaign. He also serves on the Advisory Board of Houston Children's Charity and is a member of the Dean's Executive Advisory Board for the University of Houston C.T. Bauer College of Business. Mr. Linn graduated *cum laude* from Villanova University in 1974 with a BA in Political Science *cum laude* from the University of Baltimore School of Law in 1977. Following graduation, Mr. Linn went on to practice law for the law firm of Ecker, Ecker, Zofer and Rome. In 1980, he became General Counsel for Meridian Exploration, where he ultimately served as President and Chief Executive Officer until its sale in 1999. He served as President of Allegheny Interests, Inc. from 2000 to 2003.

Mark E. Ellis is the President and Chief Executive Officer and a Director of the Company and has served in such capacity since January 2010. From December 2007 to January 2010, Mr. Ellis served as President and Chief Operating Officer and from December 2006 to December 2007, Mr. Ellis served as Executive Vice President and Chief Operating Officer of the Company. Mr. Ellis has more than 30 years of experience in the oil and natural 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, a past board member of the New Mexico Oil & Gas Association and previously served on 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, Houston Museum of Natural Science, the Cynthia Woods Mitchell Pavilion, Industry Board of Petroleum Engineering at Texas A&M University and the Visiting Committee of Petroleum Engineering at the Colorado School of Mines.

Kolja Rockov is the Executive Vice President and Chief Financial Officer. Mr. Rockov has more than 15 years of experience in the oil and natural 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 United States exploration and production sector. Prior to October 2004, Mr. Rockov held various senior positions with RBC Capital Markets and its predecessor companies.

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. Ms. Ripley served as Vice President, General Counsel and Secretary of Anadarko Canada Corporation and its predecessor companies since 1998.

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 more than 15 years of oil and natural 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.

Arden L. Walker, Jr. is the Senior Vice President and Chief Operating Officer of the Company and has served in such capacity since January 2010. Mr. Walker joined the Company in February 2007 as Senior Vice President - Operations and Chief Engineer to oversee its Texas, Oklahoma and California operations, 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. 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.

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 29, 2010, there were approximately 372 unitholders of record.

The following sets forth 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		Cash Distribution Declared Per Unit
	High	Low	
2009:			
October 1 – December 31	$ 28.00	$ 22.18	$ 0.63
July 1 – September 30	$ 23.96	$ 18.66	$ 0.63
April 1 – June 30	$ 20.42	$ 14.77	$ 0.63
January 1 – March 31	$ 16.65	$ 12.95	$ 0.63
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

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.

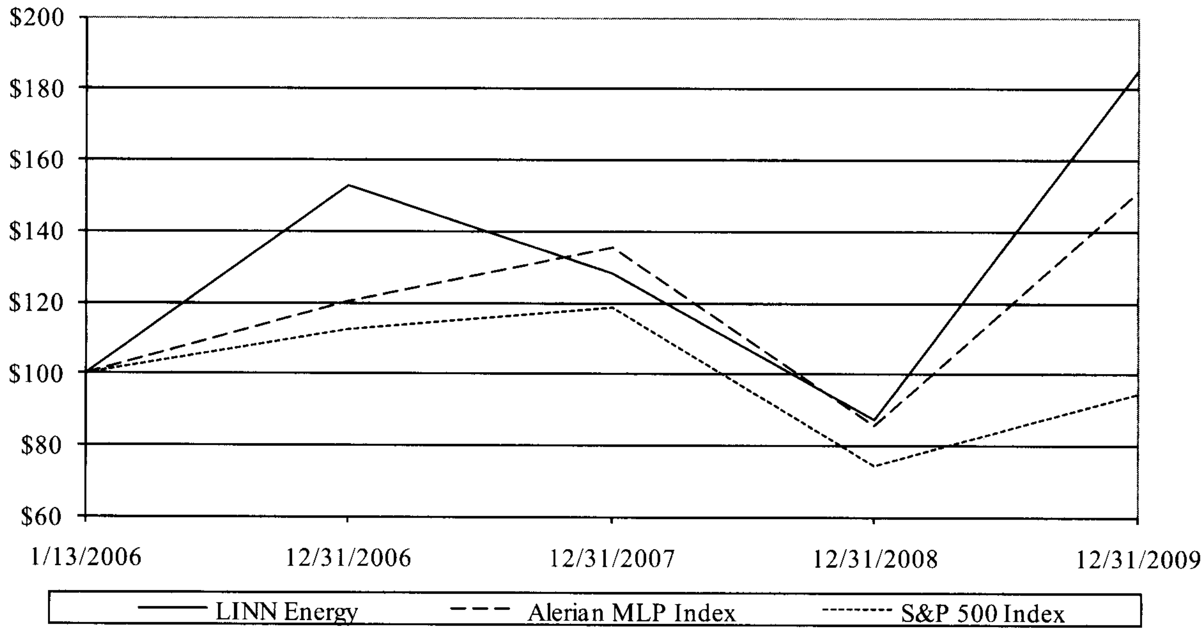
Working capital borrowings are borrowings that will be made under the Company's Credit Facility and in all cases are used solely for working capital purposes or to pay distributions to unitholders.

See 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.

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

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 date 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	December 31, 2009
LINN Energy	$ 100	$ 153	$ 128	$ 87	$ 185
Alerian MLP Index	$ 100	$ 120	$ 136	$ 86	$ 151
S&P 500 Index	$ 100	$ 112	$ 118	$ 75	$ 94

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 Annual Report on 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 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.

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

Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

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 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. The Company did not repurchase any units during the three months ended December 31, 2009. At December 31, 2009, approximately $85.4 million was available for unit repurchase under the program.

Item 6. Selected Financial Data

The selected financial data set forth below should be read in conjunction with 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 continuing operations.

	At or for the Year Ended December 31,				
	2009	2008	2007	2006	2005
	(in thousands, except per unit amounts)				
Statement of operations data:					
Oil, natural gas and natural gas liquid sales	$ 408,219	$ 755,644	$ 255,927	$ 21,372	$ —
Gain (loss) on oil and natural gas derivatives	(141,374)	662,782	(345,537)	103,308	(76,193)
Depreciation, depletion and amortization	201,782	194,093	69,081	4,352	—
Interest expense, net of amounts capitalized	92,701	94,517	38,974	5,909	481
Income (loss) from continuing operations	(295,841)	825,657	(356,194)	69,811	(79,311)
Income (loss) from discontinued operations, net of taxes [1]	(2,351)	173,959	(8,155)	9,374	22,960
Net income (loss)	(298,192)	999,616	(364,349)	79,185	(56,351)
Income (loss) per unit – continuing operations: [2]					
Basic	(2.48)	7.18	(5.17)	2.30	(3.87)
Diluted	(2.48)	7.18	(5.17)	2.28	(3.87)
Income (loss) per unit – discontinued operations: [2]					
Basic	(0.02)	1.52	(0.12)	0.31	1.12
Diluted	(0.02)	1.52	(0.12)	0.31	1.12
Net income (loss) per unit: [2]					
Basic	(2.50)	8.70	(5.29)	2.61	(2.75)
Diluted	(2.50)	8.70	(5.29)	2.59	(2.75)
Distributions declared per unit	2.52	2.52	2.18	1.15	—
Weighted average units outstanding	119,307	114,140	68,916	28,281	20,518
Cash flow data:					
Net cash provided by (used in):					
Operating activities [3]	$ 426,804	$ 179,515	$ (44,814)	$ (6,805)	$ (29,518)
Investing activities	(282,273)	(35,550)	(2,892,420)	(551,631)	(150,898)
Financing activities	(150,968)	(116,738)	2,932,080	553,990	189,269
Balance sheet data:					
Total assets	$ 4,340,256	$ 4,722,020	$ 3,807,703	$ 905,912	$ 280,924
Long-term debt	1,588,831	1,653,568	1,443,830	428,237	207,695
Unitholders' capital (deficit)	2,452,004	2,760,686	2,026,641	450,954	(46,831)

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

(2) Effective January 1, 2009, the Company adopted an accounting standard requiring unvested restricted units to be included in the computation of earnings per unit under the two-class method. The adoption required retrospective adjustment of all prior period earnings per unit data. The impact of the adoption was a reduction to income from continuing operations per unit – diluted and net income per unit – diluted, of $0.05 per unit and $0.02 per unit for the years ended December 31, 2008, and December 31, 2006, respectively. There was no impact for the years ended December 31, 2007, or December 31, 2005.

(3) Includes premiums paid for derivatives of approximately $93.6 million, $129.5 million, $279.3 million, $49.8 million and $1.6 million for the years ended December 31, 2009, December 31, 2008, December 31, 2007, December 31, 2006, and December 31, 2005, respectively.

	At or for the Year Ended December 31,				
	2009	2008	2007	2006	2005
Production data:					
Average daily production – continuing operations:					
Natural gas (MMcf/d)	125	124	51	2	—
Oil (MBbls/d)	9.0	8.6	3.4	0.9	—
NGL (MBbls/d)	6.5	6.2	2.7	—	—
Total (MMcfe/d)	218	212	87	8	—
Average daily production – discontinued operations:					
Total (MMcfe/d)	—	12	24	22	13
Estimated proved reserves – continuing operations: (1)					
Natural gas (Bcf)	774	851	833	77	—
Oil (MMBbls)	102	84	55	30	—
NGL (MMBbls)	54	51	43	—	—
Total (Bcfe)	1,712	1,660	1,419	255	—
Estimated proved reserves – discontinued operations: (1)					
Total (Bcfe)	—	—	197	199	193

(1) In accordance with SEC regulations, reserves at December 31, 2009, were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. In accordance with SEC regulations, reserves for all prior years were estimated using year-end prices.

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 "Consolidated Financial Statements" and "Notes to Consolidated Financial Statements," which are included in this Annual Report on Form 10-K in Item 8. "Financial Statements and Supplementary Data." 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, natural gas and NGL, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, credit and capital market 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 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."

Executive Overview

LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. LINN Energy is an independent oil and natural gas company that began operations in March 2003 and completed its IPO in January 2006. The Company's properties are located in the United States, primarily in the Mid-Continent, California and the Permian Basin.

Proved reserves at December 31, 2009, were 1,712 Bcfe, of which approximately 36% were oil, 45% were natural gas and 19% were NGL. Approximately 71% were classified as proved developed, with a total standardized measure of discounted future net cash flows of $1.72 billion. At December 31, 2009, the Company operated 4,688, or 68%, of its 6,931 gross productive wells and had an average proved reserve-life index of approximately 22 years, based on the December 31, 2009, reserve report and annualized production for the three months ended December 31, 2009.

In January 2010, the Company completed an acquisition of oil and natural gas properties in the Anadarko and Permian Basins for a contract price of $154.5 million. See "Acquisitions" below for additional details. On a pro forma basis, including this acquisition, total proved reserves at December 31, 2009, were 1,785 Bcfe, of which approximately 37% were oil, 44% were natural gas and 19% were NGL. For additional information regarding estimates of reserves, see "Supplemental Oil and Natural Gas Data (Unaudited)" in Item 8. "Financial Statements and Supplementary Data" and see also Item 1. "Business."

From inception through the date of this report, excluding 15 acquisitions comprising the Appalachian Basin properties sold in July 2008, the Company has completed 13 acquisitions of working and royalty interests in oil and natural gas properties and related gathering and pipeline assets. Total acquired proved reserves were approximately 1.8 Tcfe at the time of acquisition at an acquisition cost of approximately $2.15 per Mcfe. The Company finances acquisitions with a combination of funds from equity and debt offerings, bank borrowings and cash generated from operations. See Note 2 for additional details about the Company's acquisitions and divestitures.

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 continuing operations.

Results from continuing operations for the year ended December 31, 2009, included the following:

- oil, natural gas and NGL sales of approximately $408.2 million, compared to $755.6 million in 2008;
- average daily production of 218 MMcfe/d, compared to 212 MMcfe/d in 2008;

- realized gains on commodity derivatives of approximately $450.0 million, compared to realized losses of $72.0 million in 2008;
- adjusted EBITDA of $566.2 million, compared to $514.5 million in 2008;
- adjusted net income of $206.9 million, compared to $174.7 million in 2008;
- capital expenditures, excluding acquisitions, of approximately $149.5 million, compared to $321.3 million in 2008; and
- 73 wells drilled (72 successful), compared to 306 wells drilled (304 successful) in 2008.

Adjusted EBITDA and adjusted net income are non-GAAP financial measures used by management to analyze Company performance. Adjusted EBITDA is a measure used by Company management to evaluate cash flow and the Company's ability to sustain or increase distributions. The most significant reconciling items between net income (loss) and adjusted EBITDA are interest expense and noncash items, including the change in fair value of derivatives and depreciation, depletion and amortization. Adjusted net income is used by Company management to evaluate its operational performance from oil and natural gas properties, prior to derivative gains and losses, impairment of goodwill and long-lived assets and (gain) loss on sale of assets, net. See "Non-GAAP Financial Measures" on page 56 for a reconciliation of each non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Acquisitions

On January 29, 2010, the Company completed the acquisition of certain oil and natural gas properties located in the Anadarko Basin in Oklahoma and Kansas and the Permian Basin in Texas and New Mexico, from Merit for a contract price of $154.5 million. The transaction was financed with borrowings under the Company's Credit Facility. The acquisition provides a strategic addition to the Company's asset portfolio in the Permian Basin and Mid-Continent, and includes approximately 12 MMBoe (73 Bcfe) of proved reserves as of the acquisition date, primarily oil.

On August 31, 2009, and September 30, 2009, the Company completed the acquisitions of certain oil and natural gas properties located in the Permian Basin in Texas and New Mexico from Forest. The Company paid $114.4 million in cash, net of cash received from Forest post-closing, and recorded a receivable from Forest, resulting in total consideration for the acquisitions of approximately $113.7 million. The transactions were financed with borrowings under the Company's Credit Facility. The acquisitions represent a strategic entry into the Permian Basin for the Company, and include approximately 10 MMBoe (62 Bcfe) of proved reserves, primarily oil.

Commodity Derivatives

In February 2010, the Company entered into fixed price oil swaps on an additional 5,250 Bbls per day at a price of $100.00 per Bbl for the years ending December 31, 2012, and December 31, 2013, bringing the Company's total such fixed price oil swaps to swaps on 7,250 Bbls per day as presented in the table below. The Company has derivative contracts that extend the swaps for each of the years ending December 31, 2014, December 31, 2015, and December 31, 2016, if the counterparties determine that the strike prices are in-the-money on a designated date in each respective preceding year. The extension for each year is exercisable without respect to the other years.

The following table summarizes open positions as of February 24, 2010, and represents, as of such date, derivatives in place through December 31, 2013, on annual production volumes:

	February 24 – December 31, 2010	Year 2011	Year 2012	Year 2013
Natural gas positions:				
Fixed price swaps:				
Hedged volume (MMMBtu)	32,971	31,901	—	—
Average price ($/MMBtu)	$ 8.90	$ 9.50	$ —	$ —
Puts:				
Hedged volume (MMMBtu)	5,800	6,960	—	—
Average price ($/MMBtu)	$ 8.50	$ 9.50	$ —	$ —
PEPL puts: (1)				
Hedged volume (MMMBtu)	8,862	13,259	—	—
Average price ($/MMBtu)	$ 7.85	$ 8.50	$ —	$ —
Total:				
Hedged volume (MMMBtu)	47,633	52,120	—	—
Average price ($/MMBtu)	$ 8.66	$ 9.25	$ —	$ —
Oil positions:				
Fixed price swaps: (2)				
Hedged volume (MBbls)	1,971	2,073	2,654	2,646
Average price ($/Bbl)	$ 90.00	$ 90.00	$ 100.00	$ 100.00
Puts: (3)				
Hedged volume (MBbls)	2,062	2,352	—	—
Average price ($/Bbl)	$ 110.00	$ 75.00	$ —	$ —
Collars:				
Hedged volume (MBbls)	229	276	—	—
Average floor price ($/Bbl)	$ 90.00	$ 90.00	$ —	$ —
Average ceiling price ($/Bbl)	$ 112.00	$ 112.25	$ —	$ —
Total:				
Hedged volume (MBbls)	4,262	4,701	2,654	2,646
Average price ($/Bbl)	$ 99.68	$ 82.50	$ 100.00	$ 100.00
Natural gas basis differential positions:				
PEPL basis swaps: (1)				
Hedged volume (MMMBtu)	35,972	35,541	34,066	31,700
Hedged differential ($/MMBtu)	$ (0.97)	$ (0.96)	$ (0.95)	$ (1.01)

(1) Settle on the PEPL spot price of natural gas to hedge basis differential associated with natural gas production in the Mid-Continent Deep and Mid-Continent Shallow regions.

(2) As presented in the table above, the Company has outstanding fixed price oil swaps on 7,250 Bbls per day at a price of $100.00 per Bbl for the years ending December 31, 2012, and December 31, 2013. The Company has derivative contracts that extend the swaps for each of the years ending December 31, 2014, December 31, 2015, and December 31, 2016, if the counterparties determine that the strike prices are in-the-money on a designated date in each respective preceding year. The extension for each year is exercisable without respect to the other years.

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

Liquidity and Debt

During 2009, the Company took several steps to strengthen its liquidity and extend its weighted average debt maturities. In April 2009, the Company amended and restated its existing Credit Facility to extend the maturity to August 2012, and at January 29, 2010, the Company had $422.0 million in available borrowing capacity under the Credit Facility. In addition, in May 2009, the Company issued $250.0 million in aggregate principal of 11.75% senior notes due 2017 and used the net proceeds of approximately $230.8 million to reduce indebtedness under its Credit Facility. In May 2009 and October 2009, the Company completed public offerings of units for aggregate net proceeds of approximately $279.3 million, which was used to reduce indebtedness under the Credit Facility.

The Company hedges a significant portion of its forecasted production to reduce exposure to fluctuations in the prices of oil, natural gas and NGL and provide long-term cash flow predictability to pay distributions, service debt and manage its business. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. The Company has derivative contracts in place for 2010 and 2011 at average prices of $99.68 per Bbl and $82.50 per Bbl for oil and $8.66 per MMBtu and $9.25 per MMBtu for natural gas, respectively. Additionally, the Company has derivative contracts in place covering substantially all of its exposure to the Mid-Continent natural gas basis differential.

Operating Regions

Inclusive of the properties acquired from Merit in January 2010 (see "Acquisitions" above), the Company's properties are located in four regions in the United States:

- Mid-Continent Deep, which includes the Texas Panhandle Deep Granite Wash formation and deep formations in Oklahoma and Kansas;
- Mid-Continent Shallow, which includes the Texas Panhandle Brown Dolomite formation and shallow formations in Oklahoma, Louisiana and Illinois;
- California, which includes the Brea Olinda Field of the Los Angeles Basin; and
- Permian Basin, which includes areas in West Texas and Southeast New Mexico.

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 and Kansas , which produce at depths of more than 8,000 feet. Mid-Continent Deep proved reserves represented approximately 47% of total proved reserves at December 31, 2009, of which 71% were classified as proved developed reserves. This region produced 135 MMcfe/d, or 62%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $99.3 million to drill in this region. During 2010, the Company anticipates spending approximately 60% 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 and properties in Oklahoma, Louisiana and Illinois, which produce at depths of less than 8,000 feet. Mid-Continent Shallow proved reserves represented approximately 38% of total proved reserves at December 31, 2009, of which 66% were classified as proved developed reserves. This region produced 67 MMcfe/d, or 31%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $21.0 million to drill in this region. During 2010, the Company anticipates spending approximately 20% of its total capital budget for development activities in the Mid-Continent Shallow region.

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

California

The California region consists of the Brea Olinda Field of the Los Angeles Basin. The Brea Olinda Field was discovered in 1880 and produces from the shallow Pliocene formation to the deeper Miocene formation at depths of 1,000 feet to 7,500 feet. California proved reserves represented approximately 11% of total proved reserves at December 31, 2009, of which 94% were classified as proved developed reserves. This region produced 14 MMcfe/d, or 6%, of the Company's 2009 average daily production.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the United States. The Company's properties are located in West Texas and Southeast New Mexico and produce at depths ranging from 2,000 feet to 9,000 feet. Permian Basin proved reserves represented approximately 4% of total proved reserves at December 31, 2009, of which 53% were classified as proved developed reserves. The properties that comprise this region as of December 31, 2009, were acquired in the third quarter of 2009 (see "Acquisitions" above). This region produced 2 MMcfe/d, or 1%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $0.1 million to drill in this region. During 2010, the Company anticipates spending approximately 20% of its total capital budget for development activities in the Permian Basin region.

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

Results of Operations – Continuing Operations

Year Ended December 31, 2009, Compared to Year Ended December 31, 2008

	Year Ended December 31,		
	2009	2008	Variance
	(in thousands)		
Revenues and other:			
Natural gas sales	$ 160,470	$ 334,214	$ (173,744)
Oil sales	181,619	291,132	(109,513)
NGL sales	66,130	130,298	(64,168)
Total oil, natural gas and NGL sales	408,219	755,644	(347,425)
Gain (loss) on oil and natural gas derivatives [(1)]	(141,374)	662,782	(804,156)
Natural gas marketing revenues	4,380	12,846	(8,466)
Other revenues	1,924	3,759	(1,835)
	$ 273,149	$ 1,435,031	$(1,161,882)
Expenses:			
Lease operating expenses	$ 132,647	$ 115,402	$ 17,245
Transportation expenses	18,202	17,597	605
Natural gas marketing expenses	2,154	11,070	(8,916)
General and administrative expenses [(2)]	86,134	77,391	8,743
Exploration costs	7,169	7,603	(434)
Bad debt expenses	401	1,436	(1,035)
Depreciation, depletion and amortization	201,782	194,093	7,689
Impairment of goodwill and long-lived assets	—	50,505	(50,505)
Taxes, other than income taxes	27,605	61,435	(33,830)
(Gain) loss on sale of assets and other, net	(24,598)	(98,763)	74,165
	$ 451,496	$ 437,769	$ 13,727
Other income and (expenses)	$ (121,715)	$ (168,893)	$ 47,178
Income (loss) from continuing operations before income taxes	$ (300,062)	$ 828,369	$(1,128,431)
Adjusted EBITDA [(3)]	$ 566,235	$ 514,487	$ 51,748
Adjusted net income [(3)]	$ 206,922	$ 174,663	$ 32,259

(1) During the year ended December 31, 2009, the Company canceled (before the contract settlement date) derivative contracts on estimated future oil and natural gas production resulting in realized net gains of approximately $49.0 million, primarily associated with the Company's commodity derivative repositioning in July 2009 (see Note 7). During the year ended December 31, 2008, the Company canceled (before the contract settlement date) derivative contracts on estimated future natural 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.

(2) General and administrative expenses for the years ended December 31, 2009, and December 31, 2008, include approximately $14.7 million and $14.6 million, respectively, of noncash unit-based compensation expenses.

(3) This is a non-GAAP measure used by management to analyze Company performance. See "Non-GAAP Financial Measures" on page 56 for a reconciliation of the non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

	Year Ended December 31, 2009	2008	Variance
Average daily production:			
Natural gas (MMcf/d)	125	124	1%
Oil (MBbls/d)	9.0	8.6	5%
NGL (MBbls/d)	6.5	6.2	5%
Total (MMcfe/d)	218	212	3%
Weighted average prices (hedged): [(1)]			
Natural gas (Mcf)	$ 8.27	$ 8.42	(2)%
Oil (Bbl)	$ 110.94	$ 80.92	37%
NGL (Bbl)	$ 28.04	$ 57.86	(52)%
Weighted average prices (unhedged): [(2)]			
Natural gas (Mcf)	$ 3.51	$ 7.39	(53)%
Oil (Bbl)	$ 55.25	$ 92.78	(40)%
NGL (Bbl)	$ 28.04	$ 57.86	(52)%
Average NYMEX prices:			
Natural gas (MMBtu)	$ 3.99	$ 9.04	(56)%
Oil (Bbl)	$ 61.94	$ 99.65	(38)%
Costs per Mcfe of production:			
Lease operating expenses	$ 1.67	$ 1.49	12%
Transportation expenses	$ 0.23	$ 0.23	—
General and administrative expenses [(3)]	$ 1.08	$ 1.00	8%
Depreciation, depletion and amortization	$ 2.53	$ 2.50	1%
Taxes, other than income taxes	$ 0.35	$ 0.79	(56)%

(1) Includes the effect of realized gains on derivatives of approximately $401.0 million (excluding $49.0 million realized net gains on canceled contracts) and $9.4 million (excluding $81.4 million realized losses on canceled contracts) for the years ended December 31, 2009, and December 31, 2008, respectively. The Company utilizes oil puts to hedge revenues associated with its NGL production; therefore, all realized gains (losses) on oil derivative contracts are included in weighted average oil prices, rather than weighted average NGL prices.

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

(3) General and administrative expenses for the years ended December 31, 2009, and December 31, 2008, include approximately $14.7 million and $14.6 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2009, and December 31, 2008, were $0.90 per Mcfe and $0.81 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company's performance.

Revenues and Other

Oil, Natural Gas and NGL Sales
Oil, natural gas and NGL sales decreased by approximately $347.4 million, or 46%, to approximately $408.2 million for the year ended December 31, 2009, from $755.6 million for the year ended December 31, 2008, due to lower commodity prices. Lower oil, natural gas and NGL prices resulted in a decrease in revenues of approximately $123.3, $177.6 million and $70.3 million, respectively.

Average daily production increased to 218 MMcfe/d during the year ended December 31, 2009, from 212 MMcfe/d during the year ended December 31, 2008. Volume increases during the year ended December 31, 2009, resulted in an increase in total oil, natural gas and NGL revenues of approximately $23.8 million compared to the year ended December 31, 2008.

The following sets forth average daily production by region:

	Year Ended December 31,		Variance	
	2009	2008		
Average daily production (MMcfe/d):				
Mid-Continent Deep	135	136	(1)	(1)%
Mid-Continent Shallow	67	63	4	6%
California	14	13	1	8%
Permian Basin	2	—	2	—
	218	212	6	3%

The 1% decrease in average daily production in the Mid-Continent Deep region primarily reflects the Company's sale of assets in Oklahoma in August 2008 (see Note 2), its decision to suspend completions on recent wells drilled in the Granite Wash and shut-in production on certain wells. The 6% increase in average daily production in the Mid-Continent Shallow region reflects results of the Company's drilling and optimization programs, partially offset by natural declines. The California region consists of a low-decline asset base and continues to produce at levels consistent with the prior year. The Permian Basin properties were acquired in the third quarter of 2009 (see Note 2).

Gain (Loss) on Oil and Natural Gas Derivatives
The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk," Note 7 and Note 8 for additional information about commodity derivatives. During the year ended December 31, 2009, the Company had commodity derivative contracts for approximately 113% of its natural gas production and 80% of its oil and NGL production, which resulted in realized gains of approximately $450.0 million (including realized net gains on canceled contracts of approximately $49.0 million). During the year ended December 31, 2009, the Company repositioned its commodity derivative portfolio to help protect against sustained weakness in commodity prices. The Company canceled oil and natural gas derivative contracts for years 2012 through 2014 and used the realized net gains of approximately $44.8 million, along with an incremental premium payment of approximately $48.8 million, to raise prices for oil and natural gas derivative contracts in years 2010 and 2011. During the year ended December 31, 2008, the Company recorded realized losses of approximately $72.0 million (including realized losses on canceled contracts of approximately $81.4 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 2009, expected future oil and natural gas prices increased, which resulted in unrealized losses on derivatives of approximately $591.4 million for the year ended December 31, 2009. During the second half of 2008, expected future oil and natural gas prices decreased, which resulted in unrealized gains on derivatives of approximately $734.7 million for the year ended December 31, 2008. For information about the Company's credit risk related to derivative contracts see "Counterparty Credit Risk" in "Liquidity and Capital Resources" 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 $17.2 million, or 15%, to $132.6 million for the year ended December 31, 2009, from $115.4 million for the year ended December 31, 2008. Lease operating expenses per Mcfe also increased, to $1.67 per Mcfe for the year ended December 31, 2009, from $1.49 per Mcfe for the year ended December 31, 2008. Lease operating expenses increased primarily due to costs associated with properties acquired in the first quarter of 2008 in the Mid-Continent Shallow region and the third quarter of 2009 in the Permian Basin region (see Note 2). Lease operating expenses are generally higher for oil properties than for natural gas properties. Materials and service cost increases across all operating regions and higher chemical and treating costs associated with certain wells drilled in late 2008 also contributed to the increase.

Transportation Expenses
Transportation expenses increased by approximately $0.6 million, or 3%, to $18.2 million for the year ended December 31, 2009, from $17.6 million for the year ended December 31, 2008, primarily due to increased production volumes.

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. General and administrative expenses increased by approximately $8.7 million, or 11%, to $86.1 million for the year ended December 31, 2009, from $77.4 million for the year ended December 31, 2008. General and administrative expenses per Mcfe also increased, to $1.08 per Mcfe for the year ended December 31, 2009, from $1.00 per Mcfe for the year ended December 31, 2008. The increase was primarily due to an increase in salaries and benefits expense of approximately $7.3 million, driven primarily by an increase in employee headcount.

Exploration Costs
Exploration costs decreased by approximately $0.4 million, or 5%, to $7.2 million for the year ended December 31, 2009, from $7.6 million for the year ended December 31, 2008. The decrease was primarily due to a decrease in 3-D seismic and data library expense of approximately $2.2 million, partially offset by an increase in impairment expense on unproved properties of approximately $1.8 million.

Depreciation, Depletion and Amortization
Depreciation, depletion and amortization increased by approximately $7.7 million, or 4%, to $201.8 million for the year ended December 31, 2009, from $194.1 million for the year ended December 31, 2008. Higher total production levels were the main reason for the increase. Depreciation, depletion and amortization per Mcfe increased to $2.53 per Mcfe for the year ended December 31, 2009, from $2.50 per Mcfe for the year ended December 31, 2008.

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 was associated with impairment of goodwill and approximately $30.2 million was associated with impairment of proved oil and natural gas properties. The Company recorded no impairment for the year ended December 31, 2009. See Note 1 and "Critical Accounting Policies and Estimates" below for additional information.

Taxes, Other Than Income Taxes
Taxes, other than income taxes, which consist primarily of production and ad valorem taxes, decreased by approximately $33.8 million, or 55%, to $27.6 million for the year ended December 31, 2009, from $61.4 million for the year ended December 31, 2008. Production taxes, which are a function of revenues generated from production, decreased by approximately $30.2 million compared to the year ended December 31, 2008, primarily due to lower commodity prices. Tax credits related to incentive programs for deep wells and marketing deductions

also contributed to the decrease. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, decreased slightly compared to the year ended December 31, 2008.

(Gain) Loss on Sale of Assets and Other, Net
The Company recorded a gain of approximately $25.4 million from the sale of Woodford Shale assets during the year ended December 31, 2009, (see Note 2).

Other Income and (Expenses)

	Year Ended December 31, 2009	Year Ended December 31, 2008	Variance
	(in thousands)		
Interest expense, net of amounts capitalized	$ (92,701)	$ (94,517)	$ 1,816
Realized loss on interest rate swaps	(42,941)	(16,036)	(26,905)
Unrealized gain (loss) on interest rate swaps	16,588	(50,638)	67,226
Other, net	(2,661)	(7,702)	5,041
	$ (121,715)	$ (168,893)	$ 47,178

Other income and (expenses) decreased by approximately $47.2 million during the year ended December 31, 2009, compared to the year ended December 31, 2008. Interest expense decreased, driven by lower interest rates on the Credit Facility due to lower LIBOR rates. The unrealized mark-to-market change on interest rate swaps was a positive impact, as the forward rate curve decreased less during the year ended December 31, 2009, than it did during the year ended December 31, 2008. This was partially offset by increased realized losses on interest rate swaps during the year ended December 31, 2009, compared to the year ended December 31, 2008. In addition, the Company wrote off deferred financing fees of approximately $6.7 million during the year ended December 31, 2008.

Income Tax Benefit (Expense)

The Company is a limited liability company 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 passed through to unitholders. 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 federal and state income taxes. The Company recognized income tax benefit of approximately $4.2 million and income tax expense of approximately $2.7 million for the years ended December 31, 2009, and December 31, 2008, respectively. Income tax benefit for the year ended December 31, 2009, is primarily due to a release of the valuation allowance on a significant portion of deferred tax assets. Income tax expense for the year ended December 31, 2008, primarily represents Texas margin tax expense.

Income (Loss) From Continuing Operations

Income (loss) from continuing operations was loss of approximately $295.8 million for the year ended December 31, 2009, and income of approximately $825.7 million for the year ended December 31, 2008, due to lower oil, natural gas and NGL revenues as a result of lower commodity prices during the year ended December 31, 2009, combined with the impact of unrealized losses on commodity derivatives.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased by approximately $51.7 million, or 10%, to $566.2 million for the year ended December 31, 2009, from $514.5 million for the year ended December 31, 2008, primarily due to increased realized gains on commodity derivatives, offset by lower oil, natural gas and NGL revenues due to lower commodity prices. See "Non-GAAP Financial Measures" on page 56 for a reconciliation of adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP.

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

	Year Ended December 31, 2008	Year Ended December 31, 2007	Variance
	(in thousands)		
Revenues and other:			
Natural 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, natural gas and NGL sales	755,644	255,927	499,717
Gain (loss) on oil and natural gas derivatives (1)	662,782	(345,537)	1,008,319
Natural 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
Natural gas marketing expenses	11,070	9,100	1,970
General and administrative expenses (2)	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 and other, 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
Adjusted EBITDA (3)	$ 514,487	$ 257,732	$ 256,755
Adjusted net income (3)	$ 174,663	$ 57,908	$ 116,755

(1) During the year ended December 31, 2008, the Company canceled (before the contract settlement date) derivative contracts on estimated future natural 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.

(2) General and administrative expenses for the years ended December 31, 2008, and December 31, 2007, include approximately $14.6 million and $13.5 million, respectively, of noncash unit-based compensation expenses.

(3) This is a non-GAAP measure used by management to analyze Company performance. See "Non-GAAP Financial Measures" on page 56 for a reconciliation of the non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

	Year Ended December 31, 2008	Year Ended December 31, 2007	Variance
Average daily production:			
Natural gas (MMcf/d)	124	51	143%
Oil (MBbls/d)	8.6	3.4	153%
NGL (MBbls/d)	6.2	2.7	130%
Total (MMcfe/d)	212	87	144%
Weighted average prices (hedged): [(1)]			
Natural 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)]			
Natural gas (Mcf)	$ 7.39	$ 6.39	16%
Oil (Bbl)	$ 92.78	$ 66.44	40%
NGL (Bbl)	$ 57.86	$ 55.51	4%
Average NYMEX prices:			
Natural 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%

(1) Includes the effect of realized gains on derivatives of approximately $9.4 million (excluding $81.4 million losses on canceled contracts) and $37.3 million for the years ended December 31, 2008, and December 31, 2007, respectively. The Company utilizes oil puts to hedge revenues associated with its NGL production; therefore, all realized gains (losses) on oil derivative contracts are included in weighted average oil prices, rather than weighted average NGL prices.

(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 December 31, 2007, include approximately $14.6 million and $13.5 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2008, and December 31, 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.

Revenues and Other

Oil, Natural Gas and NGL Sales

Oil, natural 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. Higher oil, natural gas and NGL prices resulted in an increase in revenues of approximately $82.6 million, $45.5 million and $5.3 million, respectively.

Average daily production increased to 212 MMcfe/d during the year ended December 31, 2008, from 87 MMcfe/d during the year ended December 31, 2007. Volume increases during the year ended December 31, 2008, resulted in an increase in total oil, natural gas and NGL revenues of approximately $366.3 million compared to the year ended December 31, 2007.

The following sets forth average daily production by region:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Variance	
Average daily production (MMcfe/d):				
Mid-Continent Deep	136	47	89	189%
Mid-Continent Shallow	63	28	35	125%
California	13	12	1	8%
	212	87	125	144%

The 189% increase in average daily production in the Mid-Continent Deep region is primarily due to the Company's acquisition of properties in August 2007, which contributed approximately 126 MMcfe per day during 2008. The 125% increase in average daily production in the Mid-Continent Shallow region is primarily due to the Company's acquisition of properties in January 2008, which contributed approximately 24 MMcfe per day during 2008. The California region consists of a low-decline asset base and continues to produce at levels consistent with the prior year.

Gain (Loss) on Oil and Natural Gas Derivatives

The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. See Note 7 and Note 8 for additional information about commodity derivatives. During the year ended December 31, 2008, the Company had commodity derivative contracts for approximately 112% of its natural gas production and 82% of its oil and NGL production, which resulted in realized losses of approximately $72.0 million (including realized losses on canceled contracts of approximately $81.4 million). During the year ended December 31, 2008, the Company canceled (before the contract settlement date) derivative contracts on estimated future natural 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 natural 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 natural gas prices increased, which resulted in unrealized losses on derivatives of approximately $382.8 million for the year ended December 31, 2007. For information about the Company's credit risk related to derivative contracts see "Counterparty Credit Risk" in "Liquidity and Capital Resources" 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 per Mcfe also increased, to $1.49 per Mcfe for the year ended December 31, 2008, from $1.31 per Mcfe 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.

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. 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 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 August 2007. 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.

Although total general and administrative expenses increased, 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.

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 impairment expense on unproved 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 for bankruptcy.

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 2007 and 2008, 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 properties acquired in the Mid-Continent Deep region in August 2007, as compared to the Company's other 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 was associated with impairment of goodwill and approximately $30.2 million was associated with impairment of proved oil and natural gas properties. See Note 1 and "Critical Accounting Policies and Estimates" below for additional information.

Taxes, Other Than Income Taxes
Taxes, other than income taxes, which consist 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 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 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 and Other, Net
The Company recorded a gain of approximately $99.0 million from the sale of Woodford Shale assets during the year ended December 31, 2008, (see Note 2).

Other Income and (Expenses)

	Year Ended December 31, 2008	Year Ended December 31, 2007	Variance
		(in thousands)	
Interest expense, net of amounts capitalized	$ (94,517)	$ (38,974)	$ (55,543)
Realized gain (loss) on interest rate swaps	(16,036)	1,467	(17,503)
Unrealized loss on interest rate swaps	(50,638)	(29,548)	(21,090)
Other, net	(7,702)	(3,822)	(3,880)
	$ (168,893)	$ (70,877)	$ (98,016)

Other income and (expenses) increased by approximately $98.0 million, 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 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 December 31, 2007, respectively.

Income Tax Expense

The Company is a limited liability company 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 passed through to unitholders. 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 federal and state income taxes. Income tax expense was approximately $2.7 million and $4.8 million for the years ended December 31, 2008, and December 31, 2007, respectively. Income tax expense for the year ended December 31, 2008, primarily represents Texas margin tax expense. 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.

Income (Loss) From Continuing Operations

Income (loss) from continuing operations was income of approximately $825.7 million for the year ended December 31, 2008, and loss of approximately $356.2 million for the year ended December 31, 2007, due to increased production revenues during the year ended December 31, 2008, resulting from the Company's acquisition of properties in August 2007 and January 2008, and to higher oil, natural gas and NGL prices.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased by approximately $256.8 million, or 100%, to $514.5 million for the year ended December 31, 2008, from $257.7 million for the year ended December 31, 2007, primarily due to increased production revenues resulting from the Company's acquisition of properties in August 2007 and January 2008, and to higher oil, natural gas and NGL prices. See "Non-GAAP Financial Measures" on page 56 for a reconciliation of adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Reserve Replacement Metrics

The Company calculates two primary reserve metrics: (i) reserve replacement cost and (ii) reserve replacement ratio, to measure its ability to establish a long-term trend of adding reserves at a reasonable cost. The reserve replacement cost calculation provides an assessment of the cost of adding reserves that is ultimately included in depreciation, depletion and amortization expense. The reserve replacement ratio is an indicator of the Company's ability to replenish annual production volumes and grow reserves. The metrics are calculated as follows:

$$\text{Reserve replacement cost per Mcfe} = \frac{\text{Oil and natural gas capital costs expended}^{(1)}}{\text{Sum of reserve additions}^{(2)}}$$

$$\text{Reserve replacement ratio} = \frac{\text{Sum of reserve additions}^{(2)}}{\text{Annual production}}$$

(1) Oil and natural gas capital costs expended include the costs of property acquisition, exploration and development activities conducted to add reserves and exclude asset retirement obligation costs. The Company expects to incur development costs in the future for proved undeveloped reserves; such future costs are excluded from costs expended and are not considered in the reserve replacement metrics presented herein.

(2) Reserve additions include proved reserves (developed and undeveloped) and reflect reserve revisions for prices and performance, extensions, discoveries and other additions and acquisitions and do not include unproved reserve quantities.

The reserve replacement metrics are presented separately, both: (i) including and excluding the impact of price revisions on reserves, to demonstrate the effectiveness of the Company's drilling program exclusive of economic factors (such as price) outside of its control and (ii) including and excluding acquisitions, to demonstrate the Company's ability to add reserves through its drilling program and through acquisitions. Reserve replacement cost and reserve replacement ratio are non-GAAP financial measures. The methods used by the Company to calculate these measures may differ from methods used by other companies to compute similar measures. As a result, the Company's measures may not be comparable to similar measures provided by other companies. The Company believes that providing such measures is useful in evaluating the cost to add proved reserves; however, these measures should not be considered in isolation or as a substitute for GAAP measures. The reserve replacement cost per Mcfe and reserve replacement ratio are statistical indicators that have limitations, including their predictive and comparative value. The reserve replacement ratio is limited because it may vary widely based on the extent and timing of new discoveries, project sanctioning and property acquisitions. In addition, since the reserve replacement ratio does not consider the development cost or timing of future production of new reserves, it should not be used as a measure of value creation.

The following presents reserve replacement cost and reserve replacement ratio from continuing operations, including and excluding the effect of price revisions on reserves:

	Including Price Revisions			Excluding Price Revisions		
	Year Ended December 31,			Year Ended December 31,		
	2009	2008	2007	2009	2008	2007
Costs per Mcfe of production:						
Reserve replacement cost, including acquisitions	$ 1.96	$ 2.44	$ 2.23	$ 1.71	$ 1.53	$ 2.38
Reserve replacement cost, excluding acquisitions (finding and development cost)	$ 2.03	NM [(1)]	$ 1.16	$ 1.59	$ 1.44	$ 2.74
Percentage of production:						
Reserve replacement ratio, including acquisitions	165%	475%	3,745%	189%	756%	3,521%
Reserve replacement ratio, excluding acquisitions	88%	NM [(1)]	389%	112%	282%	165%

(1) Not meaningful due to the impact of a significant decrease in year-end commodity prices, primarily oil, at December 31, 2008, compared to December 31, 2007, which offset reserve additions.

Amounts used in these calculations reflect continuing operations only and are derived directly from the table presented in "Supplemental Oil and Natural Gas Data (Unaudited)" in Item 8. "Financial Statements and Supplementary Data." The following provides a reconciliation of oil and natural gas capital costs used in these calculations to its most directly comparable financial measure calculated and presented in accordance with GAAP:

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Costs incurred in oil and natural gas property acquisition, exploration and development – continuing operations	$ 258,105	$ 900,256	$ 2,674,439
Less:			
Asset retirement obligation costs	(371)	(680)	(3,868)
Property acquisition costs	(115,929)	(584,630)	(2,525,772)
Oil and natural gas capital costs expended, excluding acquisitions – continuing operations	$ 141,805	$ 314,946	$ 144,799

Liquidity and Capital Resources

The Company utilizes funds from equity and debt offerings, bank borrowings and cash generated from operations for capital resources and liquidity. To date, the primary use of capital has been for the acquisition and development of oil and natural gas properties. For the year ended December 31, 2009, the Company's capital expenditures, excluding acquisitions, were approximately $149.5 million. For 2010, the Company estimates its capital expenditures, excluding acquisitions, will be between $150.0 million and $175.0 million. This estimate is under continuous review and is subject to ongoing adjustment. The Company expects to fund these capital expenditures with cash flow from operations.

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 other borrowings impose certain restrictions on the Company's ability to obtain additional debt financing.

During 2009, the Company took several steps to strengthen its liquidity and extend its weighted average debt maturities. In April 2009, the Company amended and restated its existing Credit Facility to extend the maturity to August 2012, and at January 29, 2010, the Company had $422.0 million in available borrowing capacity under the Credit Facility. In addition, in May 2009, the Company issued $250.0 million in aggregate principal of 11.75% senior notes due 2017 and used the net proceeds of approximately $230.8 million to reduce indebtedness under its Credit Facility. In May 2009 and October 2009, the Company completed public offerings of units for aggregate net proceeds of approximately $279.3 million, which were used to reduce indebtedness under the Credit Facility. Based upon current expectations the Company believes liquidity and capital resources will be sufficient for the conduct of its business and operations.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Year Ended December 31, 2009	2008	2007
		(in thousands)	
Net cash:			
Provided by (used in) operating activities [(1)]	$ 426,804	$ 179,515	$ (44,814)
Used in investing activities	(282,273)	(35,550)	(2,892,420)
Provided by (used in) financing activities	(150,968)	(116,738)	2,932,080
Net increase (decrease) in cash and cash equivalents	$ (6,437)	$ 27,227	$ (5,154)

(1) The years ended December 31, 2009, December 31, 2008, and December 31, 2007, include premiums paid for derivatives of approximately $93.6 million, $129.5 million and $279.3 million, respectively.

Operating Activities

Cash provided by operating activities for the year ended December 31, 2009, was approximately $426.8 million, compared to $179.5 million for the year ended December 31, 2008. The increase was primarily due to higher realized gains from oil and natural gas derivatives, offset by reduced revenues associated with lower commodity prices in 2009.

In comparison, cash used in operating activities was $44.8 million for the year ended December 31, 2007. The use of cash for operating activities was impacted by premiums paid for commodity derivatives of approximately $279.3 million during the year ended December 31, 2007, compared to $129.5 million during the year ended December 31, 2008. These commodity derivatives were utilized by the Company to achieve a more predictable cash flow by reducing exposure to price fluctuations and were funded through the Company's Credit Facility.

Premiums paid during 2009, 2008 and 2007, noted in the table above, were for commodity derivative contracts that hedge future production. These derivative contracts provide the Company long-term cash flow predictability to manage its business, service debt and pay distributions and are primarily funded through the Company's Credit Facility. The amount of derivative contracts the Company enters into in the future will be directly related to expected future production. See Note 7 and Note 8 for additional details about commodity derivatives.

Investing Activities

The following provides a comparative summary of cash flow from investing activities:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Cash flow from investing activities:			
Acquisition of oil and natural gas properties	$ (130,735)	$ (593,412)	$ (2,677,575)
Capital expenditures	(178,242)	(339,724)	(219,383)
Proceeds from sale of properties and equipment	26,704	897,586	4,538
	$ (282,273)	$ (35,550)	$ (2,892,420)

The primary use of cash in investing activities is for capital spending, which is offset by proceeds from asset sales. Cash used in investing activities was approximately $282.3 million for the year ended December 31, 2009, compared to $35.6 million for the year ended December 31, 2008. Cash used in investing activities for the year ended December 31, 2009, includes approximately $114.4 million for the acquisition of Permian Basin properties in the Mid-Continent Shallow region (see Note 2).

Cash used in investing activities for the year ended December 31, 2008, includes approximately $510.6 million for the acquisition of properties in the Mid-Continent Shallow region and proceeds from asset sales totaling approximately $897.6 million, primarily from the sale of properties in the Appalachian Basin, the Verden area in Oklahoma, and the Woodford Shale interval in Oklahoma (see Note 2). In comparison, cash used in investing activities was approximately $2.89 billion for the year ended December 31, 2007, and includes approximately $2.03 billion for the acquisition of properties in the Mid-Continent Deep region and $555.5 million for the acquisition of properties in the Mid-Continent Shallow region.

Financing Activities

Cash used in financing activities was approximately $151.0 million for the year ended December 31, 2009, compared to $116.7 million for the year ended December 31, 2008. The change in financing cash flow was primarily due to increased operating cash flow and decreased acquisition and development activity during 2009, which resulted in lower net borrowings compared to 2008. In comparison, cash provided by financing activities was $2.93 billion for the year ended December 31, 2007, primarily due to $2.09 billion received from the sale of units in private placement transactions (see Note 3). The following provides a comparative summary of proceeds from borrowings and repayments of debt:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Proceeds from borrowings:			
Credit facility	$ 401,500	$ 809,000	$ 1,298,000
Senior notes	237,703	250,000	—
Term loan	—	400,000	—
	$ 639,203	$ 1,459,000	$ 1,298,000
Repayments of debt:			
Credit facility	$ (704,893)	$ (848,608)	$ (280,750)
Term loan	—	(400,000)	—
Notes payable	—	(1,564)	(2,358)
	$ (704,893)	$ (1,250,172)	$ (283,108)

Debt

On April 28, 2009, the Company entered into an amended and restated Credit Facility, with an initial borrowing base of $1.75 billion and a maturity of August 2012, which amended and restated the Company's existing credit facility, which had a maturity of August 2010. The terms of the Credit Facility required that, upon the issuance of the 2017 Notes in May 2009 (see below) and cancellation of certain commodity derivatives in July 2009 (see Note 7), the borrowing base be decreased by approximately $62.5 million and $45.0 million, respectively, to $1.64 billion, which remained the borrowing base at January 29, 2010. At January 29, 2010, available borrowing capacity was $422.0 million, which includes a $5.5 million reduction in availability for outstanding letters of credit.

In May 2009, the Company issued $250.0 million in aggregate principal amount of the Company's 11.75% senior notes due 2017. The Company used the net proceeds of approximately $230.8 million to reduce indebtedness under its Credit Facility. In addition, in 2008, the Company issued $255.9 million in aggregate principal amount of the Company's 9.875% senior notes due 2018. The Company used the net proceeds of approximately $243.6 million to repay an outstanding term loan. For additional information about the Company's debt instruments, such as interest rates and covenants, see Note 6. The Company is in compliance with all financial and other covenants of the Credit Facility and senior notes.

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 flow for investing activities and borrows as cash is needed. Absent such borrowings, 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 Item 1A. "Risk Factors."

Counterparty Credit Risk

The Company accounts for its commodity and interest rate derivatives at fair value. The Company's counterparties are participants or affiliates of participants in its Credit Facility, which is secured by the Company's oil, natural gas and NGL reserves; therefore, the Company is not required to post any collateral. The Company does not require collateral from its 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 meet the Company's minimum credit quality standard, or have a guarantee from an affiliate that meets 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 derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss due to counterparty nonperformance is somewhat mitigated.

Public Offering of Units

In October 2009, the Company sold 8,625,000 units representing limited liability company interests at $21.90 per unit ($21.024 per unit, net of underwriting discount) for net proceeds of approximately $181.1 million. In addition, in May 2009, the Company sold 6,325,000 units representing limited liability company interests at $16.25 per unit ($15.60 per unit, net of underwriting discount) for net proceeds of approximately $98.2 million. The Company used the net proceeds from each offering to reduce indebtedness under the Credit Facility. See Note 3 for additional information about the equity offerings.

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

Distributions

Under the limited liability company agreement, 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, 2009:

Date Paid	Period Covered by Distribution	Distribution Per Unit	Total Distribution
			(in millions)
November 2009	July 1 – September 30, 2009	$ 0.63	$ 81.9
August 2009	April 1 – June 30, 2009	$ 0.63	76.4
May 2009	January 1 – March 31, 2009	$ 0.63	72.5
February 2009	October 1 – December 31, 2008	$ 0.63	72.5
			$ 303.3

On January 27, 2010, the Company's Board of Directors declared a cash distribution of $0.63 per unit with respect to the fourth quarter of 2009. The distribution, totaling approximately $82.3 million, was paid on February 12, 2010, to unitholders of record as of the close of business on February 5, 2010.

Off-Balance Sheet Arrangements

The Company does not currently have any off-balance sheet arrangements.

Contingencies

In 2008, Lehman Brothers Holdings Inc. ("Lehman Holdings") and Lehman Brothers Commodity Services Inc. ("Lehman Commodity Services") filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code. At December 31, 2009, and December 31, 2008, the Company had a net receivable of approximately $6.7 million from Lehman Commodity Services for canceled derivative contracts, which is included in "other current assets" on the consolidated balance sheets. The value of the receivable was estimated based on market expectations. The Company is pursuing various legal remedies to protect its interests and 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, 2009, December 31, 2008, and December 31, 2007, 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.

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

Commitments and Contractual Obligations

The following summarizes, as of December 31, 2009, certain long-term contractual obligations that are reflected in the consolidated balance sheets and/or disclosed in the accompanying notes thereto:

	Payments Due				
Contractual Obligations	**Total**	**2010**	**2011 – 2012**	**2013 – 2014**	**2015 and Beyond**
			(in thousands)		
Long-term debt obligations:					
Credit facility	$1,100,000	$ —	$1,100,000	$ —	$ —
Senior notes	505,927	—	—	—	505,927
Interest [(1)]	516,141	87,428	161,197	109,296	158,220
Operating lease obligations:					
Office, property and equipment leases	29,965	3,954	7,811	6,526	11,674
Other noncurrent liabilities:					
Asset retirement obligations	33,135	—	—	—	33,135
Other:					
Commodity derivatives	45,654	8,185	5,787	14,271	17,411
Interest rate swaps	69,386	42,839	26,547	—	—
Services agreement	1,845	1,165	680	—	—
Charitable contributions	750	250	500	—	—
Executive severance	185	185	—	—	—
	$2,302,988	$ 144,006	$1,302,522	$ 130,093	$ 726,367

(1) Represents interest on the Credit Facility computed at the weighted average LIBOR of 2.98% through maturity in August 2012 and interest on the 2017 Notes and 2018 Notes computed at fixed rates of 11.75% and 9.875% through maturity in May 2017 and July 2018, respectively.

Capital Structure

The Company's capitalization is presented below:

	December 31, 2009	December 31, 2008
	(in thousands)	
Cash and cash equivalents	$ 22,231	$ 28,668
Credit facility	$1,100,000	$1,403,393
Senior notes due 2017, net	238,275	—
Senior notes due 2018, net	250,556	250,175
	1,588,831	1,653,568
Total unitholders' capital	2,452,004	2,760,686
	$4,040,835	$4,414,254

Non-GAAP Financial Measures

The non-GAAP financial measures adjusted EBITDA and adjusted net income, as defined by the Company, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP measures should be considered in conjunction with income from continuing operations and other performance measures prepared in accordance with GAAP, such as operating income or cash flow from operating activities. Adjusted EBITDA and adjusted net income should not be considered in isolation or as a substitute for GAAP measures, such as net income, operating income or any other GAAP measure of liquidity or financial performance.

Adjusted EBITDA (Non-GAAP Measure)

Adjusted EBITDA is a measure used by Company management to indicate (prior to the establishment of any reserves by its Board of Directors) the cash distributions the Company expects to pay unitholders. Adjusted EBITDA is also a quantitative measure used throughout the investment community with respect to publicly-traded partnerships and limited liability companies.

The Company defines adjusted EBITDA as income (loss) from continuing operations plus the following adjustments:

- Net operating cash flow from acquisitions and divestitures, effective date through closing date;
- Interest expense;
- Depreciation, depletion and amortization;
- Impairment of goodwill and long-lived assets;
- Write-off of deferred financing fees and other;
- (Gain) loss on sale of assets, net;
- Unrealized (gain) loss on commodity derivatives;
- Unrealized (gain) loss on interest rate derivatives;
- Realized (gain) loss on interest rate derivatives;
- Realized (gain) loss on canceled derivatives;
- Unit-based compensation expenses;
- Exploration costs; and
- Income tax (benefit) expense.

The following presents a reconciliation of consolidated income (loss) from continuing operations to adjusted EBITDA:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Income (loss) from continuing operations	$ (295,841)	$ 825,657	$ (356,194)
Plus:			
Net operating cash flow from acquisitions and divestitures, effective date through closing date [(1)]	3,708	3,436	67,417
Interest expense, cash	74,185	81,704	35,974
Interest expense, noncash	18,516	12,813	3,000
Depreciation, depletion and amortization	201,782	194,093	69,081
Impairment of goodwill and long-lived assets	—	50,505	—
Write-off of deferred financing fees and other	204	6,728	3,460
(Gain) loss on sale of assets, net	(23,051)	(98,763)	1,767
Unrealized (gain) loss on commodity derivatives	591,379	(734,732)	388,733
Reclassification of derivative settlements [(2)]	—	—	(5,946)
Unrealized (gain) loss on interest rate derivatives	(16,588)	50,638	29,548
Realized (gain) loss on interest rate derivatives [(3)]	42,881	16,036	(1,467)
Realized (gain) loss on canceled derivatives	(48,977)	81,358	—
Unit-based compensation expenses	15,089	14,699	13,518
Exploration costs	7,169	7,603	4,053
Income tax (benefit) expense	(4,221)	2,712	4,788
Adjusted EBITDA from continuing operations	$ 566,235	$ 514,487	$ 257,732

(1) Includes net operating cash flow from acquisitions and divestitures.

(2) During 2008, the Company revised its classification of realized and unrealized gains (losses) on natural gas derivative contracts in order to match realized gains (losses) with the related production. Amounts reported in adjusted EBITDA for all prior periods have been reclassified to conform to current period presentation. This reclassification had no effect on the Company's reported net income.

(3) During 2009, the Company revised its definition of adjusted EBITDA to include realized (gains) losses on interest rate derivatives in order to match the related interest expense. Amounts reported in adjusted EBITDA for all prior periods have been reclassified to conform to current period presentation. This reclassification had no effect on the Company's reported net income.

Net cash provided by operating activities for the year ended December 31, 2009, was approximately $426.8 million and includes cash interest payments of approximately $73.9 million, premiums paid for commodity derivatives of approximately $93.6 million, cash settlements on interest rate derivatives of approximately $41.7 million, realized gains on canceled derivatives of approximately $(49.0) million and other items of approximately $(20.8) million that are not included in adjusted EBITDA. Net cash provided by operating activities for the year ended December 31, 2008, was approximately $179.5 million and includes cash interest payments of approximately $95.0 million, premiums paid for commodity derivatives of approximately $129.5 million, cash settlements on interest rate derivatives of approximately $13.9 million, realized losses on canceled derivatives of approximately $81.4 million and other items of approximately $15.2 million that are not included in adjusted EBITDA. Net cash used in operating activities for the year ended December 31, 2007, was approximately $(44.8) million and includes cash interest payments of approximately $57.3 million, premiums paid for commodity derivatives of approximately $279.3 million and other items of approximately $(34.1) million that are not included in adjusted EBITDA.

Adjusted Net Income (Non-GAAP Measure)

Adjusted net income is a performance measure used by Company management to evaluate its operational performance from oil and natural gas properties, prior to derivative gains and losses, impairment of goodwill and long-lived assets and (gain) loss on sale of assets, net.

The following presents a reconciliation of income (loss) from continuing operations to adjusted net income:

	Year Ended December 31,		
	2009	**2008**	**2007**
	(in thousands, except per unit amounts)		
Income (loss) from continuing operations	$ (295,841)	$ 825,657	$ (356,194)
Plus:			
Unrealized (gain) loss on commodity derivatives	591,379	(734,732)	388,733
Reclassification of derivative settlements	—	—	(5,946)
Unrealized (gain) loss on interest rate derivatives	(16,588)	50,638	29,548
Realized (gain) loss on canceled derivatives	(48,977)	81,358	—
Impairment of goodwill and long-lived assets	—	50,505	—
(Gain) loss on sale of assets, net	(23,051)	(98,763)	1,767
Adjusted net income from continuing operations	$ 206,922	$ 174,663	$ 57,908
Income (loss) from continuing operations per unit – basic	$ (2.48)	$ 7.18	$ (5.17)
Plus, per unit:			
Unrealized (gain) loss on commodity derivatives	4.95	(6.39)	5.64
Reclassification of derivative settlements	—	—	(0.09)
Unrealized (gain) loss on interest rate derivatives	(0.14)	0.44	0.43
Realized (gain) loss on canceled derivatives	(0.41)	0.71	—
Impairment of goodwill and long-lived assets	—	0.44	—
(Gain) loss on sale of assets, net	(0.19)	(0.86)	0.03
Adjusted net income from continuing operations per unit – basic	$ 1.73	$ 1.52	$ 0.84

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

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 United States 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, natural gas and NGL, future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, fair values of commodity and interest rate derivatives, and fair values of assets acquired and liabilities assumed. 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 details about additional accounting policies and estimates made by Company management.

Oil and Natural Gas Reserves

Proved reserves are based on the quantities of oil, natural gas and NGL that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. 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, 2009, and the reserve estimates reported herein were prepared by DeGolyer and MacNaughton. The reserve estimates were reviewed and approved by the Company's senior engineering staff and management, with final approval by its Senior Vice President and Chief Operating Officer.

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 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, based in part on data provided by the Company. The 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.

The accuracy of 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. In addition, 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, natural gas and NGL eventually recovered. For additional information regarding estimates of reserves, including the standardized measure of discounted future net cash flows, see "Supplemental Oil and Natural Gas Data (Unaudited)" in Item 8. "Financial Statements and Supplementary Data" and see also Item 1. "Business."

Oil and Natural Gas Properties

Proved Properties

The Company accounts for oil and natural gas properties in accordance with the successful efforts method. In accordance with 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 natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows are less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Company 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 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 natural 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 $0.3 million, $0.9 million and $0.5 million for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, respectively.

Unproved Properties

Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. 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 expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved properties for impairment quarterly on the basis of its experience in similar situations and other factors such as the primary lease terms of the 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. The fair values of unproved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of unproved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors.

Impairment

Based on the analysis described above, the Company recorded noncash impairment of proved 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 statements of operations. The Company recorded no impairment of proved properties in continuing operations for the years ended December 31, 2009, or December 31, 2007. The Company recorded noncash impairment of unproved properties of approximately $6.3 million and $4.5 million for the years ended December 31, 2009, and December 31, 2008, which is included in "exploration costs" on the consolidated statements of operations. The Company recorded no such impairment for the year ended December 31, 2007.

Exploration Costs
Geological and geophysical costs, delay rentals, amortization and impairment of unproved leasehold costs and costs to drill exploratory wells that do not find proved reserves are expensed as 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.

Revenue Recognition

Sales of oil, natural gas and NGL are recognized when the product 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.

The Company has elected the entitlements method to account for natural gas production imbalances. Imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. In accordance with 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, 2009, and December 31, 2008, the Company had natural gas production imbalance receivables of approximately $16.4 million and $17.1 million, respectively, which are included in "accounts receivable – trade, net" on the consolidated balance sheets and natural gas production imbalance payables of approximately $8.8 million and $9.9 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 natural gas and subsequently markets such natural gas to independent purchasers under separate arrangements. As such, the Company separately reports third-party marketing sales and natural gas marketing expenses. Marketing margins related to the Company's production are included in oil, natural gas and NGL sales.

Asset Retirement Obligations

The Company has the obligation to plug and abandon oil and natural 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 statements of operations. The fair values of additions to the asset retirement obligation liability are estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plug and abandon costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors; and (iv) a credit-adjusted risk-free interest rate. 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 10).

Derivative Instruments

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil, natural gas and NGL. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. These transactions are primarily in the form of swap contracts, put options and collars. A swap contract specifies a fixed price that the Company will receive from the counterparty as compared to floating market prices, and on the settlement date the Company will receive or pay the difference between the swap price and the market price. 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 price floor over the market price at the settlement date. A collar specifies the range of prices that the Company will receive as compared to floating market prices and on the settlement date offers the Company the opportunity to receive up to the price ceiling while protecting against downside risk below the price floor. In addition, the Company enters into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates.

Derivative instruments (including certain derivative instruments embedded in other contracts) are recorded at fair value and included on the consolidated balance sheets as assets or liabilities. The Company did not designate these contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. The Company determines the fair value of its derivative financial instruments utilizing pricing models for significantly similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. See Note 7 and Note 8 for additional details about the Company's derivative financial instruments. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for sensitivity analysis regarding the Company's derivative financial instruments.

Acquisition Accounting

The Company accounts for business combinations under the acquisition method of accounting in accordance with an accounting standard adopted by the Company effective January 1, 2009, (see Note 2). Accordingly, the Company recognizes amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. Transaction and integration costs associated with business combinations are expensed as incurred.

The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The most significant assumptions relate to the estimated fair values of proved and unproved oil and natural gas properties. The fair values of these properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is 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 are reduced by additional risk-weighting factors. In addition, when appropriate, the Company reviews comparable purchases and sales of oil and natural 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 the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill while any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain. Deferred taxes are 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 estimated fair values of the assets acquired and liabilities assumed have no effect on cash flow, they can have an effect on future results of operations. Generally, higher fair values assigned to oil and natural 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 natural gas properties, based on higher future estimates of commodity 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 impairment expense has no effect on cash flow but results in a decrease in net income for the period in which the impairment is recorded.

Unit-Based Compensation

The Company recognizes expense for unit-based compensation over the requisite service period, in an amount equal to the fair value of unit-based payments granted to employees and nonemployee directors. See Note 1 and Note 5 for additional details about the Company's accounting for unit-based compensation.

New Accounting Standards

See Note 12 and Note 17 for details regarding the Company's implementation of new accounting standards.

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 commodity 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 trading.

The following should be read in conjunction with the financial statements and related notes included elsewhere in this Annual Report on Form 10-K. 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 7). At December 31, 2009, the fair value of contracts that settle during the next 12 months was an asset of approximately $227.6 million and a liability of $8.1 for a net asset of approximately $219.5 million. A 10% increase in the index oil and natural gas prices above the December 31, 2009, prices for the next 12 months would result in a net asset of approximately $130.7 million which represents a decrease in the fair value of approximately $88.8 million; conversely, a 10% decrease in the index oil and natural gas prices would result in a net asset of approximately $310.3 million which represents an increase in the fair value of approximately $90.8 million.

Interest Rate Risk

At December 31, 2009, the Company had long-term debt outstanding under its Credit Facility of approximately $1.10 billion, which incurred interest at floating rates (see Note 6). A 1% increase in LIBOR would result in an estimated $11.0 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 7).

Counterparty Credit Risk

The Company accounts for its commodity and interest rate derivatives at fair value on a recurring basis (see Note 8). 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, 2009, the average public bond yield spread utilized to estimate the impact of the Company's credit risk on derivative liabilities was approximately 4.25%. A 1% increase in the average public bond yield spread would result in an estimated $2.1 million increase in net income for the year ended December 31, 2009. At December 31, 2009, the credit default swap spreads utilized to estimate the impact of counterparties' credit risk on derivative assets ranged between 0% and 1.35%. A 1% increase in each of the counterparties' credit default swap spreads would result in an estimated $3.3 million decrease in net income for the year ended December 31, 2009.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

	Page
Management's Report on Internal Control Over Financial Reporting	66
Report of Independent Registered Public Accounting Firm (Financial Statements)	67
Report of Independent Registered Public Accounting Firm (Internal Control Over Financial Reporting)	68
Consolidated Balance Sheets, as of December 31, 2009, and December 31, 2008	69
Consolidated Statements of Operations, for the years ended December 31, 2009, December 31, 2008, and December 31, 2007	70
Consolidated Statements of Unitholders' Capital, for the years ended December 31, 2009, December 31, 2008, and December 31, 2007	71
Consolidated Statements of Cash Flows, for the years ended December 31, 2009, December 31, 2008, and December 31, 2007	72
Notes to Consolidated Financial Statements	73
Supplemental Oil and Natural Gas Data (Unaudited)	105
Supplemental Quarterly Data (Unaudited)	111

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, 2009, 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, 2009, 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, 2009, which is included herein.

/s/ Linn Energy, LLC

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, 2009 and 2008, and the related consolidated statements of operations, unitholders' capital, and cash flows for each of the years in the three-year period ended December 31, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, 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, 2009, 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, 2010, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 25, 2010

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, 2009, 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, 2009, 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, 2009 and 2008, and the related consolidated statements of operations, unitholders' capital and cash flows for each of the years in the three-year period ended December 31, 2009, and our report dated February 25, 2010, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 25, 2010

LINN ENERGY, LLC
CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(in thousands, except unit amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 22,231	$ 28,668
Accounts receivable – trade, net	109,311	138,983
Derivative instruments	249,756	368,951
Other current assets	28,162	27,329
Total current assets	409,460	563,931
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	4,076,795	3,831,183
Less accumulated depletion and amortization	(463,413)	(278,805)
	3,613,382	3,552,378
Other property and equipment	118,867	111,459
Less accumulated depreciation	(23,583)	(13,171)
	95,284	98,288
Derivative instruments	145,457	493,705
Other noncurrent assets	76,673	13,718
	222,130	507,423
Total noncurrent assets	3,930,796	4,158,089
Total assets	$ 4,340,256	$ 4,722,020
LIABILITIES AND UNITHOLDERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued expenses	$ 124,358	$ 163,662
Derivative instruments	51,025	47,005
Other accrued liabilities	33,922	27,163
Total current liabilities	209,305	237,830
Noncurrent liabilities:		
Credit facility	1,100,000	1,403,393
Senior notes, net	488,831	250,175
Derivative instruments	53,923	39,350
Other noncurrent liabilities	36,193	30,586
Total noncurrent liabilities	1,678,947	1,723,504
Unitholders' capital:		
129,940,617 units and 114,079,533 units issued and outstanding at December 31, 2009, and December 31, 2008, respectively	2,098,599	2,109,089
Accumulated income	353,405	651,597
	2,452,004	2,760,686
Total liabilities and unitholders' capital	$ 4,340,256	$ 4,722,020

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

LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	2008	2007
	(in thousands, except per unit amounts)		
Revenues and other:			
Oil, natural gas and natural gas liquid sales	$ 408,219	$ 755,644	$ 255,927
Gain (loss) on oil and natural gas derivatives	(141,374)	662,782	(345,537)
Natural gas marketing revenues	4,380	12,846	11,589
Other revenues	1,924	3,759	2,738
	273,149	1,435,031	(75,283)
Expenses:			
Lease operating expenses	132,647	115,402	41,946
Transportation expenses	18,202	17,597	5,575
Natural gas marketing expenses	2,154	11,070	9,100
General and administrative expenses	86,134	77,391	51,374
Exploration costs	7,169	7,603	4,053
Bad debt expenses	401	1,436	—
Depreciation, depletion and amortization	201,782	194,093	69,081
Impairment of goodwill and long-lived assets	—	50,505	—
Taxes, other than income taxes	27,605	61,435	22,350
(Gain) loss on sale of assets and other, net	(24,598)	(98,763)	1,767
	451,496	437,769	205,246
Other income and (expenses):			
Interest expense, net of amounts capitalized	(92,701)	(94,517)	(38,974)
Loss on interest rate swaps	(26,353)	(66,674)	(28,081)
Other, net	(2,661)	(7,702)	(3,822)
	(121,715)	(168,893)	(70,877)
Income (loss) from continuing operations before income taxes	(300,062)	828,369	(351,406)
Income tax benefit (expense)	4,221	(2,712)	(4,788)
Income (loss) from continuing operations	(295,841)	825,657	(356,194)
Discontinued operations:			
Gain (loss) on sale of assets, net of taxes	(158)	159,045	936
Income (loss) from discontinued operations, net of taxes	(2,193)	14,914	(9,091)
	(2,351)	173,959	(8,155)
Net income (loss)	$ (298,192)	$ 999,616	$ (364,349)
Income (loss) per unit – continuing operations:			
Basic	$ (2.48)	$ 7.18	$ (5.17)
Diluted	$ (2.48)	$ 7.18	$ (5.17)
Income (loss) per unit – discontinued operations:			
Basic	$ (0.02)	$ 1.52	$ (0.12)
Diluted	$ (0.02)	$ 1.52	$ (0.12)
Net income (loss) per unit:			
Basic	$ (2.50)	$ 8.70	$ (5.29)
Diluted	$ (2.50)	$ 8.70	$ (5.29)
Weighted average units outstanding:			
Basic	119,307	114,140	68,916
Diluted	119,307	114,158	68,916
Distributions declared per unit	$ 2.52	$ 2.52	$ 2.18

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

LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF UNITHOLDERS' CAPITAL

	Units	Unitholders' Capital	Accumulated Income (Deficit)	Treasury Units (at Cost)	Total Unitholders' Capital
			(in thousands)		
December 31, 2006	42,803	$ 434,624	$ 16,330	$ —	$ 450,954
Sale of units, net of expenses 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)
Unit-based compensation expenses		15,677	—	—	15,677
Reclassification of distributions paid on forfeited restricted units		182	—	—	182
Net income		—	999,616	—	999,616
December 31, 2008	114,080	2,109,089	651,597	—	2,760,686
Sale of units, net of underwriting discounts and expenses of $12,369	14,950	279,299	—	—	279,299
Issuance of units	1,098	494	—	—	494
Cancellation of units	(187)	(2,696)	—	2,696	—
Purchase of units		—	—	(2,696)	(2,696)
Distributions to unitholders		(303,316)	—	—	(303,316)
Unit-based compensation expenses		15,089	—	—	15,089
Reclassification of distributions paid on forfeited restricted units		63	—	—	63
Excess tax benefit from unit-based compensation		577	—	—	577
Net loss		—	(298,192)	—	(298,192)
December 31, 2009	129,941	$ 2,098,599	$ 353,405	$ —	$ 2,452,004

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

LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Cash flow from operating activities:			
Net income (loss)	$ (298,192)	$ 999,616	$ (364,349)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	201,782	200,306	94,200
Impairment of goodwill and long-lived assets	—	50,505	3,343
Unit-based compensation expenses	15,089	15,677	13,921
Bad debt expenses	401	1,436	—
Amortization and write-off of deferred financing fees and other	21,824	17,024	5,746
(Gain) loss on sale of assets, net	(23,243)	(257,808)	831
Deferred income tax	(6,436)	—	3,360
Mark-to-market on derivatives:			
Total (gains) losses	167,727	(596,108)	373,618
Cash settlements	362,936	(20,901)	40,784
Cash settlements on canceled derivatives	48,977	(81,358)	—
Premiums paid for derivatives	(93,606)	(129,520)	(279,313)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable – trade, net	29,117	9,572	(117,361)
(Increase) decrease in other assets	(3,051)	(8,455)	3,286
Increase (decrease) in accounts payable and accrued expenses	(4,675)	(36,451)	161,844
Increase in other liabilities	8,154	15,980	15,276
Net cash provided by (used in) operating activities	426,804	179,515	(44,814)
Cash flow from investing activities:			
Acquisition of oil and natural gas properties	(130,735)	(593,412)	(2,677,575)
Development of oil and natural gas properties	(170,458)	(330,615)	(185,534)
Purchases of other property and equipment	(7,784)	(9,109)	(33,849)
Proceeds from sale of properties and equipment	26,704	897,586	4,538
Net cash used in investing activities	(282,273)	(35,550)	(2,892,420)
Cash flow from financing activities:			
Proceeds from sale of units	291,668	—	2,120,000
Purchase of units	(2,696)	(14,998)	(7,399)
Proceeds from borrowings	639,203	1,459,000	1,298,000
Repayments of debt	(704,893)	(1,250,172)	(283,108)
Distributions to unitholders	(303,316)	(289,915)	(154,963)
Financing fees, offering expenses and other, net	(70,934)	(20,653)	(40,450)
Net cash provided by (used in) financing activities	(150,968)	(116,738)	2,932,080
Net increase (decrease) in cash and cash equivalents	(6,437)	27,227	(5,154)
Cash and cash equivalents:			
Beginning	28,668	1,441	6,595
Ending	$ 22,231	$ 28,668	$ 1,441

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

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 natural gas company that 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." LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. The Company's properties are located in the United States, primarily in the Mid-Continent, California and the Permian Basin.

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, as amended (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 United States 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. Subsequent events were evaluated through the issuance date of the financial statements.

(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 statements of operations for all periods presented. Unless otherwise indicated, information about the consolidated statements of operations that is presented in the notes to consolidated financial statements relates only to continuing operations.

(d) *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, natural gas and natural gas liquids ("NGL"), future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, fair values of commodity and interest rate derivatives, and fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. 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.

(e) ***Cash Equivalents***

For purposes of the consolidated statements of cash flows, the Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents.

(f) ***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 $1.7 million and $1.5 million at December 31, 2009, and December 31, 2008, respectively.

(g) ***Inventories***

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

(h) ***Oil and Natural Gas Properties***

Proved Properties

The Company accounts for oil and natural gas properties in accordance with the successful efforts method. In accordance with 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 natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows are less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with New York Mercantile Exchange ("NYMEX") forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Company 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 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 natural 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 $0.3 million, $0.9 million and $0.5 million for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, respectively.

Unproved Properties
Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. 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 expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved properties for impairment quarterly on the basis of its experience in similar situations and other factors such as the primary lease terms of the 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. The fair values of unproved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of unproved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors.

Impairment
Based on the analysis described above, the Company recorded noncash impairment of proved 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 statements of operations. The Company recorded no impairment of proved properties in continuing operations for the years ended December 31, 2009, or December 31, 2007. The Company recorded noncash impairment of unproved properties of approximately $6.3 million and $4.5 million for the years ended December 31, 2009, and December 31, 2008, which is included in "exploration costs" on the consolidated statements of operations. The Company recorded no such impairment for the year ended December 31, 2007.

Exploration Costs
Geological and geophysical costs, delay rentals, amortization and impairment of unproved leasehold costs and costs to drill exploratory wells that do not find proved reserves are expensed as 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.

(i) Other Property and Equipment
Other property and equipment includes natural 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 three to 39 years for the individual asset or group of assets.

(j) Goodwill Impairment
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. These adjustments reduced the balance of goodwill by approximately $44.1 million.

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 that had adverse impacts on stock markets and 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 of 2008, the Company's market capitalization value was below the recorded net book value of its consolidated balance sheet, including goodwill. Because quoted market prices for the Company's reporting units were not available, management used judgment in estimating the 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.

At December 31, 2008, based on its impairment analysis, the Company concluded that impairment of the entire amount of recorded goodwill for the Mid-Continent Deep reporting unit was required. A $20.3 million before and after tax noncash 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 statements of operations. The Company had no goodwill recorded on its consolidated balance sheets at December 31, 2009, or December 31, 2008.

(k) Revenue Recognition

Revenues representative of the Company's ownership interest in its properties are presented on a gross basis on the consolidated statements of operations. Sales of oil, natural gas and NGL are recognized when the product 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.

The Company has elected the entitlements method to account for natural gas production imbalances. Imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. In accordance with 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, 2009, and December 31, 2008, the Company had natural gas production imbalance receivables of approximately $16.4 million and $17.1 million, respectively, which are included in "accounts receivable – trade, net" on the consolidated balance sheets and natural gas production imbalance payables of approximately $8.8 million and $9.9 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 natural gas and subsequently markets such natural gas to independent purchasers under separate arrangements. As such, the Company separately reports third-party marketing sales and natural gas marketing expenses. Marketing margins related to the Company's production are included in oil, natural gas and NGL sales.

The Company generates electricity with excess natural 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 statements of operations.

(l) Restricted Cash

Restricted cash of $2.1 million and $1.3 million is included in "other noncurrent assets" on the consolidated balance sheets at December 31, 2009, and December 31, 2008, 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 reduce exposure to fluctuations in the prices of oil, natural gas and NGL. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. These transactions are primarily in the form of swap contracts, put options and collars. In addition, the Company enters into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates.

Derivative instruments (including certain derivative instruments embedded in other contracts) are recorded at fair value and included on the consolidated balance sheets as assets or liabilities. The Company did not designate these contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. The Company determines the fair value of its derivative financial instruments utilizing pricing models for significantly similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. See Note 7 and Note 8 for additional details about the Company's derivative financial instruments.

(n) Unit-Based Compensation

The Company recognizes expense for unit-based compensation over the requisite service period, in an amount equal to the fair value of unit-based payments granted to employees and nonemployee directors. The fair value of unit-based payments, excluding liability awards, is computed at the date of grant and is not 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.

The Company has made a policy decision to recognize compensation expense for service-based awards on a straight-line basis over the requisite service period for the entire award. See Note 5 for additional details about the Company's accounting for unit-based compensation.

The benefit of tax deductions in excess of recognized compensation costs is required to be reported as financing cash flow, rather than operating cash flow. This requirement reduces net operating cash flow and increases net financing cash flow in periods in which such tax benefit exists. The amount of the Company's excess tax benefit is reported in "excess tax benefit from unit-based compensation" on the consolidated statements of unitholders' capital.

(o) ***Deferred Financing Fees***

The Company incurred legal and bank fees related to the issuance of debt (see Note 6). At December 31, 2009, and December 31, 2008, net deferred financing fees of approximately $57.6 million and $11.9 million, respectively, are included in "other noncurrent assets" on the consolidated balance sheets. These debt issuance costs are amortized over the life of the debt agreement. For the years ended December 31, 2009, December 31, 2008, and December 31, 2007, amortization expense of $13.7 million, $5.2 million and $1.5 million, respectively, is included in "interest expense, net of amounts capitalized" on the consolidated statements of operations.

(p) ***Fair Value of Financial Instruments***

The carrying values of the Company's receivables, payables and Credit Facility (as defined in Note 6) are estimated to be substantially the same as their fair values at December 31, 2009, and December 31, 2008. See Note 6 for fair value disclosures related to the Company's other outstanding debt. As noted above, the Company carries its derivative financial instruments at fair value. See Note 8 for details about the fair value of the Company's derivative financial instruments.

(q) ***Income Taxes***

The Company is a limited liability company 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 passed through to unitholders. As such, with the exception of the state of Texas, 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 federal and state income taxes, which are accounted for using 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 14 for detail of amounts recorded in the consolidated financial statements.

(2) Acquisitions, Divestitures and Discontinued Operations

Acquisitions – 2009

On August 31, 2009, and September 30, 2009, the Company completed the acquisitions of certain oil and natural gas properties located in the Permian Basin in Texas and New Mexico from Forest Oil Corporation and Forest Oil Permian Corporation (collectively referred to as "Forest"). The results of operations of these properties have been included in the consolidated financial statements since these dates. The Company paid $114.4 million in cash, net of cash received from Forest post-closing, and recorded a receivable from Forest, resulting in total consideration for the acquisitions of approximately $113.7 million. The transactions were financed with borrowings under the Company's Credit Facility. The acquisitions represent a strategic entry into the Permian Basin for the Company.

The acquisitions were accounted for under the acquisition method of accounting in accordance with an accounting standard adopted by the Company effective January 1, 2009, (see Note 17). Accordingly, the Company conducted an assessment of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisitions were expensed as incurred.

The following presents the values assigned to the net assets acquired as of the acquisition dates (in thousands):

Assets:		
Current and other assets	$	840
Oil and natural gas properties		115,798
Total assets acquired	$	116,638
Liabilities:		
Current liabilities	$	1,568
Asset retirement obligations		1,350
Total liabilities assumed	$	2,918
Net assets acquired	$	113,720

Current and other assets include vehicles, natural gas imbalance receivables, prepaid ad valorem taxes, and inventory of oil produced but not yet sold. Current liabilities include natural gas imbalance payables, ad valorem taxes payable and environmental liabilities.

The fair values of oil and natural gas properties and asset retirement obligation liabilities were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. Significant inputs to the valuation of asset retirement obligation liabilities include estimates of: (i) plug and abandon costs per well; (ii) remaining life per well; (iii) future inflation factors; and (iv) a credit-adjusted risk-free interest rate.

Acquisitions – 2008 and 2007

Acquisitions completed prior to January 1, 2009, were accounted for under the purchase method of accounting. The following is a summary of certain significant acquisitions completed by the Company during the years ended December 31, 2008, and December 31, 2007:

- January 31, 2008, acquisition of certain oil and natural gas properties located primarily in the Mid-Continent Shallow region, primarily in Oklahoma, from Lamamco Drilling Company for approximately $542.2 million

- August 31, 2007, acquisition of certain oil and natural gas properties in the Mid-Continent Deep region, in Oklahoma, Kansas and the Texas Panhandle, from Dominion Resources, Inc. for approximately $2.11 billion

- June 12, 2007, acquisition of certain oil and natural gas properties in the Mid-Continent Shallow region, in the Texas Panhandle, for approximately $89.7 million

- February 1, 2007, acquisition of certain oil and natural gas properties in the Mid-Continent Shallow region, in the Texas Panhandle, from Stallion Energy LLC, acting as general partner for Cavallo Energy, LP, for approximately $415.6 million

Acquisition – Subsequent Event

On January 29, 2010, the Company completed the acquisition of certain oil and natural gas properties located in the Anadarko Basin in Oklahoma and Kansas and the Permian Basin in Texas and New Mexico, from certain affiliates of Merit Energy Company ("Merit") for a contract price of $154.5 million. The transaction was financed with borrowings under the Company's Credit Facility and included a deposit of $15.5 million paid by the Company to Merit in November 2009. At December 31, 2009, this amount is reported in "other noncurrent assets" on the consolidated balance sheets. The acquisition provides an addition to the Company's asset portfolio in the Permian Basin and Mid-Continent. The initial accounting for the business combination is not complete pending detailed analyses of the facts and circumstances that existed as of the acquisition date.

Divestitures

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. During 2008, the Company received net proceeds of $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 and other, net" on the consolidated statements of operations for the year ended December 31, 2008. In the first quarter of 2009, certain post-closing matters were resolved and the Company recorded a gain of $25.4 million, which is recorded in "(gain) loss on sale of assets and other, net" on the consolidated statements of operations for the year ended December 31, 2009.

On August 15, 2008, the Company completed the sale of certain properties in the Verden area in Oklahoma to Laredo Petroleum, Inc. During 2008, the Company received net proceeds equal to the carrying value of net assets sold of $169.4 million.

On July 1, 2008, the Company completed the sale of its interests in oil and natural gas properties located in the Appalachian Basin to XTO Energy, Inc. During 2008, the Company received net proceeds of $566.5 million. The carrying value of net assets sold was $405.8 million, resulting in a gain on the sale of $160.7 million 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 and recorded a loss on the sale of $1.6 million. The gain and loss from these divestitures are recorded in "discontinued operations: (gain) loss on sale of assets, net of taxes" on the consolidated statements of operations for the year ended December 31, 2008. The Company used the net proceeds from all divestitures to reduce indebtedness.

Discontinued Operations

The Company's Appalachian Basin and Mid Atlantic operations (see "Divestitures" above) have been classified as discontinued operations on the consolidated statements of operations for all periods presented. 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,		
	2009	2008	2007
		(in thousands)	
Total revenues and other	$ (1,216)	$ 50,601	$ 67,110
Total operating expenses	(977)	(23,677)	(54,260)
Interest expense	—	(13,401)	(23,156)
Income (loss) from discontinued operations	(2,193)	13,523	(10,306)
Income tax benefit	—	1,391	1,215
Income (loss) from discontinued operations, net of taxes	$ (2,193)	$ 14,914	$ (9,091)

Discontinued operations activity for 2009 primarily represents activity related to post-closing adjustments. The Company computed interest expense related to discontinued operations for 2008 and 2007 based on debt required to be repaid as a result of the disposal transaction.

(3) Unitholders' Capital

Public Offering of Units

In October 2009, the Company sold 8,625,000 units representing limited liability company interests at $21.90 per unit ($21.024 per unit, net of underwriting discount) for net proceeds (after underwriting discount of $7.6 million and offering expenses of $0.2 million) of approximately $181.1 million, which was used to reduce indebtedness under the Credit Facility.

In May 2009, the Company sold 6,325,000 units representing limited liability company interests at $16.25 per unit ($15.60 per unit, net of underwriting discount) for net proceeds (after underwriting discount of $4.1 million and offering expenses of $0.4 million) of approximately $98.2 million, which was used to reduce indebtedness under the Credit Facility.

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 from time to time on the open market or in negotiated purchases. During the year ended December 31, 2009, 123,800 units were repurchased at an average unit price of $12.99, for a total cost of approximately $1.6 million. 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. At December 31, 2009, approximately $85.4 million was available for unit repurchase under the program. The timing and amounts of any such repurchases will be at the discretion of management, subject to market conditions and other factors, and 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 repurchased at fair market value on the date of repurchase.

Issuance and Cancellation of Units

During the year ended December 31, 2009, the Company purchased 63,031 units for approximately $1.1 million, in conjunction with units received by the Company for the payment of minimum withholding taxes due on units issued under its equity compensation plan (see Note 5). All units were subsequently canceled.

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 the year ended December 31, 2008, the Company issued 600,000 units in connection with the acquisition of certain natural 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 minimum withholding taxes due on units issued under its equity compensation plan. 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 natural 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 minimum withholding taxes due on units issued under its equity compensation plan. 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 acquisition of oil and natural gas properties. 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 reduce 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 fund the acquisition of oil and natural gas properties. The Class C units were converted into units on a one-for-one basis in April 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 statements of operations for the year ended December 31, 2007.

Distributions

Under the 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. On January 27, 2010, the Company's Board of Directors declared a cash distribution of $0.63 per unit with respect to the fourth quarter of 2009. The distribution, totaling approximately $82.3 million, was paid February 12, 2010, to unitholders of record as of the close of business February 5, 2010.

(4) 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 natural 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 natural gas purchasers and the Company generally does not require collateral, since it has not experienced significant 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, 2009, the Company's three largest customers represented 22%, 18% and 15%, respectively, of the Company's sales. For the year ended December 31, 2008, the Company's three largest customers represented 21%, 18% and 10%, respectively, of the Company's sales. For the year ended December 31, 2007, the Company's two largest customers represented 27% and 22%, respectively, of the Company's sales.

At December 31, 2009, trade accounts receivable from three customers accounted for more than 10% of the Company's total trade accounts receivable. At December 31, 2009, trade accounts receivable from these customers represented approximately 25%, 15% and 15%, respectively, of the Company's receivables. At December 31, 2008, trade accounts receivable from two customers accounted for more than 10% of the Company's total trade accounts receivable. At December 31, 2008, trade accounts receivable from these customers represented approximately 20% and 16%, respectively, of the Company's receivables.

(5) Unit-Based Compensation and Other Benefit Plans

Incentive Plan Summary

The Amended and Restated Linn Energy, LLC Long-Term Incentive Plan, as amended (the "Plan") originally became effective in December 2005. The Plan, which is administered by the Compensation Committee of the Board of Directors ("Compensation Committee"), permits the granting of unit grants, unit options, restricted units, phantom units and unit appreciation rights to employees, consultants and nonemployee 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 10 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 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 units, or an award 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, 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 service 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 or service relationship 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 contain terms as determined by the Compensation Committee, including the period or terms over which phantom units 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, 2009, 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, 2009, approximately 1.9 million units were issuable under the Plan pursuant to outstanding award or other agreements, and 6.8 million additional units were reserved for future issuance under the Plan.

Accounting for Unit-Based Compensation

Activities and balances presented in this Note 5 include amounts associated with discontinued operations for the years ended December 31, 2008, and December 31, 2007, (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 nonemployee 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 statements of operations. A summary of unit-based compensation expenses included on the consolidated statements of operations is presented below:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
General and administrative expenses	$ 14,743	$ 14,590	$ 12,118
Lease operating expenses	346	109	—
Income (loss) from discontinued operations, net of taxes	—	978	403
Total unit-based compensation expenses	$ 15,089	$ 15,677	$ 12,521
Income tax benefit	$ 5,968	$ —	$ —

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 nonvested units as of December 31, 2009, is presented below:

	Number of Nonvested Units	Weighted Average Grant-Date Fair Value
Nonvested units at December 31, 2008	835,004	$ 27.01
Granted	1,115,255	$ 16.11
Vested	(409,227)	$ 27.43
Forfeited	(41,244)	$ 17.09
Nonvested units at December 31, 2009	1,499,788	$ 19.07

The weighted average grant-date fair value of unrestricted unit grants and restricted units granted during the years ended December 31, 2008, and December 31, 2007, was $23.82 and $31.16, respectively.

As of December 31, 2009, there was approximately $16.1 million of unrecognized compensation cost related to nonvested restricted units. The cost is expected to be recognized over a weighted average period of approximately 1.33 years. The total fair value of units that vested was approximately $11.2 million, $14.0 million and $19.4 million for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, respectively.

Changes in Unit Options and Unit Options Outstanding

The following provides information related to unit option activity for the year ended December 31, 2009:

	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, 2008	1,590,438	$ 24.04	$ 3.76	8.23
Granted	382,405	$ 15.95	$ 0.55	
Exercised	(25,000)	$ 19.74	$ 3.75	
Outstanding at December 31, 2009	1,947,843	$ 22.51	$ 3.13	7.43
Exercisable at December 31, 2009	1,147,705	$ 24.44	$ 4.21	6.65

The weighted average grant-date fair value of options granted during the years ended December 31, 2008, and December 31, 2007, was $2.58 and $4.59, respectively. The total intrinsic value of options exercised during the years ended December 31, 2009, December 31, 2008, and December 31, 2007, was approximately $124,000, $4,000 and $95,000, respectively. The Company received $0.5 million from the exercise of options during the year ended December 31, 2009. No options were forfeited during the year ended December 31, 2009.

As of December 31, 2009, there was approximately $0.6 million of total unrecognized compensation cost related to nonvested unit options. The cost is expected to be recognized over a weighted average period of approximately 1.04 years. In addition, the exercisable unit options at December 31, 2009, have an aggregate intrinsic value of approximately $4.7 million and all outstanding unit options have an aggregate intrinsic value of approximately $11.5 million. The total fair value of all options that vested during the years ended December 31, 2009, December 31, 2008, and December 31, 2007, was approximately $1.7 million, $2.1 million and $1.5 million, respectively. No options expired during the years ended December 31, 2009, December 31, 2008, or December 31, 2007.

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 natural 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:

	2009	2008	2007
Expected volatility	30.59%	30.59% – 34.57%	30.40% – 35.58%
Expected distributions	15.80% – 16.79%	10.13% – 12.32%	6.51% – 10.67%
Risk-free rate	1.24% – 1.91%	2.66% – 3.41%	3.53% – 5.18%
Expected term	5 years	5 years	5 years

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

In January 2010, the Company granted 638,554 restricted units as part of its annual review of employee and executive compensation.

Nonemployee 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, 2009, and expire 10 years from issuance. The Company computed the fair value of the unit warrants using a Black-Scholes pricing model. The expense of approximately $1.4 million is included in "general and administrative expenses" on the consolidated statements 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 consisted of a discretionary matching contribution equal to 100% of the first 4% of eligible compensation contributed by the employee on a before-tax basis for each of the years in the three year period ending December 31, 2009. Effective January 1, 2010, the Company contribution was equal to 100% of the first 6% of eligible employee compensation. The Company contributed approximately $1.7 million, $1.6 million and $0.8 million during the years ended December 31, 2009, December 31, 2008, and December 31, 2007, 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.

(6) Debt

The following summarizes debt outstanding:

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value [1]	Carrying Value	Fair Value [1]
	(in thousands)			
Credit facility [2]	$ 1,100,000	$ 1,100,000	$ 1,403,393	$ 1,403,393
Senior notes due 2017, net [3]	238,275	279,375	—	—
Senior notes due 2018, net [4]	250,556	270,803	250,175	147,268
Less current maturities	—	—	—	—
	$ 1,588,831	$ 1,650,178	$ 1,653,568	$ 1,550,661

(1) The carrying value of the Credit Facility is estimated to be substantially the same as its fair value. Fair values of the senior notes were estimated based on prices quoted from third-party financial institutions.

(2) Variable interest rate of 2.98% at December 31, 2009, and 2.47% at December 31, 2008.

(3) Fixed interest rate of 11.75% and effective interest rate of 12.73%. Amount is net of unamortized discount of approximately $11.7 million at December 31, 2009.

(4) Fixed interest rate of 9.875% and effective interest rate of 10.25%. Amount is net of unamortized discount of approximately $5.4 million and $5.8 million at December 31, 2009, and December 31, 2008, respectively.

Credit Facility

On April 28, 2009, the Company entered into a Fourth Amended and Restated Credit Agreement ("Credit Facility"), with an initial borrowing base of $1.75 billion and a maturity of August 2012, which amended and restated the Company's existing credit facility, which had a maturity of August 2010. The terms of the Credit Facility required that, upon the issuance of the senior notes due 2017 in May 2009 (see below) and cancellation of certain commodity derivatives in July 2009 (see Note 7), the borrowing base be decreased by approximately $62.5 million and $45.0 million, respectively, to $1.64 billion at December 31, 2009. At December 31, 2009, available borrowing capacity was $537.0 million, which includes a $5.5 million reduction in availability for outstanding letters of credit. In connection with the amended and restated Credit Facility, during the year ended December 31, 2009, the Company paid approximately $52.7 million in financing fees and expenses, which were deferred and will be amortized over the life of the Credit Facility.

Redetermination of the borrowing base under the Credit Facility occurs semi-annually, in April and October, as well as upon the occurrence of certain events, by the lenders in their sole discretion, based primarily on reserve reports that reflect commodity prices at such time. Significant declines in prices may result in a decrease in the borrowing base. The Company's obligations under the Credit Facility are secured by mortgages on its oil and natural 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 properties. Additionally, the obligations under the Credit Facility are guaranteed by all of the Company's material 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 2.50% and 3.25% per annum or the alternate base rate ("ABR") plus an applicable margin between 1.00% and 1.75% 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 of 0.5% per annum on the unused portion of the borrowing base under the Credit Facility.

The Credit Facility contains various covenants, substantially similar to those included prior to the amendment and restatement, which limit the Company's ability to: (i) incur indebtedness; (ii) enter into commodity and interest rate swaps; (iii) grant certain liens; (iv) make certain loans, acquisitions, capital expenditures and investments; (v) make distributions other than from available cash; and (vi) merge or consolidate, or engage in certain asset dispositions, including a sale of all or substantially all of its assets. The Credit Facility also contains covenants, substantially similar to those included prior to the amendment and restatement, which 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 the Credit Facility.

Senior Notes Due 2017

On May 12, 2009, the Company entered into a purchase agreement with a group of initial purchasers ("Initial Purchasers") pursuant to which the Company agreed to issue $250.0 million in aggregate principal amount of the Company's senior notes due 2017 ("2017 Notes"). The 2017 Notes were offered and sold to the Initial Purchasers and then resold to qualified institutional buyers, each in transactions exempt from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"). The Company used the net proceeds (after deducting the Initial Purchasers' discounts and offering expenses) of approximately $230.8 million to reduce indebtedness under its Credit Facility. In connection with the 2017 Notes, the Company incurred financing fees and expenses of approximately $6.9 million, which will be amortized over the life of the 2017 Notes; the expense is recorded in "interest expense, net of amounts capitalized" on the consolidated statements of operations. The $12.3 million discount on the 2017 Notes will be amortized over the life of the 2017 Notes; the expense is recorded in "interest expense, net of amounts capitalized" on the consolidated statements of operations.

The 2017 Notes were issued under an Indenture dated May 18, 2009, ("Indenture"), mature May 15, 2017, and bear interest at 11.75%. Interest is payable semi-annually beginning November 15, 2009. The 2017 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 2017 Notes on a senior unsecured basis. The Indenture provides that the Company may redeem: (i) on or prior to May 15, 2011, up to 35% of the aggregate principal amount of the 2017 Notes at a redemption price of 111.75% of the principal amount, plus accrued and unpaid interest; (ii) prior to May 15, 2013, all or part of the 2017 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 May 15, 2013, all or part of the 2017 Notes at redemption prices equal to 105.875% in 2013, 102.938% in 2014 and 100% in 2015 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 2017 Notes at a redemption price equal to 101%, plus accrued and unpaid interest.

The 2017 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. The Company is in compliance with all financial and other covenants of the 2017 Notes.

In connection with the issuance and sale of the 2017 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 2017 Notes in exchange for outstanding 2017 Notes. In certain circumstances, the Company may be required to file a shelf registration statement to cover resales of the 2017 Notes. The Company will not be obligated to file the registration statements described above if the restrictive legend on the 2017 Notes has been removed and the 2017 Notes are freely tradable (in each case, other than with respect to persons that are affiliates of the Company) pursuant to Rule 144 of the Securities Act, as of the 366th day after the 2017 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 2017 Notes under certain circumstances.

Senior Notes Due 2018

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 ("2018 Notes"). The 2018 Notes were offered and sold to the Initial Purchasers and then resold to qualified institutional buyers, each in transactions exempt from the registration requirements of the Securities Act. The Company used the net proceeds (after deducting the

Initial Purchasers' discounts and offering expenses) of approximately $243.6 million to repay an outstanding term loan. In connection with the 2018 Notes, the Company incurred financing fees and expenses of approximately $7.8 million, which will be amortized over the life of the 2018 Notes; the expense is recorded in "interest expense, net of amounts capitalized" on the consolidated statements of operations. The $5.9 million discount on the 2018 Notes will be amortized over the life of the 2018 Notes; the expense is recorded in "interest expense, net of amounts capitalized" on the consolidated statements of operations.

The 2018 Notes were issued under an Indenture dated June 27, 2008, ("Indenture"), mature July 1, 2018, and bear interest at 9.875%. Interest is payable semi-annually beginning January 1, 2009. The 2018 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 2018 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 2018 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 2018 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 2018 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 2018 Notes at a redemption price equal to 101%, plus accrued and unpaid interest.

The 2018 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. The Company is in compliance with all financial and other covenants of the 2018 Notes. In June 2009, the Company instructed the trustee to remove the restrictive legend from the 2018 Notes making them freely tradable (other than with respect to persons that are affiliates of the Company). This terminated the Company's obligations under a registration rights agreement entered into in connection with issuance of the 2018 Notes.

(7) Derivatives

Commodity Derivatives

The Company sells oil, natural gas and NGL in the normal course of its business and utilizes derivative instruments to minimize the variability in cash flow due to commodity price movements. The Company enters into derivative instruments such as swap contracts, put options and collars to economically hedge its forecasted oil, natural 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; therefore, the changes in fair value of these instruments are recorded in current earnings. See Note 8 for fair value disclosures about oil and natural gas commodity derivatives.

The following table summarizes open positions as of December 31, 2009, and represents, as of such date, derivatives in place through December 31, 2013, on annual production volumes:

	Year 2010	Year 2011	Year 2012	Year 2013
Natural gas positions:				
Fixed price swaps:				
Hedged volume (MMMBtu)	39,566	31,901	—	—
Average price ($/MMBtu)	$ 8.90	$ 9.50	$ —	$ —
Puts:				
Hedged volume (MMMBtu)	6,960	6,960	—	—
Average price ($/MMBtu)	$ 8.50	$ 9.50	$ —	$ —
PEPL puts: (1)				
Hedged volume (MMMBtu)	10,634	13,259	—	—
Average price ($/MMBtu)	$ 7.85	$ 8.50	$ —	$ —
Total:				
Hedged volume (MMMBtu)	57,160	52,120	—	—
Average price ($/MMBtu)	$ 8.66	$ 9.25	$ —	$ —
Oil positions:				
Fixed price swaps: (2)				
Hedged volume (MBbls)	2,150	2,073	732	730
Average price ($/Bbl)	$ 90.00	$ 90.00	$ 100.00	$ 100.00
Puts: (3)				
Hedged volume (MBbls)	2,250	2,352	—	—
Average price ($/Bbl)	$ 110.00	$ 75.00	$ —	$ —
Collars:				
Hedged volume (MBbls)	250	276	—	—
Average floor price ($/Bbl)	$ 90.00	$ 90.00	$ —	$ —
Average ceiling price ($/Bbl)	$ 112.00	$ 112.25	$ —	$ —
Total:				
Hedged volume (MBbls)	4,650	4,701	732	730
Average price ($/Bbl)	$ 99.68	$ 82.50	$ 100.00	$ 100.00
Natural gas basis differential positions:				
PEPL basis swaps: (1)				
Hedged volume (MMMBtu)	43,166	35,541	34,066	31,700
Hedged differential ($/MMBtu)	$ (0.97)	$ (0.96)	$ (0.95)	$ (1.01)

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

(2) As presented in the table above, the Company has outstanding fixed price oil swaps on 2,000 Bbls per day at a price of $100.00 per Bbl for the years ending December 31, 2012, and December 31, 2013. The Company has derivative contracts that extend the swaps for each of the years ending December 31, 2014, December 31, 2015, and December 31, 2016, if the counterparties determine that the strike prices are in-the-money on a designated date in each respective preceding year. The extension for each year is exercisable without respect to the other years.

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

Settled derivatives on natural gas production for the year ended December 31, 2009, included a volume of 51,880 MMMBtu at an average contract price of $8.32. Settled derivatives on oil and NGL production for the year ended December 31, 2009, included a volume of 4,530 MBbls at an average contract price of

$102.21. The natural gas derivatives are settled based on the closing NYMEX future price of natural gas or on the published PEPL spot price of natural gas on the settlement date, which occurs on the third day preceding the production month. The oil derivatives are settled based on the month's average daily NYMEX price of light oil and settlement occurs on the final day of the production month.

In February 2010, the Company entered into fixed price oil swaps on an additional 5,250 Bbls per day at a price of $100.00 per Bbl for the years ending December 31, 2012, and December 31, 2013. The Company has derivative contracts that extend the swaps for each of the years ending December 31, 2014, December 31, 2015, and December 31, 2016, if the counterparties determine that the strike prices are in-the-money on a designated date in each respective preceding year. The extension for each year is exercisable without respect to the other years.

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 to pay the counterparty the difference, and conversely, the counterparty is 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; therefore, the changes in fair value of these instruments are recorded in current earnings. See Note 8 for fair value disclosures about interest rate swaps.

The following presents the settlement terms of the interest rate swaps at December 31, 2009:

	Year 2010	Year 2011	Year 2012	Year 2013 [1]
		(dollars in thousands)		
Notional amount	$ 1,212,000	$ 1,212,000	$ 1,212,000	$ 1,212,000
Fixed rate	3.85%	3.85%	3.85%	3.85%

[1] Actual settlement term is through January 6, 2014.

Outstanding Notional Amounts

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

	December 31, 2009	December 31, 2008
Outstanding notional amounts of natural gas contracts (MMMBtu)	109,280	196,756
Maximum number of months natural gas contracts outstanding	24	48
Outstanding notional amounts of oil contracts (MBbls)	10,813	21,229
Maximum number of months oil contracts outstanding	48	72
Outstanding notional amount of interest rate swaps (in thousands)	$ 1,212,000	$ 1,212,000
Maximum number of months interest rate swaps outstanding	48	24

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,	
	2009	2008
	(in thousands)	
Assets:		
Commodity derivatives	$ 549,879	$ 977,847
Interest rate swaps	2,603	—
	$ 552,482	$ 977,847
Liabilities:		
Commodity derivatives	$ 192,573	$ 119,124
Interest rate swaps	69,644	82,422
	$ 262,217	$ 201,546

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 or affiliates of participants in its Credit Facility (see Note 6), which is secured by the Company's oil and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not require collateral from its 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 $552.5 million at December 31, 2009. 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 meet the Company's minimum credit quality standard, or have a guarantee from an affiliate that meets 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 derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of such loss is somewhat mitigated.

Gain (Loss) on Derivatives

Gains and losses on derivatives are reported on the consolidated statements of operations in "gain (loss) on oil and natural gas derivatives" and "gain (loss) on interest rate swaps" and include realized and unrealized gains (losses). Realized gains (losses), excluding canceled 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 noncash items.

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

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Realized gains (losses):			
Commodity derivatives	$ 400,968	$ 9,408	$ 37,250
Interest rate swaps	(42,881)	(16,036)	1,467
Canceled derivatives	48,977	(81,358)	—
	$ 407,064	$ (87,986)	$ 38,717
Unrealized gains (losses):			
Commodity derivatives	$ (591,379)	$ 734,732	$ (382,787)
Interest rate swaps	16,588	(50,638)	(29,548)
	$ (574,791)	$ 684,094	$ (412,335)
Total gains (losses):			
Commodity derivatives	$ (141,374)	$ 662,782	$ (345,537)
Interest rate swaps	(26,353)	(66,674)	(28,081)
	$ (167,727)	$ 596,108	$ (373,618)

During the year ended December 31, 2009, the Company canceled (before the contract settlement date) derivative contracts on estimated future oil and natural gas production resulting in realized net gains of approximately $49.0 million. Of this amount, realized net gains of approximately $44.8 million, along with an incremental premium payment of approximately $48.8 million, were used to reposition the Company's commodity derivative portfolio in July 2009 when the Company canceled oil and natural gas derivative contracts for years 2012 through 2014 to raise prices for oil and natural gas derivative contracts in years 2010 and 2011.

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

(8) Fair Value Measurements on a Recurring Basis

The Company accounts for its commodity and interest rate derivatives at fair value (see Note 7) on a recurring basis. The fair value of derivative instruments is determined utilizing pricing models for significantly similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to the Company's commodity and interest rate derivatives.

Fair Value Hierarchy

In accordance with applicable accounting standards, 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 sheets 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.

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 fair value hierarchy for assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurements on a Recurring Basis December 31, 2009		
	Level 2	**Netting** (1)	**Total**
		(in thousands)	
Assets:			
Commodity derivatives	$ 549,879	$ (154,666)	$ 395,213
Interest rate swaps	$ 2,603	$ (2,603)	$ —
Liabilities:			
Commodity derivatives	$ 192,573	$ (154,666)	$ 37,907
Interest rate swaps	$ 69,644	$ (2,603)	$ 67,041

(1) Represents counterparty netting under agreements governing such derivatives.

(9) Other Property and Equipment

Other property and equipment consists of the following:

	December 31, 2009	December 31, 2008
	(in thousands)	
Natural gas compression plant and pipeline	$ 88,765	$ 87,133
Buildings and leasehold improvements	9,213	7,734
Vehicles	7,005	5,840
Drilling and other equipment	1,313	1,566
Furniture and office equipment	11,929	8,338
Land	642	848
	118,867	111,459
Less accumulated depreciation	(23,583)	(13,171)
	$ 95,284	$ 98,288

(10) Asset Retirement Obligations

Asset retirement obligations 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 and are included in "other noncurrent liabilities" on the consolidated balance sheets. Accretion expense is included in "depreciation, depletion and amortization" on the consolidated statements of operations. The fair value of additions to the asset retirement obligation liability is estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plug and abandon costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors (2.0% for each of the years in the three-year period ended December 31, 2009); and (iv) a credit-adjusted risk-free interest rate (average of 9.6%, 7.8% and 7.0% for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, respectively).

Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including, in addition to those noted above, the ultimate settlement amounts, 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 asset retirement obligation liability, a corresponding adjustment is made to the asset balance.

The following presents a reconciliation of the asset retirement obligation liability:

	December 31, 2009	December 31, 2008
	(in thousands)	
Asset retirement obligations at beginning of year	$ 28,922	$ 29,073
Liabilities added from acquisitions	1,350	5,398
Liabilities added from drilling	66	541
Liabilities associated with assets sold	—	(8,020)
Current year accretion expense	2,324	1,967
Settlements	(577)	(37)
Revision of estimates	1,050	—
Asset retirement obligations at end of year	$ 33,135	$ 28,922

(11) Commitments and Contingencies

On September 15, 2008, Lehman Brothers Holdings Inc. ("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 Brothers Commodity Services Inc. ("Lehman Commodity Services") also filed a voluntary petition for reorganization under Chapter 11 with the Court. At December 31, 2009, and December 31, 2008, the Company had a net receivable of approximately $6.7 million from Lehman Commodity Services for canceled derivative contracts, which is included in "other current assets" on the consolidated balance sheets. The value of the receivable was estimated based on market expectations. The Company is pursuing various legal remedies to protect its interests and 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.

(12) Earnings Per Unit

Effective January 1, 2009, the Company adopted an accounting standard that requires unvested restricted units to be included in the computation of earnings per unit under the two-class method. The adoption required retrospective adjustment of all prior period earnings per unit data. The impact of the adoption was a reduction to income from continuing operations per unit – diluted and net income per unit – diluted, of $0.05 per unit for the year ended December 31, 2008. There was no impact for the year ended December 31, 2007.

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. Diluted earnings per unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. The Company uses the treasury stock method to determine the dilutive effect.

The following table provides a reconciliation of the numerators and denominators of the basic and diluted per unit computations for income (loss) from continuing operations:

	Income (Loss) (Numerator)	Units (Denominator)	Per Unit Amount
	(in thousands)		
Year ended December 31, 2009:			
Loss from continuing operations:			
Allocated to units	$ (295,841)		
Allocated to unvested restricted units	—		
	$ (295,841)		
Loss per unit:			
Basic loss per unit		119,307	$ (2.48)
Dilutive effect of unit equivalents		—	—
Diluted loss per unit		119,307	$ (2.48)
Year ended December 31, 2008:			
Income from continuing operations:			
Allocated to units	$ 825,657		
Allocated to unvested restricted units	(5,610)		
	$ 820,047		
Income per unit:			
Basic income per unit		114,140	$ 7.18
Dilutive effect of unit equivalents		18	—
Diluted income per unit		114,158	$ 7.18
Year ended December 31, 2007:			
Loss from continuing operations:			
Allocated to units	$ (356,194)		
Allocated to unvested restricted units	—		
	$ (356,194)		
Loss per unit:			
Basic loss per unit		68,916	$ (5.17)
Dilutive effect of unit equivalents		—	—
Diluted loss per unit		68,916	$ (5.17)

Basic units outstanding excludes the effect of weighted average anti-dilutive unit equivalents related to 2.1 million, 1.7 million and 1.2 million unit options and warrants for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, respectively. All equivalent units were anti-dilutive for the years ended December 31, 2009, and December 31, 2007.

(13) Operating Leases

The Company leases office space and other property and equipment under lease agreements expiring on various dates through 2019. The Company recognized expense under operating leases of approximately \$3.6 million, \$3.2 million and \$1.2 million for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, respectively.

As of December 31, 2009, future minimum lease payments were as follows (in thousands):

2010	$ 3,954
2011	4,084
2012	3,727
2013	3,251
2014	3,275
Thereafter	11,674
	$ 29,965

(14) Income Taxes

The Company is a limited liability company 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 passed through to unitholders. Limited liability companies are subject to state income taxes in Texas. As such, with the exception of the state of Texas, 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 set forth in the tables below.

The Company's taxable income or loss, which may vary substantially from the net income or net loss reported in the consolidated statements 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 federal and state income taxes. Income tax benefit (expense) from continuing operations consisted of the following:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Current taxes:			
Federal	$ (1,063)	$ (1,184)	$ (1,355)
State	(678)	(1,528)	(283)
Deferred taxes:			
Federal	5,307	—	(3,066)
State	655	—	(84)
	$ 4,221	$ (2,712)	$ (4,788)

As of December 31, 2009, the Company's taxable entities had approximately $3.0 million of net operating loss carryforwards for federal income tax purposes, which will begin expiring in 2025.

Income tax benefit (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,		
	2009	2008	2007
Federal statutory rate	35.0%	35.0%	35.0%
State, net of federal tax benefit	—	0.1	(0.1)
Income or loss excluded from nontaxable entities	(34.3)	(34.9)	(35.3)
Nondeductible compensation	—	—	(0.3)
Other items	0.7	0.1	(0.7)
Effective rate	1.4%	0.3%	(1.4)%

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

	December 31,	
	2009	2008
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 1,175	$ 2,767
Unit-based compensation	7,166	5,617
Other	1,924	897
Valuation allowance	(1,223)	(7,132)
Total deferred tax assets	9,042	2,149
Deferred tax liabilities:		
Property and equipment principally due to differences in depreciation	(2,284)	(2,149)
Other	(322)	—
Total deferred tax liabilities	(2,606)	(2,149)
Net deferred tax assets (liabilities)	$ 6,436	$ —

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

	December 31,	
	2009	2008
	(in thousands)	
Other current assets – deferred tax assets	$ 5,372	$ —
Deferred tax assets	$ 3,670	$ 2,149
Deferred tax liabilities	(2,606)	(2,149)
Other noncurrent assets	$ 1,064	$ —

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 more likely than not that the

Company will realize the benefits of the majority of these deductible differences at December 31, 2009. The Company has recorded a valuation allowance against certain deferred tax assets. The amount of deferred tax assets considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

In accordance with the applicable accounting standard, the Company recognizes 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. 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. It is the Company's policy to recognize interest and penalties, if any, related to unrecognized tax benefits in income tax expense. The Company had no material uncertain tax positions at December 31, 2009, or December 31, 2008.

(15) 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 during that time frame. Lehman Holdings' subsidiaries provided certain services to the Company, including participation in the Company's Credit Facility, offering of 2018 Notes (see Note 6), sale of Appalachian Basin assets (see Note 2) and sale of commodity derivative instruments (see Note 7), 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 11 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 year 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 the year ended December 31, 2008 (through July 3), the Company purchased approximately $1.3 million of deal contingent commodity swap contracts from Lehman. In addition, during the year ended December 31, 2007, the Company paid Lehman approximately $226.3 million for commodity derivative contracts.

Other

During the years ended December 31, 2008, and December 31, 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 natural gas and are primarily included in "natural gas marketing expenses" on the consolidated statements of operations. The transactions were consummated on terms equivalent to those that prevail in arm's-length transactions.

Eric P. Linn, brother of the Company's Executive Chairman, 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. During the year ended December 31, 2008, the Company made payments of approximately $0.2 million to Mr. Linn under the Severance Agreement and Release. The payments are included in "income (loss) from discontinued operations, net of taxes" on the consolidated statements of operations. The transaction was consummated on terms equivalent to those that prevail in arm's-length transactions.

(16) Supplemental Disclosures to the Consolidated Balance Sheets and Consolidated Statements of Cash Flows

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

	December 31,	
	2009	2008
	(in thousands)	
Accrued compensation	$ 14,378	$ 11,366
Accrued interest	18,332	14,232
Other	1,212	1,565
	$ 33,922	$ 27,163

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

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Cash payments for interest, net of amounts capitalized	$ 73,861	$ 94,958	$ 57,348
Cash payments for income taxes	$ 1,282	$ 452	$ —
Noncash investing activities:			
In connection with the acquisition of oil and natural gas properties, liabilities were assumed as follows:			
Fair value of assets acquired	$ 117,717	$ 602,858	$ 2,710,417
Cash paid	(115,285)	(593,412)	(2,649,965)
Receivable from seller	636	—	—
Liabilities assumed	$ 3,068	$ 9,446	$ 60,452
Noncash financing activities:			
Units issued in connection with the acquisition of oil and natural gas properties	$ —	$ 23,455	$ 2,600

(17) Recently Issued Pronouncements

Codification

In June 2009, the Financial Accounting Standards Board ("FASB") approved the FASB Accounting Standards Codification ("Codification" or "ASC"), effective for financial statements for interim or annual reporting periods ending after September 15, 2009. The Codification is the single source of authoritative nongovernmental GAAP, superseding existing FASB, American Institute of Certified Public Accountants, Emerging Issues Task Force and related literature. References herein to prior GAAP standards that were used to create the Codification have been replaced or supplemented with references to the relevant section of the Codification and are identified as "FASB ASC" or "ASC Update."

Accounting Standards

In August 2009, the FASB issued ASC Update 2009-5, *"Fair Value Measurements and Disclosures (Topic 820) – Measuring Liabilities at Fair Value,"* which includes amendments to Subtopic 820-10, *"Fair Value Measurements and Disclosures – Overall,"* for the fair value measurement of liabilities and provides clarification that in circumstances in which a quoted price in an active market for the identical liability is not available, an entity is required to measure fair value using one or more of the techniques provided for in this update, including the quoted price of the liability when traded as an asset. The guidance in this update is effective for interim and annual periods ending after September 30, 2009, and the Company adopted it effective October 1, 2009. The adoption did not have a material impact on the Company's results of operations or financial position.

In May 2009, the FASB issued FASB ASC 855, *"Subsequent Events,"* and in February 2010, the FASB issued ASC Update 2010-09, *"Subsequent Events (Topic 855) – Amendments to Certain Recognition and Disclosure Requirements,"* which establishes standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. Under this standard, entities that file or furnish financial statements with the SEC, such as the Company, are required to use an issued date in evaluating subsequent events. This standard, as updated, is effective February 24, 2010, and the Company adopted it at that date. The adoption did not have a material impact on the Company's results of operations or financial position.

In April 2009, the FASB issued three related standards to clarify the application of FASB ASC 820 "*Fair Value Measurements and Disclosures,*" to fair value measurements in the current economic environment, modify the recognition of other-than-temporary impairments of debt securities, and require companies to disclose the fair value of financial instruments in interim periods. The final standards are effective for interim and annual periods ending after June 15, 2009, and the Company adopted the new standards effective June 30, 2009. The adoption did not have a material impact on the Company's results of operations or financial position. The three related standards are as follows:

> FASB ASC 820-10-65-4, "*Transition Related to FASB Staff Position FAS 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,*" provides guidance on how to determine the fair value of assets and liabilities under FASB ASC 820 in the current economic environment and reemphasizes that the objective of a fair value measurement remains the price that would be received to sell an asset or paid to transfer a liability at the measurement date.
>
> FASB ASC 320-10-65-1, "*Transition Related to FSP FAS 115-2 and FAS 124-2, Recognition and Presentation of Other-Than-Temporary Impairments,*" modifies the requirements for recognizing other-than-temporarily impaired debt securities and significantly changes the existing impairment model for such securities. It also modifies the presentation of other-than-temporary impairment

losses and increases the frequency of and expands already required disclosures about other-than-temporary impairment for debt and equity securities.

FASB ASC 825-10-65-1, *"Transition Related to FSP FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments,"* requires disclosures of the fair value of financial instruments within the scope of FASB ASC 825, *"Financial Instruments,"* in interim financial statements, adding to the current requirement to make those disclosures in annual financial statements. It also requires that companies disclose the method or methods and significant assumptions used to estimate the fair value of financial instruments and a discussion of changes, if any, in the method or methods and significant assumptions during the period.

FASB ASC 805, *"Business Combinations,"* issued in December 2007, with additional guidance issued in April 2009, requires an acquiring entity to recognize all assets acquired and liabilities assumed at fair value with limited exceptions. Assets acquired and liabilities assumed that arise from contingencies are to be recognized at fair value if fair value can be reasonably estimated. If fair value of such an asset or liability cannot be reasonably estimated, the asset or liability should generally be recognized in accordance with FASB ASC 450, *"Contingencies."* This standard changes the accounting treatment for certain specific items, including acquisition costs, which are expensed as incurred, and also includes new disclosure requirements. This standard 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. The Company adopted this standard effective January 1, 2009, (see Note 2).

FASB ASC 820, *"Fair Value Measurements and Disclosures,"* issued in September 2006, provides guidance for using fair value to measure assets and liabilities. This standard 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. The Company adopted the provisions of this standard related to financial assets and liabilities and nonfinancial assets and liabilities measured on a recurring basis effective January 1, 2008, and related to nonfinancial assets and liabilities measured on a nonrecurring basis effective January 1, 2009, (see Note 2 and Note 10). There was no impact from the adoption related to items measured on a nonrecurring basis.

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

The following discussion and analysis should be read in conjunction with the "Consolidated Financial Statements" and "Notes to Consolidated Financial Statements," which are included in this Annual Report on Form 10-K in Item 8. "Financial Statements and Supplementary Data." The Company's Appalachian Basin and Mid Atlantic operations have been classified as discontinued operations on the consolidated statements of operations for all periods presented (see Note 2). Unless otherwise indicated, information presented in the following supplemental oil and natural gas data has been recast to present continuing operations separately from discontinued operations.

(A) Modernization of Oil and Natural Gas Reporting Requirements

Effective for fiscal years ending on or after December 31, 2009, the SEC approved revisions designed to modernize reserve reporting requirements for oil and natural gas companies. In addition, effective for the same period, the FASB issued ASC Update 2010-03, "*Extractive Activities – Oil and Gas (Topic 932) – Oil and Gas Reserve Estimation and Disclosures*," to provide consistency with the new SEC rules. The most significant amendments to the requirements include the following:

- commodity prices – economic producibility of reserves estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions;
- 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
- nontraditional resources – the definition of oil and natural gas producing activities were expanded and focus on the marketable product rather than the method of extraction.

The Company adopted the new requirements effective December 31, 2009. The adoption did not have a material impact on the Company's results of operations or financial position. The impact of adoption due to the estimation of reserves using the average price instead of the year-end price was a material reduction in estimated quantity and value of reserves at December 31, 2009, of approximately 195 Bcfe, or $1.50 billion. There were no other significant impacts of adoption.

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

Costs incurred in oil and natural gas property acquisition, exploration and development, whether capitalized or expensed, are presented below:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Property acquisition costs: [1]			
Proved	$ 115,929	$ 595,795	$ 2,422,983
Unproved	947	4,111	148,284
Exploration costs	337	—	—
Development costs	140,892	332,557	189,466
Total costs incurred	$ 258,105	$ 932,463	$ 2,760,733
Costs incurred – continuing operations	$ 258,105	$ 900,256	$ 2,674,439
Costs incurred – discontinued operations	$ —	$ 32,207	$ 86,294

[1] See Note 2 for details about the Company's acquisitions.

(C) Oil and Natural Gas Capitalized Costs

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

	December 31, 2009	December 31, 2008
	(in thousands)	
Proved properties:		
Leasehold acquisition	$ 3,398,292	$ 3,278,155
Development	600,436	460,730
Unproved properties	78,067	92,298
	4,076,795	3,831,183
Less accumulated depletion and amortization	(463,413)	(278,805)
	$ 3,613,382	$ 3,552,378

(D) Results of Oil and Natural Gas Producing Activities

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

	Year Ended December 31, 2009	2008	2007
		(in thousands)	
Revenues and other:			
Oil, natural gas and natural gas liquid sales	$ 408,219	$ 755,644	$ 255,927
Gain (loss) on oil and natural gas derivatives	(141,374)	662,782	(345,537)
	266,845	1,418,426	(89,610)
Production costs:			
Lease operating expenses	132,647	115,402	41,946
Transportation expenses	18,202	17,597	5,575
Production and ad valorem taxes	28,687	59,598	20,295
	179,536	192,597	67,816
Other costs:			
Exploration costs	7,169	7,603	4,053
Depletion and amortization	191,314	185,857	64,857
Impairment of goodwill and long-lived assets	—	50,505	—
Texas margin tax expense	490	920	—
(Gain) loss on sale of assets and other, net	(25,710)	(99,050)	—
	173,263	145,835	68,910
Results of continuing operations	$ (85,954)	$ 1,079,994	$ (226,336)
Results of discontinued operations	$ (238)	$ 190,915	$ 19,111

There is no federal tax provision included in the results above because the Company's subsidiaries subject to federal tax do not own any of the Company's oil and natural gas interests. Limited liability companies are subject to state income taxes in Texas (see Note 14). Discontinued operations activity for 2009 primarily represents activity related to post-closing adjustments for the sale of properties in the Appalachian Basin (see Note 2).

(E) Proved Oil, Natural Gas and NGL Reserves

The proved reserves of oil, natural gas and NGL of the Company have been prepared by the independent engineering firm DeGolyer and MacNaughton. In accordance with revised SEC regulations (see Note A), reserves at December 31, 2009, were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. In accordance with SEC regulations, reserves for all prior years were estimated using year-end prices. An analysis of the change in estimated quantities of oil, natural gas and NGL reserves, all of which are located within the United States, is shown below:

	Year Ended December 31, 2009			
	Natural Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of year	851,232	84,144	50,722	1,660,428
Revisions of previous estimates	(69,347)	10,868	3,904	19,280
Purchase of minerals in place	6,825	8,757	386	61,684
Extensions, discoveries and other additions	31,479	1,648	1,508	50,416
Production	(45,710)	(3,287)	(2,358)	(79,580)
End of year	774,479	102,130	54,162	1,712,228
Proved developed reserves:				
Beginning of year	585,071	61,884	29,600	1,133,976
End of year	549,218	77,878	33,898	1,219,876
Proved undeveloped reserves:				
Beginning of year	266,161	22,260	21,122	526,452
End of year	225,261	24,252	20,264	492,352

	Year Ended December 31, 2008					
	Natural 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
Proved undeveloped reserves:						
Beginning of year	217,281	11,960	17,578	394,507	49,458	443,965
End of year	266,161	22,260	21,122	526,452	—	526,452

	Year Ended December 31, 2007					
	Natural 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
Proved undeveloped reserves:						
Beginning of year	27,892	5,335	—	59,903	80,106	140,009
End of year	217,281	11,960	17,578	394,507	49,458	443,965

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 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 about the Company's acquisitions and divestitures.

Proved reserves increased by approximately 52 Bcfe, to approximately 1,712 Bcfe for the year ended December 31, 2009, from 1,660 Bcfe for the year ended December 31, 2008. The year ended December 31, 2009, includes 19 Bcfe in positive revisions of previous estimates, due primarily to higher asset performance, which contributed approximately 38 Bcfe, most significantly related to well reactivations and waterflood optimization work in the Mid-Continent Shallow region. These positive revisions were partially offset by 19 Bcfe in negative revisions primarily due to decreases in natural gas prices. Two acquisitions during the year ended December 31, 2009, increased proved reserves by approximately 62 Bcfe. In addition, extensions and discoveries, primarily from 72 productive wells drilled during the year, contributed approximately 50 Bcfe to the increase in proved reserves.

Proved reserves related to continuing operations increased by approximately 241 Bcfe, to approximately 1,660 Bcfe for the year ended December 31, 2008, from 1,419 Bcfe for the year ended December 31, 2007. Substantially all of the 228 Bcfe in negative revisions of previous estimates was due to decreases in oil and natural gas prices. Four acquisitions during the year ended December 31, 2008, increased proved reserves by approximately 368 Bcfe. In addition, extensions and discoveries, primarily from 304 productive wells drilled during the year, contributed approximately 228 Bcfe to the increase in proved reserves. The sale of properties located in the Verden area of Oklahoma decreased proved reserves by approximately 49 Bcfe.

Proved reserves related to continuing operations increased by approximately 1,164 Bcfe, to approximately 1,419 Bcfe for the year ended December 31, 2007, from 255 Bcfe for the year ended December 31, 2006. Six acquisitions during the year ended December 31, 2007, increased proved reserves by approximately 1,071 Bcfe. In addition, extensions and discoveries, primarily from 136 productive wells drilled during the year, contributed approximately 91 Bcfe to the increase in proved reserves.

(F) 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 applicable 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 14).

	December 31, 2009	December 31, 2008	December 31, 2007
		(in thousands)	
Future estimated revenues	$ 10,093,876	$ 8,261,234	$ 12,565,382
Future estimated production costs	(4,200,091)	(3,410,684)	(3,052,847)
Future estimated development costs	(816,577)	(896,625)	(582,890)
Future net cash flows	5,077,208	3,953,925	8,929,645
10% annual discount for estimated timing of cash flows	(3,353,926)	(2,529,558)	(5,754,798)
Standardized measure of discounted future net cash flows – continuing operations	$ 1,723,282	$ 1,424,367	$ 3,174,847
Standardized measure of discounted future net cash flows – discontinued operations	$ —	$ —	$ 283,392
Representative NYMEX prices: (1)			
Natural gas (MMBtu)	$ 3.87	$ 5.71	$ 6.80
Oil (Bbl)	$ 61.05	$ 39.22	$ 95.92

(1) In accordance with SEC regulations, reserves at December 31, 2009, were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. In accordance with SEC regulations, reserves for all prior years were estimated using year-end prices.

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

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

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Sales and transfers of oil, natural gas and NGL produced during the period	$ (228,683)	$ (563,047)	$ (188,111)
Changes in estimated future development costs	54,141	32,006	6,271
Net change in sales and transfer prices and production costs related to future production	254,036	(2,837,262)	81,654
Purchase of minerals in place	128,779	1,066,615	2,438,178
Sale of minerals in place	—	(102,437)	—
Extensions, discoveries, and improved recovery	25,888	383,017	172,989
Previously estimated development costs incurred during the period	52,699	76,150	69,221
Net change due to revisions in quantity estimates	23,672	(69,044)	56,154
Accretion of discount	142,437	317,485	29,876
Changes in production rates and other	(154,054)	(53,963)	209,855
Change – continuing operations	$ 298,915	$ (1,750,480)	$ 2,876,087
Change – discontinued operations	$ —	$ (283,392)	$ 29,892

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.

LINN ENERGY, LLC
SUPPLEMENTAL QUARTERLY DATA (Unaudited)

The following discussion and analysis should be read in conjunction with the "Consolidated Financial Statements" and "Notes to Consolidated Financial Statements," which are included in this Annual Report on Form 10-K in Item 8. "Financial Statements and Supplementary Data."

(A) Quarterly Financial Data

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per unit amounts)			
2009:				
Oil, natural gas and natural gas liquid sales	$ 79,864	$ 91,906	$ 102,989	$ 133,460
Gain (loss) on oil and natural gas derivatives	$ 161,315	$ (232,775)	$ (14,065)	$ (55,849)
Total revenues and other	$ 242,661	$ (139,045)	$ 90,425	$ 79,108
Total expenses [(1)]	$ 121,576	$ 117,295	$ 116,339	$ 120,884
(Gain) loss on sale of assets and other, net	$ (26,711)	$ (5)	$ 1,999	$ 119
Income (loss) from continuing operations	$ 121,287	$ (268,701)	$ (82,462)	$ (65,965)
Income (loss) from discontinued operations, net of taxes [(2)]	$ (1,886)	$ 229	$ (1,247)	$ 553
Net income (loss)	$ 119,401	$ (268,472)	$ (83,709)	$ (65,412)
Income (loss) per unit – continuing operations:				
Basic	$ 1.06	$ (2.31)	$ (0.69)	$ (0.52)
Diluted	$ 1.06	$ (2.31)	$ (0.69)	$ (0.52)
Income (loss) per unit – discontinued operations:				
Basic	$ (0.02)	$ 0.01	$ (0.01)	$ 0.01
Diluted	$ (0.02)	$ 0.01	$ (0.01)	$ 0.01
Net income (loss) per unit:				
Basic	$ 1.04	$ (2.30)	$ (0.70)	$ (0.51)
Diluted	$ 1.04	$ (2.30)	$ (0.70)	$ (0.51)

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

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

LINN ENERGY, LLC
SUPPLEMENTAL QUARTERLY DATA (Unaudited) - Continued

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per unit amounts)			
2008:				
Oil, natural gas and natural gas liquid sales [(1)]	$ 175,872	$ 255,586	$ 240,634	$ 83,552
Gain (loss) on oil and natural 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 and other, 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: [(4)]				
Basic	$ (2.28)	$ (6.35)	$ 8.01	$ 7.72
Diluted	$ (2.28)	$ (6.35)	$ 8.01	$ 7.72
Income per unit – discontinued operations: [(4)]				
Basic	$ —	$ 0.12	$ 1.39	$ —
Diluted	$ —	$ 0.12	$ 1.39	$ —
Net income (loss) per unit: [(4)]				
Basic	$ (2.28)	$ (6.23)	$ 9.40	$ 7.72
Diluted	$ (2.28)	$ (6.23)	$ 9.40	$ 7.72

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

(2) Includes the following expenses: lease operating, transportation, natural 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.

(4) Effective January 1, 2009, the Company adopted an accounting standard requiring unvested restricted units to be included in the computation of earnings per unit under the two-class method. The adoption required retrospective adjustment of all prior period earnings per unit data. The impact of the adoption was a reduction to income from continuing operations per unit – diluted and net income per unit – diluted, of $0.04 per unit and $0.06 per unit, respectively, for the quarter ended September 30, 2008, and $0.04 for the quarter ended December 31, 2008. There was no impact for the quarters ended March 31, 2008, or June 30, 2008.

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, 2009.

Management's Annual Report on Internal Control Over Financial Reporting

See "Management's Report on Internal Control Over Financial Reporting" in Item 8. "Financial Statements and Supplementary Data."

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 2009 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

None.

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 in this Annual Report on Form 10-K under the caption "Executive Officers of the Company." 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 April 27, 2010 (the "2010 Proxy Statement"). That information is incorporated herein by reference.

The information in the 2010 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 2010 Proxy Statement under the caption "Corporate Governance."

Item 11. Executive Compensation

Information required by this item is incorporated herein by reference to the 2010 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 2010 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, 2009:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Unit Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Unit Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	1,947,843	$ 22.51	6,822,795
Equity compensation plans not approved by security holders	—	—	—
	1,947,843	$ 22.51	6,822,795

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

Information required by this item is incorporated herein by reference to the 2010 Proxy Statement.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated herein by reference to the 2010 Proxy Statement.

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 in Item 8. "Financial Statements and Supplementary Data" in this Annual Report on Form 10-K.

(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.

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 25, 2010

By: /s/ Mark E. Ellis
Mark E. Ellis
President and Chief Executive Officer

Date: February 25, 2010

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	Executive Chairman	February 25, 2010
/s/ Mark E. Ellis Mark E. Ellis	President and Chief Executive Officer (Principal Executive Officer)	February 25, 2010
/s/ Kolja Rockov Kolja Rockov	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2010
/s/ David B. Rottino David B. Rottino	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 25, 2010
/s/ George A. Alcorn George A. Alcorn	Independent Director	February 25, 2010
/s/ Terrence S. Jacobs Terrence S. Jacobs	Independent Director	February 25, 2010
/s/ Joseph P. McCoy Joseph P. McCoy	Independent Director	February 25, 2010
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Independent Director	February 25, 2010

INDEX TO EXHIBITS

Exhibit Number		Description
2.1†*	—	Asset Purchase and Sale Agreement, dated November 25, 2009, between Linn Energy Holdings, LLC and Merit Management Partners I, L.P., Merit Management Partners II, L.P., Merit Management Partners III, L.P., Merit Energy Partners III, L.P., Merit Energy Partners D-III, L.P., Merit Energy Partners E-III, L.P. and Merit Energy Partners F-III, L.P.
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 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	—	Indenture, dated May 18, 2009, 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 May 18, 2009)
4.4	—	Registration Rights Agreement, dated May 18, 2009, 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 May 18, 2009)
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)
10.2**	—	Amendment No. 1 to Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, dated February 4, 2009, (incorporated herein by reference to Exhibit 10.2 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.3**	—	Form of Executive Unit Option Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (incorporated herein by reference to Exhibit 10.3 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.4**	—	Form of Executive Restricted Unit Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (incorporated herein by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)

INDEX TO EXHIBITS - Continued

Exhibit Number		Description
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 (incorporated herein by reference to Exhibit 10.6 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.7**	—	Third Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Michael C. Linn (incorporated herein by reference to Exhibit 10.7 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.8**	—	Third Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Kolja Rockov (incorporated herein by reference to Exhibit 10.8 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.9**	—	Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Mark E. Ellis (incorporated herein by reference to Exhibit 10.9 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.10**	—	Amended and Restated Employment Agreement, dated effective December 17, 2008, between Linn Operating, Inc. and Charlene A. Ripley (incorporated herein by reference to Exhibit 10.10 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.11**	—	Amended and Restated Employment Agreement, dated effective December 17, 2008, between Linn Operating, Inc. and Arden L. Walker, Jr. (incorporated herein by reference to Exhibit 10.11 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.12**	—	Second Amended and Restated Employment Agreement, dated December 17, 2008, between Linn Operating, Inc. and David B. Rottino (incorporated herein by reference to Exhibit 10.12 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.13**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and George A. Alcorn (incorporated herein by reference to Exhibit 10.15 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.14**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Joseph P. McCoy (incorporated herein by reference to Exhibit 10.16 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.15**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Terrence S. Jacobs (incorporated herein by reference to Exhibit 10.17 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.16**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Jeffrey C. Swoveland (incorporated herein by reference to Exhibit 10.18 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.17**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Michael C. Linn (incorporated herein by reference to Exhibit 10.19 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.18**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Mark E. Ellis (incorporated herein by reference to Exhibit 10.20 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.19**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Kolja Rockov (incorporated herein by reference to Exhibit 10.21 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.20**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Charlene A. Ripley (incorporated herein by reference to Exhibit 10.22 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)

INDEX TO EXHIBITS - Continued

Exhibit Number		Description
10.21**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and David B. Rottino (incorporated herein by reference to Exhibit 10.23 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.22**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Arden L. Walker, Jr. (incorporated herein by reference to Exhibit 10.24 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.23**	—	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)
10.24	—	Fourth Amended and Restated Credit Agreement dated as of April 28, 2009, 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 May 7, 2009)
10.25	—	First Amendment, dated May 15, 2009, to Fourth 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 6, 2009)
10.26	—	Fourth Amended and Restated Guaranty and Pledge Agreement, dated as of April 28, 2009, 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 Quarterly Report on Form 10-Q filed on May 7, 2009)
10.27	—	Linn Energy, LLC Change of Control Protection Plan, dated as of April 25, 2009, (incorporated herein by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q filed on May 7, 2009)
10.28†**	—	Amendment No. 1, dated effective as of January 1, 2010, to Third Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Michael C. Linn
10.29†**	—	Amendment No. 1, dated effective as of January 1, 2010, to Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Mark E. Ellis
21.1†	—	Significant Subsidiaries of Linn Energy, LLC
23.1†	—	Consent of KPMG LLP
23.2†	—	Consent of DeGolyer and MacNaughton
31.1†	—	Section 302 Certification of Mark E. Ellis, 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 Mark E. Ellis, 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
99.1†	—	2009 Report of DeGolyer and MacNaughton

† 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.

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

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Linn Energy, LLC:

We consent to the incorporation by reference in the registration statements (No. 333-131153 and 333-151610) on Form S-8 and in the registration statements (No. 333-146120, 333-148061, 333-148134, 333-159125 and 333-162357) on Form S-3 of Linn Energy, LLC of our reports dated February 25, 2010, with respect to the consolidated balance sheets of Linn Energy, LLC as of December 31, 2009, and 2008, and the related consolidated statements of operations, unitholders' capital, and cash flows for each of the years in the three-year period ended December 31, 2009, and the effectiveness of internal control over financial reporting as of December 31, 2009, which reports appear in the December 31, 2009, annual report on Form 10-K of Linn Energy, LLC.

/s/ KPMG LLP

Houston, Texas
February 25, 2010

Exhibit 23.2

CONSENT OF DEGOLYER AND MACNAUGHTON

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton as independent petroleum engineers, and to the inclusion of information taken from our "Appraisal Report as of December 31, 2009 on Certain Properties owned by Linn Energy, LLC," "Appraisal Report as of December 31, 2008 on Certain Properties owned by Linn Energy, LLC" and "Appraisal Report as of December 31, 2007 on Certain Properties owned by Linn Energy, LLC" in the sections "Business," "Risk Factors," "Selected Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Supplemental Oil and Gas Data (Unaudited)" in the Linn Energy, LLC Annual Report on Form 10-K for the year ended December 31, 2009, and in the registration statement on Form S-8 (File No. 333-131153 and 333-151610), and the registration statements (Nos. 333-146120, 333-148061, 333-148134, 333-159125 and 333-162357) on Form S-3.

Very truly yours,

/s/ DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Dallas, Texas
February 25, 2010

Exhibit 31.1

I, Mark E. Ellis, certify that:

1. I have reviewed this Annual Report on Form 10-K of Linn Energy, LLC (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-5(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2010

/s/ Mark E. Ellis
Mark E. Ellis
President and Chief Executive Officer

Exhibit 31.2

I, Kolja Rockov, certify that:

1. I have reviewed this Annual Report on Form 10-K of Linn Energy, LLC (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-5(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2010

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

Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Linn Energy, LLC (the "Company") on Form 10-K for the year ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark E. Ellis, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Mark E. Ellis
Mark E. Ellis
President and Chief Executive Officer

Date: February 25, 2010

Exhibit 32.2

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Linn Energy, LLC (the "Company") on Form 10-K for the year ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Kolja Rockov, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

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

Date: February 25, 2010

RECONCILIATION OF NON-GAAP MEASURES

The Company defines adjusted EBITDA as income (loss) from continuing operations plus the following adjustments:

- Net operating cash flow from acquisitions and divestitures, effective date through closing date;
- Interest expense;
- Depreciation, depletion and amortization;
- Impairment of goodwill and long-lived assets;
- Write-off of deferred financing fees and other;
- (Gain) loss on sale of assets, net;
- Unrealized (gain) loss on commodity derivatives;
- Unrealized (gain) loss on interest rate derivatives;
- Realized (gain) loss on interest rate derivatives;
- Realized (gain) loss on canceled derivatives;
- Unit-based compensation expenses;
- Exploration costs; and
- Income tax (benefit) expense.

Adjusted EBITDA is a measure used by Company management to indicate (prior to the establishment of any reserves by its Board of Directors) the cash distributions the Company expects to pay unitholders. Adjusted EBITDA is also a quantitative measure used throughout the investment community with respect to publicly-traded partnerships and limited liability companies.

Adjusted net income is a performance measure used by Company management to evaluate its operational performance from oil and natural gas properties, prior to derivative gains and losses, impairment of goodwill and long-lived assets and (gain) loss on sale of assets, net.

For more information please refer to the Company's Annual Report on Form 10-K.

ADJUSTED EBITDA

The following presents a reconciliation of income (loss) from continuing operations to adjusted EBITDA:

(in thousands)	Year Ended December 31, 2009	2008
Income (loss) from continuing operations	($295,841)	$825,657
Plus:		
Net operating cash flow from acquisitions and divestitures, effective date through closing date (1)	3,708	3,436
Interest expense, cash	74,185	81,704
Interest expense, noncash	18,516	12,813
Depreciation, depletion and amortization	201,782	194,093
Impairment of goodwill and long-lived assets	-	50,505
Write-off of deferred financing fees and other	204	6,728
(Gain) loss on sale of assets, net	(23,051)	(98,763)
Unrealized (gain) loss on commodity derivatives	591,379	(734,732)
Unrealized (gain) loss on interest rate derivatives	(16,588)	50,638
Realized loss on interest rate derivatives (2)	42,881	16,036
Realized (gain) loss on canceled derivatives	(48,977)	81,358
Unit-based compensation expenses	15,089	14,699
Exploration costs	7,169	7,603
Income tax (benefit) expense	(4,221)	2,712
Adjusted EBITDA from continuing operations	$566,235	$514,487

(1) Includes net operating cash flow from acquisitions and divestitures.

(2) During 2009, the Company revised its definition of adjusted EBITDA to include realized (gains) losses on interest rate derivatives in order to match the related interest expense. All prior periods amounts have been reclassified to conform to current period presentation. This reclassification had no effect on the Company's reported net income.

ADJUSTED NET INCOME

The following presents a reconciliation of income (loss) from continuing operations to adjusted net income:

(in thousands, except per unit amounts)	Year Ended December 31, 2009	2008
Income (loss) from continuing operations	($295,841)	$825,657
Plus:		
Unrealized (gain) loss on commodity derivatives	591,379	(734,732)
Unrealized (gain) loss on interest rate derivatives	(16,588)	50,638
Realized (gain) loss on canceled derivatives	(48,977)	81,358
Impairment of goodwill and long-lived assets	-	50,505
(Gain) loss on sale of assets, net	(23,051)	(98,763)
Adjusted net income from continuing operations	$206,922	$174,663
Adjusted net income from continuing operations per unit – basic	$1.73	$1.52

RESERVE REPLACEMENT AND DEVELOPMENT CALCULATIONS

The reserve replacement metrics provided herein are non-GAAP financial measures. The methods used by the Company to calculate reserve replacement cost and finding and development cost may differ from methods used by other companies to compute similar measures. As a result, the Company's measures may not be comparable to similar measures provided by other companies. The Company believes that providing such measures is useful in evaluating the cost to add proved reserves; however, these measures should not be considered in isolation or as a substitute for GAAP measures, such as costs incurred in oil and natural gas property acquisition and development, contained in the Company's financial statements prepared in accordance with GAAP. The following presents the calculations of reserve replacement cost and finding and development cost from continuing operations:

	Year Ended December 31,	
	2009	**2008**
Costs incurred – continuing operations (in thousands):		
Costs incurred in oil and natural gas property acquisition, exploration and development	$ 258,105	$ 900,256
Less:		
Asset retirement obligation costs	(371)	(680)
Property acquisition costs	(115,929)	(584,630)
Oil and natural gas capital costs expended, excluding acquisitions	$ 141,805	$ 314,946
Reserve data – continuing operations (MMcfe):		
Purchase of minerals in place	61,684	368,136
Extensions, discoveries and other additions	50,416	228,083
Add:		
Revisions of previous estimates – other than price	38,665	(9,571)
Annual additions, excluding price-related revisions	150,765	586,648
Less:		
Purchase of minerals in place	(61,684)	(368,136)
Annual additions, excluding price-related revisions and acquisitions	89,081	218,512
Annual production – continuing operations (MMcfe)	79,580	77,548
Reserve replacement metrics – continuing operations:		
Reserve replacement cost per Mcfe (1)	$ 1.71	$ 1.53
Reserve replacement ratio (2)	189%	756%
Finding and development cost from the drillbit per Mcfe (3)	$ 1.59	$ 1.44
Drillbit reserve replacement ratio (4)	112%	282%

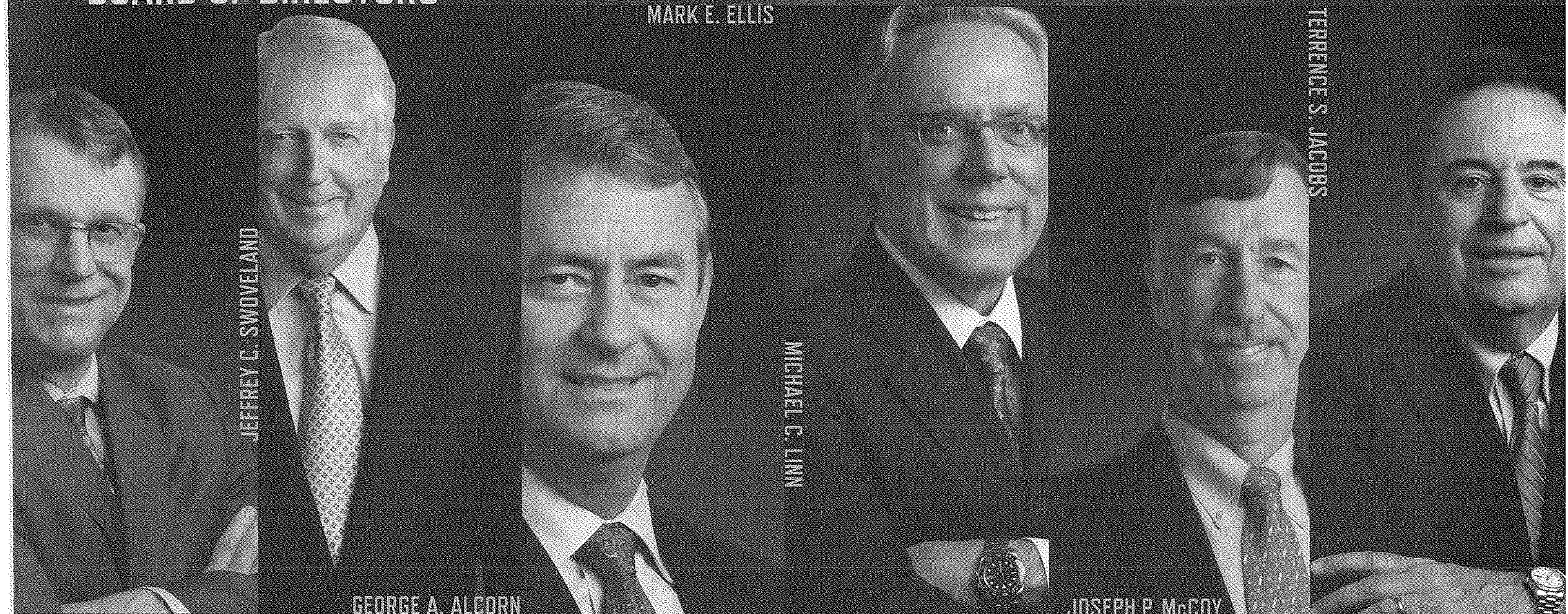
(1) (Oil and natural gas capital costs expended) divided by (Annual additions, excluding price-related revisions)

(2) (Annual additions, excluding price-related revisions) divided by (Annual production)

(3) (Oil and natural gas capital costs expended, excluding acquisitions) divided by (Annual additions, excluding price-related revisions and acquisitions)

(4) (Annual additions, excluding price-related revisions and acquisitions) divided by (Annual production)

BOARD OF DIRECTORS



EXECUTIVE OFFICERS

MICHAEL C. LINN
Executive Chairman

MARK E. ELLIS
President and Chief Executive Officer

KOLJA ROCKOV
Executive Vice President and
Chief Financial Officer

CHARLENE A. RIPLEY
Senior Vice President, General Counsel
and Corporate Secretary

DAVID B. ROTTINO
Senior Vice President
and Chief Accounting Officer

ARDEN L. WALKER, JR.
Senior Vice President
and Chief Operating Officer

INVESTOR RELATIONS

Clay P. Jeansonne
Vice President – Investor Relations
ir@linnenergy.com
281.840.4110

UNITHOLDER INFORMATION

Unitholder Inquiries

Requests for information concerning unit certificates should be made directly to the Transfer Agent and Registrar:

American Stock Transfer & Trust Company
Toll Free: 800.937.5449
Worldwide: 718.921.8200
www.amstock.com

Exchange Listing

The Nasdaq Global Select Market
The Company's CEO Certification has been submitted to the Nasdaq Global Select Market, and its Sarbanes-Oxley Act Section 302 CEO/CFO Certifications were filed in its 2009 Form 10-K.
Trading Symbol: LINE
Website: www.linnenergy.com

Form 10-K Report and Financial Statements

A copy of the Company's 2009 Form 10-K as filed with the Securities and Exchange Commission will be furnished, without charge, to any unitholder upon request.

CORPORATE HEADQUARTERS

JPMorgan Chase Tower
600 Travis, Suite 5100
Houston, Texas 77002
281.840.4000

FORWARD-LOOKING STATEMENTS

Statements made in this Annual Report that are not historical facts are forward-looking statements. These statements are based on certain assumptions and expectations made by the Company which reflect management's experience, estimates and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or anticipated in the forward-looking statements. These include risks relating to financial performance and results, our indebtedness under our credit facility, availability of sufficient cash flow to pay distributions and execute our business plan, prices and demand for gas, oil and natural gas liquids, our ability to replace reserves and efficiently develop our current reserves, our ability to make acquisitions on economically acceptable terms, and other important factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. See "Risk Factors" in the Company's 2009 Annual Report on Form 10-K and any other public filings and press releases. LINN Energy undertakes no obligation to publicly update any forward-looking statements, whether as a result of new information or future events.

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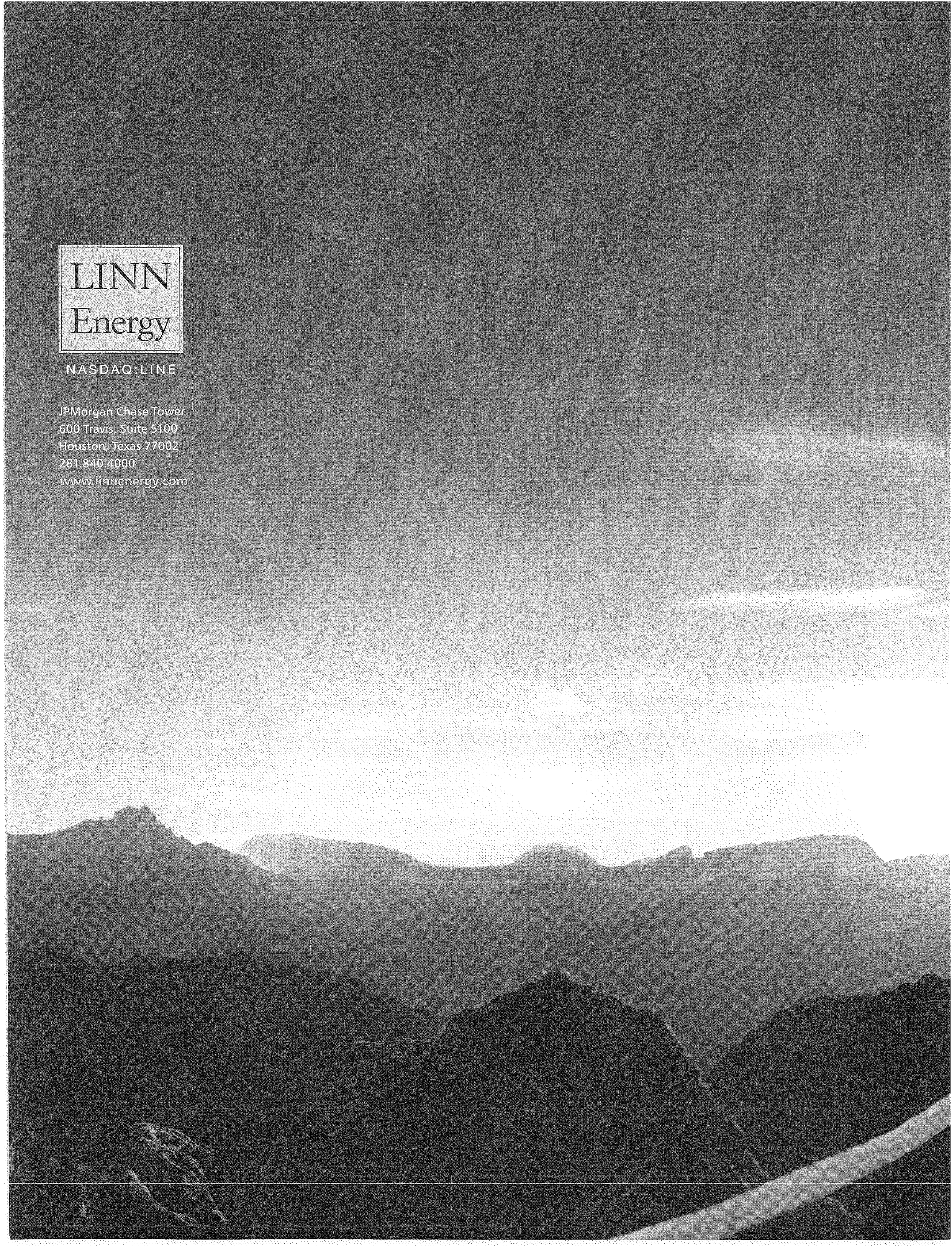

LINN Energy

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