LINN ENERGY, LLC
Form 10-K
February 23, 2012

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

Form 10-K

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

For the fiscal year ended December 31, 2011

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

Commission file number: 000-51719

LINN ENERGY, LLC
(Exact name of registrant as specified in its charter)

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

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

Title of each class	Name of each exchange on which registered
Units Representing Limited Liability Company Interests	The NASDAQ 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 x No o

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No o

Indicate by check mark 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 x No o

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

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

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

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $6.8 billion on June 30, 2011, based on $39.07 per unit, the last reported sales price of the units on The NASDAQ Global Select Market on such date.

As of January 31, 2012, there were 199,366,666 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 24, 2012.

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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:

Basin. A large area with a relatively thick accumulation of sedimentary rocks.

Bbl. One stock tank barrel or 42 United States ("U.S.") gallons liquid volume.

Bcf. One billion cubic feet.

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

Formation. A stratum of rock that is recognizable from adjacent strata consisting mainly of a certain type of rock or combination of rock types with thickness that may range from less than two feet to hundreds of feet.

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.

GLOSSARY OF TERMS - Continued

MMMBtu. One billion British thermal units.

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

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

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.

Spacing. The number of wells which conservation laws allow to be drilled on a given area of land.

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GLOSSARY OF TERMS - Continued

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.

Zone. A stratigraphic interval containing one or more reservoirs.

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Part I

Item 1. Business

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

References

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

A reference to a "Note" herein refers to the accompanying Notes to Consolidated Financial Statements contained in 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 ("U.S."), primarily in the Mid-Continent, the Permian Basin, Michigan, California and the Williston Basin.

Proved reserves at December 31, 2011, were 3,370 Bcfe, of which approximately 34% were oil, 50% were natural gas and 16% were natural gas liquids ("NGL"). Approximately 60% were classified as proved developed, with a total standardized measure of discounted future net cash flows of $6.6 billion. At December 31, 2011, the Company operated 7,759 or 69% of its 11,230 gross productive wells and had an average proved reserve-life index of approximately 22 years, based on the December 31, 2011, reserve report and fourth quarter 2011 annualized production.

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 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 it believes will be 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.

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Since January 1, 2007, excluding three acquisitions of Appalachian Basin properties sold in July 2008, the Company has completed 33 acquisitions of working and royalty interests in oil and natural gas properties and related gathering and pipeline assets. Total acquired proved reserves were approximately 2.8 Tcfe at the date of acquisition with acquisition costs of approximately $2.26 per Mcfe. The Company finances acquisitions with a combination of funds from equity and debt offerings, bank borrowings and cash flow 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 generally 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 2012, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $940 million, including $880 million related to its oil and natural gas capital program and $40 million related to its plant and pipeline capital. This estimate is under continuous review and is subject to ongoing adjustments. The Company expects to fund these capital expenditures primarily with cash flow from operations and bank borrowings.

Reduce Cash Flow Volatility Through 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 and natural gas 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 commodity hedging transactions are primarily in the form of swap contracts and put options that are designed to provide a fixed price (swap contracts) or fixed price floor with the opportunity for upside (put options) that the Company will receive as compared to floating market prices. The Company has derivative contracts in place for 2011 through 2016 at average prices ranging from a low of $95.39 per Bbl to a high of $98.44 per Bbl for oil and from a low of $5.00 per MMBtu to a high of $5.84 per MMBtu for natural gas. See Note 7 for the specific years and the related commodity prices. Additionally, the Company has derivative contracts in place covering a substantial portion of its exposure to the Mid-Continent natural gas basis differential through 2015 and its timing risk exposure on Mid-Continent and Permian Basin oil sales through 2014. For additional details about the Company's 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.

In addition, the Company may from time to time enter into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates. Currently, the Company has no outstanding interest rate swaps.

Recent Developments

Acquisitions

On December 15, 2011, the Company completed the acquisition of certain oil and natural gas properties located primarily in the Granite Wash of Texas and Oklahoma from Plains Exploration & Production Company ("Plains")

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for total consideration of approximately $544 million. The acquisition included approximately 51 MMBoe (306 Bcfe) of proved reserves as of the acquisition date.

On November 1, 2011, and November 18, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin for total consideration of approximately $110 million. The acquisitions included approximately 7 MMBoe (42 Bcfe) of proved reserves as of the acquisition dates.

On June 1, 2011, the Company completed the acquisition of certain oil and natural gas properties in the Cleveland play, located in the Texas Panhandle, from Panther Energy Company, LLC and Red Willow Mid-Continent, LLC (collectively referred to as "Panther") for total consideration of approximately $223 million. The acquisition included approximately 9 MMBoe (54 Bcfe) of proved reserves as of the acquisition date.

On May 2, 2011, and May 11, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Williston Basin for total consideration of approximately $153 million. The acquisitions included approximately 6 MMBoe (35 Bcfe) of proved reserves as of the acquisition dates.

On April 1, 2011, and April 5, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin for total consideration of approximately $239 million. The acquisitions included approximately 13 MMBoe (79 Bcfe) of proved reserves as of the acquisition dates.

On March 31, 2011, the Company completed the acquisition of certain oil and natural gas properties located in the Williston Basin from an affiliate of Concho Resources Inc. ("Concho") for total consideration of approximately $194 million. The acquisition included approximately 8 MMBoe (50 Bcfe) of proved reserves as of the acquisition date.

During 2011, the Company completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The Company, in the aggregate, paid approximately $38 million in total consideration for these properties.

Proved reserves as of the acquisition date for all of the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month.

The Company regularly engages in discussions with potential sellers regarding acquisition opportunities. Such acquisition efforts may involve its participation in auction processes, as well as situations in which the Company believes it is the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts can involve assets that, if acquired, would have a material effect on its financial condition and results of operations.

Distributions

On January 27, 2012, the Company's Board of Directors declared a cash distribution of $0.69 per unit, or $2.76 per unit on an annualized basis, with respect to the fourth quarter of 2011. The distribution, totaling approximately $138 million, was paid on February 14, 2012, to unitholders of record as of the close of business on February 7, 2012.

Operating Regions

The Company's properties are located in six operating regions in the U.S.:

- 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;

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- Permian Basin, which includes areas in West Texas and Southeast New Mexico;
- Michigan, which includes the Antrim Shale formation in the northern part of the state;
- California, which includes the Brea Olinda Field of the Los Angeles Basin; and
- Williston Basin, which includes the Bakken formation in North Dakota.

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 10,000 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, 2011, of which 49% were classified as proved developed reserves. This region produced 172 MMcfe/d or 47% of the Company's 2011 average daily production. During 2011, the Company invested approximately $268 million to drill in this region. During 2012, the Company anticipates spending approximately 65% of its total oil and natural gas capital budget for development activities in the Mid-Continent Deep region, primarily in the Deep Granite Wash formation.

To more efficiently transport its natural gas in the Mid-Continent Deep region to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 285 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the Texas Panhandle.

Mid-Continent Shallow

The Mid-Continent Shallow region includes properties producing from the Brown Dolomite formation in the Texas Panhandle, which produces at depths of approximately 3,200 feet, as well as properties in Oklahoma, Louisiana and Illinois, which produce at depths of less than 8,000 feet. Mid-Continent Shallow proved reserves represented approximately 20% of total proved reserves at December 31, 2011, of which 70% were classified as proved developed reserves. This region produced 63 MMcfe/d or 17% of the Company's 2011 average daily production. During 2011, the Company invested approximately $9 million to drill in this region. During 2012, the Company anticipates spending approximately 2% of its total oil and natural gas capital budget for development activities in the Mid-Continent Shallow region.

To more efficiently transport its natural gas in the Mid-Continent Shallow region to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 665 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the Texas Panhandle.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the U.S. The Company's properties are located in West Texas and Southeast New Mexico and produce at depths ranging from 2,000 feet to 12,000 feet. Permian Basin proved reserves represented approximately 16% of total proved reserves at December 31, 2011, of which 56% were classified as proved developed reserves. This region produced 73 MMcfe/d or 20% of the Company's 2011 average daily production. During 2011, the Company invested approximately $255 million to drill in this region. During 2012, the Company anticipates spending approximately 25% of its total oil and natural gas capital budget for development activities in the Permian Basin region, primarily in the Wolfberry trend.

Michigan

The Michigan region includes properties producing from the Antrim Shale formation in the northern part of the state, which produces at depths ranging from 600 feet to 2,200 feet. Michigan proved reserves represented approximately 9% of total proved reserves at December 31, 2011, of which 90% were classified as proved developed reserves. This region produced 35 MMcfe/d or 9% of the Company's 2011 average daily production. During 2011, the Company invested approximately $3 million to drill in this region. During 2012, the Company

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anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the Michigan region.

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 ranging from 1,000 feet to 7,500 feet. California proved reserves represented approximately 6% of total proved reserves at December 31, 2011, of which 93% were classified as proved developed reserves. This region produced 14 MMcfe/d or 4% of the Company's 2011 average daily production. During 2011, the Company invested approximately $6 million to drill in this region. During 2012, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the California region.

Williston Basin

The Williston Basin is one of the premier oil basins in the U.S. The Company's properties are located in North Dakota and produce at depths ranging from 9,000 feet to 12,000 feet. Williston Basin proved reserves represented approximately 2% of total proved reserves at December 31, 2011, of which 48% were classified as proved developed reserves. This region produced 12 MMcfe/d or 3% of the Company's 2011 average daily production. During 2011, the Company invested approximately $39 million to drill in this region. During 2012, the Company anticipates spending approximately 6% of its total oil and natural gas capital budget for development activities in the Williston Basin region.

Drilling and Acreage

The following sets forth the wells drilled in the Mid-Continent Deep, Mid-Continent Shallow, Permian Basin, Michigan, California and Williston 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 the Company's working interest):

	Year Ended December 31,		
	2011	2010	2009
Gross wells:			
Productive	292	138	72
Dry	2	1	1
	294	139	73
Net development wells:			
Productive	186	116	35
Dry	2	1	1
	188	117	36
Net exploratory wells:			
Productive	—	—	—
Dry	—	—	—
	—	—	—

The totals above do not include 8 and 25 lateral segments added to existing vertical wellbores in the Mid-Continent Shallow region during the years ended December 31, 2010, and December 31, 2009, respectively. There were no lateral segments added to existing vertical wellbores during the year ended December 31, 2011. At December 31, 2011, the Company had 85 gross (51 net) wells in process (no wells were temporarily suspended).

This 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

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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, 2011:

	Total (1)
Proved undeveloped	2,302
Other locations	4,154
Total drilling locations	6,456
Leasehold interests – net acres (in thousands)	1,116

(1) Does not include optimization projects.

As shown in the table above, as of December 31, 2011, the Company had 2,302 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 4,154 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 sets forth information relating to the productive wells in which the Company owned a working interest as of December 31, 2011. 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 2,500 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)	3,889	2,925	3,870	3,578	7,759	6,503
Nonoperated (2)	1,843	369	1,628	207	3,471	576
	5,732	3,294	5,498	3,785	11,230	7,079

(1) The Company had 12 operated wells with multiple completions at December 31, 2011.

(2) The Company had no nonoperated wells with multiple completions at December 31, 2011.

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Developed and Undeveloped Acreage

The following sets forth information relating to leasehold acreage as of December 31, 2011:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage	2,352	1,060	133	56	2,485	1,116

Production, Price and Cost History

The Company's natural gas production is primarily sold under market sensitive price contracts, which typically sell at a differential to the New York Mercantile Exchange ("NYMEX"), Panhandle Eastern Pipeline ("PEPL"), El Paso Permian Basin, or Mich Con city-gate 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, 2011, approximately 90% of the Company's natural gas and NGL production was sold under short-term contracts at market-sensitive or spot prices. At December 31, 2011, the Company had natural gas throughput delivery commitments under long-term contracts of approximately 784 MMcf for the year ended December 31, 2012, and approximately 31 Bcf to be delivered by August 2015.

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, 2011, approximately 90% of its oil production was sold under short-term contracts. At December 31, 2011, 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 and put options 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.

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

	Year Ended December 31, 2011	2010	2009
Average daily production:			
Natural gas (MMcf/d)	175	137	125
Oil (MBbls/d)	21.5	13.1	9.0
NGL (MBbls/d)	10.8	8.3	6.5
Total (MMcfe/d)	369	265	218
Weighted average prices (hedged): (1)			
Natural gas (Mcf)	$ 8.20	$ 8.52	$ 8.27
Oil (Bbl)	$ 89.21	$ 94.71	$ 110.94
NGL (Bbl)	$ 42.88	$ 39.14	$ 28.04
Weighted average prices (unhedged): (2)			
Natural gas (Mcf)	$ 4.35	$ 4.24	$ 3.51
Oil (Bbl)	$ 91.24	$ 75.16	$ 55.25
NGL (Bbl)	$ 42.88	$ 39.14	$ 28.04
Average NYMEX prices:			
Natural gas (MMBtu)	$ 4.05	$ 4.40	$ 3.99
Oil (Bbl)	$ 95.12	$ 79.53	$ 61.94
Costs per Mcfe of production:			
Lease operating expenses	$ 1.73	$ 1.64	$ 1.67
Transportation expenses	$ 0.21	$ 0.20	$ 0.23
General and administrative expenses (3)	$ 0.99	$ 1.02	$ 1.08
Depreciation, depletion and amortization	$ 2.48	$ 2.46	$ 2.53
Taxes, other than income taxes	$ 0.58	$ 0.47	$ 0.35

(1) Includes the effect of realized gains on derivatives of approximately $230 million (excluding $27 million realized gains on canceled contracts), $308 million and $401 million (excluding $49 million realized net gains on canceled contracts) for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, respectively.

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

(3) General and administrative expenses for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, include approximately $21 million, $13 million and $15 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, were $0.83 per Mcfe, $0.88 per Mcfe and $0.90 per Mcfe, respectively. This measure is not in accordance with U.S. Generally Accepted Accounting Principles ("GAAP") and thus is a non-GAAP measure, used by management to analyze the Company's performance.

Reserve Data

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, 2011, based on reserve reports prepared by independent engineers, DeGolyer and MacNaughton:

Estimated proved developed reserves:			
Natural gas (Bcf)		998	
Oil (MMBbls)		125	
NGL (MMBbls)		48	
Total (Bcfe)		2,034	
Estimated proved undeveloped reserves:			
Natural gas (Bcf)		677	
Oil (MMBbls)		64	
NGL (MMBbls)		46	
Total (Bcfe)		1,336	
Estimated total proved reserves (Bcfe)		3,370	
Proved developed reserves as a percentage of total proved reserves		60	%
Standardized measure of discounted future net cash flows (in millions) (1)	$	6,615	
Representative NYMEX prices: (2)			
Natural gas (MMBtu)	$	4.12	
Oil (Bbl)	$	95.84	

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

(2) 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. The average price used to estimate reserves is held constant over the life of the reserves.

During the year ended December 31, 2011, the Company's proved undeveloped reserves ("PUDs") increased to 1,336 Bcfe from 935 Bcfe at December 31, 2010, representing an increase of 401 Bcfe. The increase was primarily due to 364 Bcfe added as a result of the Company's acquisitions in the Mid-Continent Deep, Permian Basin and Williston Basin regions and 346 Bcfe added as a result of its drilling activities in the Texas Panhandle Granite Wash, partially offset by PUDs developed during 2011.

During the year ended December 31, 2011, the Company incurred approximately $307 million in capital expenditures to convert 178 Bcfe of reserves classified as PUDs at December 31, 2010. Based on the December 31, 2011 reserve report, the amounts of capital expenditures estimated to be incurred in 2012, 2013 and 2014 to develop the Company's PUDs are approximately $765 million, $836 million and $556 million, respectively. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs and product prices. Of the 1,336 Bcfe of PUDs at December 31, 2011, seven Bcfe remained undeveloped for five years or more; however, the property is included in the Company's 2012 development plan. All PUD properties are included in the Company's current five-year development plan.

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, is 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 the 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 Executive 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.” The Company has not filed reserve estimates with any federal authority or agency, with the exception of the SEC.

Operational Overview

General

The Company generally 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. 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, 2011, sales of oil, natural gas and NGL to Enbridge Energy Partners, L.P. and DCP Midstream Partners, LP accounted for approximately 21% and 19%, respectively, of the Company’s total production volumes, or 40% 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 U.S. 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 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.

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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, areas inhabited by endangered species 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 production rate of oil, natural gas and NGL 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 U.S. 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 U.S.;
- Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), 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 ("RCRA"), which governs the management of solid waste;
- Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

Various states regulate the drilling for, and the production, gathering and sale of, oil, 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 regulations, 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, hydraulic fracturing and air emissions.

Climate Change

In response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to warming of the Earth's atmosphere, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that would require a reduction in emissions of greenhouse gases ("GHG") from motor vehicles and also may trigger construction and operating permit review for GHG emissions from certain stationary sources. The EPA has asserted that the final motor vehicle GHG emission standards triggered construction and operating permit requirements for stationary sources. Thus, on June 3, 2010, the EPA issued a final rule to address permitting of GHG emissions from stationary sources under the Clean Air Act's Prevention of Significant Deterioration ("PSD") and Title V programs. This final rule "tailors" the PSD and Title V programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. In addition, on November 8, 2010, the EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to the EPA's existing GHG reporting rule published in 2009. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO2 equivalent per year will now be required to report annual GHG emissions to the EPA, with the first report due on September 28, 2012. In addition, both houses of Congress have considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Any laws or regulations that may be adopted to restrict or reduce emissions of U.S. greenhouse gases could require the Company to incur increased operating costs, and could have an adverse effect on demand for oil and natural gas.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs. However, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. Moreover, on November 23, 2011, the EPA announced that it was granting, in part, a petition to initiate rulemaking under the Toxic Substances Control Act ("TSCA"), relating to chemical substances and mixtures used in oil and gas exploration or production. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites and also increased costs to make wells productive.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic-fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by

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2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. These on-going or proposed studies, depending on their course and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms. Moreover, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, both Texas and Louisiana have adopted disclosure regulations requiring varying degrees of disclosure of the constituents in hydraulic fracturing fluids. Any such added regulation in states where the Company operates could lead to operational delays, increased operating costs and additional regulatory burdens, and reduced production of oil and natural gas, which could adversely affect the Company’s revenues and results of operations.

Endangered Species Act

The federal Endangered Species Act (“ESA”) restricts activities that may affect endangered and threatened species or their habitats. Some of the Company’s operations may be located in areas that are designated as habitat for endangered or threatened species. The Company believes that it is currently in substantial compliance with the ESA. However, the designation of previously unprotected species as being endangered or threatened could cause the Company to incur additional costs or become subject to operating restrictions in areas where the species are known to exist.

Air Emissions

On July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (“NSPS”) and National Emissions Standards for Hazardous Air Pollutants (“NESHAP”) programs. The EPA’s proposed rules also include NSPS standards for completions of hydraulically fractured gas wells, applicable to newly drilled and fractured wells and also existing wells that are refractured. These standards include the reduced emission completion (“REC”) techniques developed in EPA’s Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. Further, the proposed regulations under NESHAP include maximum achievable control technology (“MACT”) standards for certain equipment not currently subject to such standards. The Company is currently evaluating the effect these proposed rules could have on its business. Final action on the proposed rules is expected no later than April 3, 2012. If these or other initiatives result in an increase in regulation, it could increase the Company’s costs or reduce its production, which could have a material adverse effect on its results of operations and cash flows.

The Company cannot predict how future environmental laws and regulations may impact its properties or operations. For the year ended December 31, 2011, 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 2012 or that will otherwise have a material impact on its financial position or results of operations.

Employees

As of December 31, 2011, the Company employed approximately 824 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 Houston, Texas. The principal executive offices are located at 600 Travis, Suite 5100, Houston, Texas 77002. The main telephone number is (281) 840-4000.

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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 discussions about the Company's:

- business strategy;
- acquisition strategy;
- financial strategy;
- ability to maintain or grow distributions;
- 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," "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.

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Item 1A. Risk Factors

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

We may not have sufficient cash flow from operations to pay the quarterly distribution at the current distribution level, 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 or at all. 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 on acceptable terms 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 and the Indentures governing our 2019 Senior Notes, 2010 Issued Senior Notes, and our Original Senior Notes, as defined in Note 6;
- prevailing economic conditions;
- access to credit or capital markets; 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 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;
- disputes arising out of acquisitions;
- 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 2019 Senior Notes, 2010 Issued Senior Notes, and Original Senior Notes (collectively, "Senior Notes") and from time to time, our Credit Facility. For a discussion of our Senior Notes, see Note 6. The Indentures governing our Senior Notes have 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.

As of January 31, 2012, we had an aggregate of approximately $3.3 billion outstanding under Senior Notes and our Credit Facility (with additional borrowing capacity of approximately $1.3 billion under our Credit Facility). 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 are also required to comply with certain financial covenants and ratios under our Credit Facility and the Indentures governing our Senior Notes. 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, in part, 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 primarily 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 a 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. Furthermore, to the extent 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.

The borrowing base 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 therefore 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 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 and borrow on favorable terms will be affected 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.

Disruptions in the capital and credit markets could limit our ability to access these markets or significantly increase our cost to borrow. 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 access the capital and credit markets on favorable terms, our ability to make acquisitions and 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 and natural gas, 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 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.

Counterparty failure 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 U.S. 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 manner. 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 amounts 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.

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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 and production 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 to the extent necessary, with equity and debt offerings or bank borrowings. 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 flow from operations or cash 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, results of operations and our ability to pay distributions. 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, 2011, we had 2,302 proved undeveloped drilling locations. To the extent that we do not drill these locations 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, 2011, Enbridge Energy Partners, L.P. and DCP Midstream Partners, LP accounted for approximately 21% and 19%, respectively, of our total production volumes, or 40% in the aggregate. For the year ended December 31, 2010, DCP Midstream Partners, LP, Enbridge Energy Partners, L.P. and ConocoPhillips accounted for approximately 19%, 17% and 12%, respectively, of our total volumes, or 48% 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 U.S. 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, 2011, we had identified 6,456 drilling locations, of which 2,302 were proved undeveloped locations and 4,154 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 4,154 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.

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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 or at all. 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. 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. 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. 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. In addition, 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."

Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. For example, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, both Texas and Louisiana have adopted disclosure regulations requiring varying degrees of disclosure of the constituents in hydraulic fracturing fluids. Such efforts could have an adverse effect on our oil and natural gas production activities. For a more detailed discussion of hydraulic fracturing matters impacting our business, 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;

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- 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 units 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

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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.

The value of an investment in our units could be affected by recent and potential federal tax increases.

Absent new legislation extending the current rates, in taxable years beginning after December 31, 2012, the highest marginal U.S. federal income tax rate applicable to ordinary income and long-term capital gains of individuals will increase to 39.6% and 20%, respectively. Moreover, these rates are subject to change by new legislation at any time.

The Health Care and Education Reconciliation Act of 2010 includes a provision that, in taxable years beginning after December 31, 2012, subjects certain individuals, estates and trusts to an Unearned Income Medicare Contribution tax of 3.8% on certain income. In the case of an individual having a modified adjusted gross income in excess of $200,000 (or $250,000 for married taxpayers filing joint returns), the provision imposes a tax equal to 3.8% of the lesser of such excess and the individual's "net investment income," which will include net income and gains from the ownership or disposition of our units.

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.

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.

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Item 1A. Risk Factors - Continued

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 U.S. federal tax returns and pay tax on their share of our taxable income.

We treat each purchaser of units as having the same economic and tax characteristics 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 and other positions that are intended to maintain such uniformity. These positions may not conform with all aspects of existing Treasury regulations and may affect the amount or timing of income, gain, loss or deduction allocable to a unitholder or the amount of gain from a unitholder's sale of units. A successful IRS challenge to those positions could also adversely affect the amount or timing of income, gain, loss or deduction allocable to a unitholder, or the amount of gain from a unitholder's 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 12-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 12-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

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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 2011, we have been registered to do business or have owned assets in Pennsylvania, California, Oklahoma, Kansas, New Mexico, Illinois, Indiana, Arkansas, Colorado, Louisiana, Michigan, 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 U.S. federal, state and local tax returns that may be required of such unitholder.

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 U.S. 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.

Derivatives legislation enacted in 2010 could have an adverse impact on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

New comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodity Futures Trading Commission (the "CFTC") to regulate certain markets for over-the-counter ("OTC") derivative products. Currently, rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the new legislation to cause significant portions of derivatives to clear through clearinghouses. The significance of the effect on our business will depend in part on whether we are determined to be a major swap participant or swap dealer or a qualifying end-user, as those terms are defined in the final rules. Depending on those determinations, we may be required to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivatives activities. The CFTC has proposed regulations that, if adopted, may provide to us the certainty that we will not be required to comply with margin requirements or clearing requirements, but the timing of any adoption of any such regulations, and their

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scope, are uncertain. Even if we are not deemed a major swap participant or swap dealer, the rules could impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations, including determinations with respect to the applicability of margin requirements and other trading structures, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at the current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

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 a substantial majority of 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, Michigan, New Mexico, Oklahoma and Texas.

Item 3. Legal Proceedings

For a discussion of general legal proceedings, see Note 11 of Notes to Consolidated Financial Statements.

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Executive Officers of the Company

Name	Age	Position with the Company
Mark E. Ellis	56	Chairman, President and Chief Executive Officer
Kolja Rockov	41	Executive Vice President and Chief Financial Officer
Arden L. Walker, Jr.	52	Executive Vice President and Chief Operating Officer
Charlene A. Ripley	48	Senior Vice President and General Counsel
David B. Rottino	46	Senior Vice President of Finance, Business Development and Chief Accounting Officer

Mark E. Ellis is the Chairman, President and Chief Executive Officer and has served in such capacity since December 2011. He previously served as President, Chief Executive Officer and Director from January 2010 to December 2011. 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 serves on the boards of America's Natural Gas Alliance, 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 and has served in such capacity since March 2005. Mr. Rockov serves on the Board of Small Steps Nurturing Center in Houston.

Arden L. Walker, Jr. is the Executive Vice President and Chief Operating Officer and has served in such capacity since January 2011. From January 2010 to January 2011, he served as Senior Vice President and Chief Operating Officer. Mr. Walker joined the Company in February 2007 as Senior Vice President, Operations and Chief Engineer, to oversee its Texas, Oklahoma and California operations. He now oversees the Company's operations in all regions. Mr. Walker is a member of the Society of Petroleum Engineers and Independent Petroleum Association of America. He currently serves on the boards of the Sam Houston Area Council of the Boy Scouts of America and Theatre Under The Stars.

Charlene A. Ripley is the Senior Vice President and General Counsel and has served in such capacity since September 2011. She served as Senior Vice President, General Counsel and Corporate Secretary from April 2007 to September 2011. Ms. Ripley currently serves on the board of the Texas General Counsel Forum and on the advisory board of the Women's Energy Network. She also serves on several nonprofit boards, including the Impact Youth Development Center, Girls Inc. and the American Heart Association of Houston. She is a member of the United Way of Greater Houston Women's Initiative.

David B. Rottino is the Senior Vice President of Finance, Business Development and Chief Accounting Officer and has served in such capacity since July 2010. From June 2008 to July 2010, Mr. Rottino served as the Senior Vice President and Chief Accounting Officer. Prior to joining Linn Energy, Mr. Rottino served as Vice President and E&P Controller for El Paso Corporation from June 2006 to May 2008. 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 Camp for All.

Item 4. Mine Safety Disclosures

Not applicable

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Part II

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

Market Information

The Company's units are listed on The NASDAQ Global Select Market ("NASDAQ") under the symbol "LINE" and began trading on January 13, 2006, after pricing of its IPO. At the close of business on January 31, 2012, there were approximately 192 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 High	Unit Price Range Low	Cash Distributions Declared Per Unit
2011:			
October 1 – December 31	$ 39.05	$ 32.80	$ 0.69
July 1 – September 30	$ 40.90	$ 31.91	$ 0.69
April 1 – June 30	$ 40.38	$ 36.65	$ 0.66
January 1 – March 31	$ 39.94	$ 37.34	$ 0.66
2010:			
October 1 – December 31	$ 37.49	$ 31.94	$ 0.66
July 1 – September 30	$ 31.96	$ 26.15	$ 0.63
April 1 – June 30	$ 27.18	$ 22.69	$ 0.63
January 1 – March 31	$ 28.80	$ 24.80	$ 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.

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

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

invested in the Company on December 31, 2006, and 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.

	December 31, 2006	December 31, 2007	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
LINN Energy	$ 100	$ 84	$ 57	$ 121	$ 177	$ 193
Alerian MLP Index	$ 100	$ 113	$ 71	$ 126	$ 171	$ 195
S&P 500 Index	$ 100	$ 105	$ 66	$ 84	$ 97	$ 99

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.

Sales of Unregistered Securities

None.

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

Issuer Purchases of Equity Securities

The following sets forth information with respect to the Company’s repurchases of its units during the fourth quarter of 2011:

Period	Total Number of Units Purchased	Average Price Paid Per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Units that May Yet be Purchased Under the Plans or Programs (1) (in millions)
October 1 – 31	129,734	$ 32.08	129,734	$ 56

(1) In October 2008, the Board of Directors of the Company authorized the repurchase of up to $100 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.

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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 Well Service, Inc. operations, which were disposed of in 2008, are classified as discontinued operations for years ended December 31, 2007, through December 31, 2009 (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,				
	2011	2010	2009	2008	2007
	(in thousands, except per unit amounts)				
Statement of operations data:					
Oil, natural gas and natural gas liquids sales	$ 1,162,037	$ 690,054	$ 408,219	$ 755,644	$ 255,927
Gains (losses) on oil and natural gas derivatives	449,940	75,211	(141,374)	662,782	(345,537)
Depreciation, depletion and amortization	334,084	238,532	201,782	194,093	69,081
Interest expense, net of amounts capitalized	259,725	193,510	92,701	94,517	38,974
Income (loss) from continuing operations	438,439	(114,288)	(295,841)	825,657	(356,194)
Income (loss) from discontinued operations, net of taxes (1)			(2,351)	173,959	(8,155)
Net income (loss)	438,439	(114,288)	(298,192)	999,616	(364,349)
Income (loss) per unit – continuing operations:					
Basic	2.52	(0.80)	(2.48)	7.18	(5.17)
Diluted	2.51	(0.80)	(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	2.52	(0.80)	(2.50)	8.70	(5.29)
Diluted	2.51	(0.80)	(2.50)	8.70	(5.29)
Distributions declared per unit	2.70	2.55	2.52	2.52	2.18
Weighted average units outstanding	172,004	142,535	119,307	114,140	68,916
Cash flow data:					
Net cash provided by (used in):					
Operating activities (2)	$ 518,706	$ 270,918	$ 426,804	$ 179,515	$ (44,814)

Investing activities	(2,130,360)	(1,581,408)	(282,273)	(35,550)	(2,892,420)
Financing activities	1,376,767	1,524,260	(150,968)	(116,738)	2,932,080
Balance sheet data:					
Total assets	$ 8,000,137	$ 5,933,148	$ 4,340,256	$ 4,722,020	$ 3,807,703
Long-term debt	3,993,657	2,742,902	1,588,831	1,653,568	1,443,830
Unitholders' capital	3,428,910	2,788,216	2,452,004	2,760,686	2,026,641

(1) Includes gains (losses) on sale of assets, net of taxes.

(2) Includes premiums paid for derivatives of approximately $134 million, $120 million, $94 million, $130 million and $279 million for the years ended December 31, 2011, December 31, 2010, December 31, 2009, December 31, 2008, and December 31, 2007, respectively.

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Item 6. Selected Financial Data - Continued

	At or for the Year Ended December 31,				
	2011	2010	2009	2008	2007
Production data:					
Average daily production – continuing operations:					
Natural gas (MMcf/d)	175	137	125	124	51
Oil (MBbls/d)	21.5	13.1	9.0	8.6	3.4
NGL (MBbls/d)	10.8	8.3	6.5	6.2	2.7
Total (MMcfe/d)	369	265	218	212	87
Average daily production – discontinued operations:					
Total (MMcfe/d)				12	24
Estimated proved reserves – continuing operations: (1)					
Natural gas (Bcf)	1,675	1,233	774	851	833
Oil (MMBbls)	189	156	102	84	55
NGL (MMBbls)	94	71	54	51	43
Total (Bcfe)	3,370	2,597	1,712	1,660	1,419
Estimated proved reserves – discontinued operations: (1)					
Total (Bcfe)					197

(1) In accordance with SEC regulations, reserves at December 31, 2011, December 31, 2010, and 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. The price used to estimate reserves is held constant over the life of the reserves.

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

The following discussion and analysis should be read in conjunction with the "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 six operating regions in the United States ("U.S."):

- 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;
- Permian Basin, which includes areas in West Texas and Southeast New Mexico;
- Michigan, which includes the Antrim Shale formation in the northern part of the state;
- California, which includes the Brea Olinda Field of the Los Angeles Basin; and
- Williston Basin, which includes the Bakken formation in North Dakota.

Results for the year ended December 31, 2011, included the following:

- oil, natural gas and NGL sales of approximately $1.2 billion compared to $690 million in 2010;
- average daily production of 369 MMcfe/d compared to 265 MMcfe/d in 2010;
- realized gains on commodity derivatives of approximately $257 million compared to $308 million in 2010;
- adjusted EBITDA of approximately $998 million compared to $732 million in 2010;
- adjusted net income of approximately $313 million compared to $219 million in 2010;
- capital expenditures, excluding acquisitions, of approximately $697 million compared to $263 million in 2010; and
- 294 wells drilled (292 successful) compared to 139 wells drilled (138 successful) in 2010.

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 income (loss) from continuing operations 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 unrealized (gains) losses on derivatives, realized (gains) losses on canceled derivatives, impairment of long-lived assets, loss on extinguishment of debt and (gains) losses on sale of assets, net. See “Non-GAAP Financial Measures” on page 58 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 December 15, 2011, the Company completed the acquisition of certain oil and natural gas properties located primarily in the Granite Wash of Texas and Oklahoma from Plains Exploration & Production Company ("Plains") for total consideration of approximately $544 million. The acquisition included approximately 51 MMBoe (306 Bcfe) of proved reserves as of the acquisition date.

On November 1, 2011, and November 18, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin for total consideration of approximately $110 million. The acquisitions included approximately 7 MMBoe (42 Bcfe) of proved reserves as of the acquisition dates.

On June 1, 2011, the Company completed the acquisition of certain oil and natural gas properties in the Cleveland play, located in the Texas Panhandle, from Panther Energy Company, LLC and Red Willow Mid-Continent, LLC (collectively referred to as "Panther") for total consideration of approximately $223 million. The acquisition included approximately 9 MMBoe (54 Bcfe) of proved reserves as of the acquisition date.

On May 2, 2011, and May 11, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Williston Basin for total consideration of approximately $153 million. The acquisitions included approximately 6 MMBoe (35 Bcfe) of proved reserves as of the acquisition dates.

On April 1, 2011, and April 5, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin for total consideration of approximately $239 million. The acquisitions included approximately 13 MMBoe (79 Bcfe) of proved reserves as of the acquisition dates.

On March 31, 2011, the Company completed the acquisition of certain oil and natural gas properties located in the Williston Basin from an affiliate of Concho Resources Inc. ("Concho") for total consideration of approximately $194 million. The acquisition included approximately 8 MMBoe (50 Bcfe) of proved reserves as of the acquisition date.

During 2011, the Company completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The Company, in the aggregate, paid approximately $38 million in total consideration for these properties.

Proved reserves as of the acquisition date for all of the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month.

Financing and Liquidity

The Company's Credit Facility has a borrowing base of $3.0 billion with a maximum commitment amount of $1.5 billion. The maturity date is April 2016. At January 31, 2012, the borrowing capacity under the Credit Facility was approximately $1.3 billion, which includes a $4 million reduction in availability for outstanding letters of credit.

On February 28, 2011, the Company commenced cash tender offers and related consent solicitations to purchase any and all of its outstanding 2017 Senior Notes and 2018 Senior Notes.

In March 2011, in accordance with the provisions of the indentures related to the 2017 Senior Notes and the 2018 Senior Notes, the Company redeemed 35%, or $87 million and $90 million, respectively, of each of the original aggregate principal amount of its Original Senior Notes, as defined in Note 6.

In March 2011, in connection with its cash tender offers and related consent solicitations, the Company also accepted and purchased: 1) $105 million of the aggregate principal amount of its outstanding 2017 Senior Notes (or

65% of the remaining outstanding principal amount of its 2017 Senior Notes), and 2) $126 million aggregate principal amount of its outstanding 2018 Senior Notes (or 76% of the remaining outstanding principal amount of its 2018 Senior Notes).

In March 2011, the Company completed a public offering of units for net proceeds of approximately $623 million. The Company used a portion of the net proceeds from the sale of these units to fund the March 2011 redemptions of a portion of its outstanding 2017 Senior Notes and 2018 Senior Notes and to fund the cash tender offers and related expenses for a portion of its remaining 2017 Senior Notes and 2018 Senior Notes (see Note 6). The Company used the remaining net proceeds from the sale of units to finance a portion of the March 31, 2011, acquisition in the Williston Basin.

In May 2011, the Company issued $750 million in aggregate principal amount of 6.50% senior notes due 2019 (see Note 6) and used net proceeds of approximately $729 million to repay all of the outstanding indebtedness under its Credit Facility, fund or partially fund acquisitions and for general corporate purposes.

In June 2011, the Company repurchased an additional portion of its remaining outstanding 2017 Senior Notes and 2018 Senior Notes for approximately $17 million (or 29% of the remaining outstanding principal amount of its 2017 Senior Notes) and approximately $24 million (or 61% of the remaining outstanding principal amount of its 2018 Senior Notes), respectively. In December 2011, the Company also repurchased an additional portion of its remaining outstanding 2018 Senior Notes for approximately $2 million (or 9% of the remaining outstanding principal amount of its 2018 Senior Notes).

On August 23, 2011, the Company entered into an equity distribution agreement, pursuant to which it may from time to time issue and sell units representing limited liability company interests having an aggregate offering price of up to $500 million. In September 2011, the Company issued and sold 16,060 units representing limited liability company interests at an average unit price of $38.25 for proceeds of approximately $602,000 (net of approximately $12,000 in commissions). In December 2011, the Company issued and sold 772,104 units representing limited liability company interests at an average unit price of $38.03 for proceeds of approximately $29 million (net of approximately $587,000 in commissions). The Company used the net proceeds for general corporate purposes including the repayment of a portion of the indebtedness outstanding under its Credit Facility. At December 31, 2011, units equaling approximately $470 million in aggregate offering price remained available to be issued and sold under the agreement.

In January 2012, the Company, under its equity distribution agreement, issued and sold 1,539,651 units representing limited liability company interests at an average unit price of $38.02 for proceeds of approximately $57 million (net of approximately $1 million in commissions). The Company used the net proceeds for general corporate purposes including the repayment of a portion of the indebtedness outstanding under its Credit Facility. At January 31, 2012, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

In January 2012, the Company also completed a public offering of units for net proceeds of approximately $674 million. The Company used the net proceeds from the sale of these units to repay a portion of the outstanding indebtedness under its Credit Facility.

Commodity Derivatives

During the year ended December 31, 2011, the Company entered into commodity derivative contracts consisting of oil and natural gas swaps for certain years through 2016 and oil trade month roll swaps for October 2011 through December 2015. In September 2011, the Company canceled its oil and natural gas swaps for the year 2016 and used the realized gains of approximately $27 million to increase prices on its existing oil and natural gas swaps for the year 2012. In September 2011, the Company also paid premiums of approximately $33 million to increase prices on its existing oil puts for the years 2012 and 2013. In addition, during the fourth quarter of 2011, the Company paid premiums of approximately $52 million for put options and approximately $22 million to increase prices on its existing oil puts for 2012 and 2013.

Operating Regions

Following is a discussion of the Company's six operating regions.

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 10,000 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, 2011, of which 49% were classified as proved developed reserves. This region produced 172 MMcfe/d or 47% of the Company's 2011 average daily production. During 2011, the Company invested approximately $268 million to drill in this region. During 2012, the Company anticipates spending approximately 65% of its total oil and natural gas capital budget for development activities in the Mid-Continent Deep region, primarily in the Deep Granite Wash formation.

To more efficiently transport its natural gas in the Mid-Continent Deep region to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 285 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the Texas Panhandle.

Mid-Continent Shallow

The Mid-Continent Shallow region includes properties producing from the Brown Dolomite formation in the Texas Panhandle, which produces at depths of approximately 3,200 feet, as well as properties in Oklahoma, Louisiana and Illinois, which produce at depths of less than 8,000 feet. Mid-Continent Shallow proved reserves represented approximately 20% of total proved reserves at December 31, 2011, of which 70% were classified as proved developed reserves. This region produced 63 MMcfe/d or 17% of the Company's 2011 average daily production. During 2011, the Company invested approximately $9 million to drill in this region. During 2012, the Company anticipates spending approximately 2% of its total oil and natural gas capital budget for development activities in the Mid-Continent Shallow region.

To more efficiently transport its natural gas in the Mid-Continent Shallow region to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 665 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the Texas Panhandle.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the U.S. The Company's properties are located in West Texas and Southeast New Mexico and produce at depths ranging from 2,000 feet to 12,000 feet. Permian Basin proved reserves represented approximately 16% of total proved reserves at December 31, 2011, of which 56% were classified as proved developed reserves. This region produced 73 MMcfe/d or 20% of the Company's 2011 average daily production. During 2011, the Company invested approximately $255 million to drill in this region. During 2012, the Company anticipates spending approximately 25% of its total oil and natural gas capital budget for development activities in the Permian Basin region, primarily in the Wolfberry trend.

Michigan

The Michigan region includes properties producing from the Antrim Shale formation in the northern part of the state, which produces at depths ranging from 600 feet to 2,200 feet. Michigan proved reserves represented approximately 9% of total proved reserves at December 31, 2011, of which 90% were classified as proved developed reserves. This region produced 35 MMcfe/d or 9% of the Company's 2011 average daily production. During 2011, the Company invested approximately $3 million to drill in this region. During 2012, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the Michigan region.

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 ranging from 1,000 feet to 7,500 feet. California proved reserves represented approximately 6% of total proved reserves at December 31, 2011, of which 93% were classified as proved developed reserves. This region produced 14 MMcfe/d or 4% of the Company's 2011 average daily production. During 2011, the Company invested approximately $6 million to drill in this region. During 2012, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the California region.

Williston Basin

The Williston Basin is one of the premier oil basins in the U.S. The Company's properties are located in North Dakota and produce at depths ranging from 9,000 feet to 12,000 feet. Williston Basin proved reserves represented approximately 2% of total proved reserves at December 31, 2011, of which 48% were classified as proved developed reserves. This region produced 12 MMcfe/d or 3% of the Company's 2011 average daily production. During 2011, the Company invested approximately $39 million to drill in this region. During 2012, the Company anticipates spending approximately 6% of its total oil and natural gas capital budget for development activities in the Williston Basin region.

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

Results of Operations

Year Ended December 31, 2011, Compared to Year Ended December 31, 2010

	Year Ended December 31, 2011	2010	Variance
		(in thousands)	
Revenues and other:			
Natural gas sales	$ 278,714	$ 211,596	$ 67,118
Oil sales	714,385	359,996	354,389
NGL sales	168,938	118,462	50,476
Total oil, natural gas and NGL sales	1,162,037	690,054	471,983
Gains on oil and natural gas derivatives (1)	449,940	75,211	374,729
Marketing revenues	5,868	3,966	1,902
Other revenues	4,609	3,049	1,560
	$ 1,622,454	$ 772,280	$ 850,174
Expenses:			
Lease operating expenses	$ 232,619	$ 158,382	$ 74,237
Transportation expenses	28,358	19,594	8,764
Marketing expenses	3,681	2,716	965
General and administrative expenses (2)	133,272	99,078	34,194
Exploration costs	2,390	5,168	(2,778)
Bad debt expenses	(22)	(46)	24
Depreciation, depletion and amortization	334,084	238,532	95,552
Impairment of long-lived assets	—	38,600	(38,600)
Taxes, other than income taxes	78,522	45,182	33,340
Losses on sale of assets and other, net	3,516	6,536	(3,020)
	$ 816,420	$ 613,742	$ 202,678
Other income and (expenses)	$ (362,129)	$ (268,585)	$ (93,544)
Income (loss) before income taxes	$ 443,905	$ (110,047)	$ 553,952
Adjusted EBITDA (3)	$ 997,621	$ 732,131	$ 265,490
Adjusted net income (3)	$ 313,331	$ 219,489	$ 93,842

(1) During the year ended December 31, 2011, the Company canceled (before the contract settlement date) derivative contracts on estimated future oil and natural gas production resulting in realized gains of approximately $27 million.

(2) General and administrative expenses for the years ended December 31, 2011, and December 31, 2010, include approximately $21 million and $13 million, respectively, of noncash unit-based compensation expenses.

(3) This is a non-GAAP measure used by management to analyze the Company’s performance. See “Non-GAAP Financial Measures” on page 58 for a reconciliation of the non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

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	Year Ended December 31, 2011	2010	Variance
Average daily production:			
Natural gas (MMcf/d)	175	137	28 %
Oil (MBbls/d)	21.5	13.1	64 %
NGL (MBbls/d)	10.8	8.3	30 %
Total (MMcfe/d)	369	265	39 %
Weighted average prices (hedged): (1)			
Natural gas (Mcf)	$ 8.20	$ 8.52	(4)%
Oil (Bbl)	$ 89.21	$ 94.71	(6)%
NGL (Bbl)	$ 42.88	$ 39.14	10 %
Weighted average prices (unhedged): (2)			
Natural gas (Mcf)	$ 4.35	$ 4.24	3 %
Oil (Bbl)	$ 91.24	$ 75.16	21 %
NGL (Bbl)	$ 42.88	$ 39.14	10 %
Average NYMEX prices:			
Natural gas (MMBtu)	$ 4.05	$ 4.40	(8)%
Oil (Bbl)	$ 95.12	$ 79.53	20 %
Costs per Mcfe of production:			
Lease operating expenses	$ 1.73	$ 1.64	5 %
Transportation expenses	$ 0.21	$ 0.20	5 %
General and administrative expenses (3)	$ 0.99	$ 1.02	(3)%
Depreciation, depletion and amortization	$ 2.48	$ 2.46	1 %
Taxes, other than income taxes	$ 0.58	$ 0.47	23 %

(1) Includes the effect of realized gains on derivatives of approximately $230 million (excluding $27 million realized gains on canceled contracts) and $308 million for the years ended December 31, 2011, and December 31, 2010, respectively.

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

(3) General and administrative expenses for the years ended December 31, 2011, and December 31, 2010, include approximately $21 million and $13 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2011, and December 31, 2010, were $0.83 per Mcfe and $0.88 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company’s performance.

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Revenues and Other

Oil, Natural Gas and NGL Sales
Oil, natural gas and NGL sales increased by approximately $472 million or 68% to approximately $1.2 billion for the year ended December 31, 2011, from approximately $690 million for the year ended December 31, 2010, due to higher commodity prices and higher production volumes. Higher oil, NGL and natural gas prices resulted in an increase in revenues of approximately $126 million, $15 million and $7 million, respectively.

Average daily production volumes increased to 369 MMcfe/d during the year ended December 31, 2011, from 265 MMcfe/d during the year ended December 31, 2010. Higher oil, natural gas and NGL production volumes resulted in an increase in revenues of approximately $228 million, $60 million and $36 million, respectively.

The following sets forth average daily production by region:

	Year Ended December 31,			
	2011	2010	Variance	
Average daily production (MMcfe/d):				
Mid-Continent Deep	172	133	39	30 %
Mid-Continent Shallow	63	66	(3)	(5)%
Permian Basin	73	31	42	134 %
Michigan	35	21	14	67 %
California	14	14	—	—
Williston Basin	12	—	12	—
	369	265	104	39 %

The 30% increase in average daily production volumes in the Mid-Continent Deep region is primarily due to the Company’s 2010 and 2011 capital drilling programs in the Deep Granite Wash formation, as well as the impact of the acquisition in the Cleveland Play in June 2011. The 5% decrease in average daily production volumes in the Mid-Continent Shallow region reflects downtime related to weather and third-party plant maintenance, and the effects of natural declines, partially offset by the results of the Company’s drilling and optimization programs. The 134% increase in average daily production volumes in the Permian Basin region reflects the impact of acquisitions in 2010 and 2011 and subsequent development capital spending. The 67% increase in average daily production volumes in the Michigan region reflects the full year impact of acquisitions in the second and fourth quarters of 2010. The California region consists of a low-decline asset base and continues to produce at a consistent level. Average daily production volumes in the Williston Basin region reflect the impact of the Company’s acquisitions in this region in 2011.

Gains (Losses) 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 the Company’s commodity derivatives. During the year ended December 31, 2011, the Company had commodity derivative contracts for approximately 101% of its natural gas production and 101% of its oil production, which resulted in realized gains of approximately $257 million (including realized gains on canceled contracts of approximately $27 million). During the year ended December 31, 2010, the Company had commodity derivative contracts for approximately 114% of its natural gas production and 97% of its oil production, which resulted in realized gains of approximately $308 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. If the expected future commodity prices increase compared to the contract prices on the derivatives, unrealized losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives, unrealized gains are recognized. During 2011, expected future oil and natural gas prices decreased, which resulted in net unrealized gains on derivatives of approximately $193 million for the year ended December 31, 2011. During 2010, expected future oil prices increased and expected future natural gas prices decreased, which resulted in net unrealized losses on derivatives of approximately $232 million for the year ended December 31, 2010. 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 $75 million or 47% to approximately $233 million for the year ended December 31, 2011, from approximately $158 million for the year ended December 31, 2010. Lease operating expenses per Mcfe also increased to $1.73 per Mcfe for the year ended December 31, 2011, from $1.64 per Mcfe for the year ended December 31, 2010. Lease operating expenses increased primarily due to costs associated with properties acquired during 2010 and 2011 (see Note 2). Temporary oil handling costs in the Granite Wash formation and higher post-acquisition maintenance costs in the Permian Basin also contributed to the increase.

Transportation Expenses

Transportation expenses increased by approximately $9 million or 45% to approximately $28 million for the year ended December 31, 2011, from approximately $19 million for the year ended December 31, 2010, primarily due to higher production volumes.

General and Administrative Expenses

General and administrative expenses are costs not directly associated with field operations and include costs of employees including executive officers, related benefits, office leases and professional fees. General and administrative expenses increased by approximately $34 million or 35% to approximately $133 million for the year ended December 31, 2011, from approximately $99 million for the year ended December 31, 2010. The increase was primarily due to an increase in salaries and benefits expense of approximately $18 million, driven primarily by increased employee headcount, an increase in unit-based compensation expense of approximately $8 million, an increase in professional services expense of approximately $3 million and an increase in acquisition integration expenses of approximately $3 million. General and administrative expenses per Mcfe decreased to $0.99 per Mcfe for the year ended December 31, 2011, from $1.02 per Mcfe for the year ended December 31, 2010, due to higher production volumes.

Exploration Costs

Exploration costs decreased by approximately $3 million or 54% to approximately $2 million for the year ended December 31, 2011, from approximately $5 million for the year ended December 31, 2010. The decrease was primarily due to lower leasehold impairment expenses on unproved properties.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $95 million or 40% to approximately $334 million for the year ended December 31, 2011, from approximately $239 million for the year ended December 31, 2010. Higher total production volumes were the primary reason for the increased expense. Depreciation, depletion and amortization per Mcfe increased to $2.48 per Mcfe for the year ended December 31, 2011, from $2.46 per Mcfe for the year ended December 31, 2010.

Impairment of Long-Lived Assets

The Company recorded no impairment charge for the year ended December 31, 2011. During the year ended December 31, 2010, the Company recorded a noncash impairment charge of approximately $39 million primarily associated with the impairment of proved oil and natural gas properties related to an unfavorable marketing contract. See Note 1 and "Critical Accounting Policies and Estimates" below for additional information.

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Taxes, Other Than Income Taxes

Taxes, other than income taxes, which consist primarily of severance and ad valorem taxes, increased by approximately $34 million or 74% to approximately $79 million for the year ended December 31, 2011, from approximately $45 million for the year ended December 31, 2010. Severance taxes, which are a function of revenues generated from production, increased by approximately $31 million compared to the year ended December 31, 2010, primarily due to higher commodity prices and higher production volumes. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, increased by approximately $3 million compared to the year ended December 31, 2010, primarily due to property acquisitions in 2011.

Other Income and (Expenses)

	Year Ended December 31, 2011	2010 (in thousands)	Variance
Loss on extinguishment of debt	$ (94,612)	$ —	$ (94,612)
Interest expense, net of amounts capitalized	(259,725)	(193,510)	(66,215)
Realized losses on interest rate swaps	—	(8,021)	8,021
Realized losses on canceled interest rate swaps	—	(123,865)	123,865
Unrealized gains on interest rate swaps	—	63,978	(63,978)
Other, net	(7,792)	(7,167)	(625)
	$ (362,129)	$ (268,585)	$ (93,544)

Other income and (expenses) increased by approximately $94 million during the year ended December 31, 2011, compared to the year ended December 31, 2010. Interest expense increased primarily due to higher outstanding debt during the period and higher amortization of financing fees associated with the 2019 Senior Notes and the 2010 Issued Senior Notes, as defined in Note 6. In addition, in May 2011, the Company entered into a Fifth Amended and Restated Credit Facility, which also resulted in higher amortization of financing fees. For the year ended December 31, 2011, the Company also recorded a loss on extinguishment of debt of approximately $95 million as a result of the redemptions, cash tender offers and additional repurchases of a portion of the Original Senior Notes, as defined in Note 6. See "Debt" in "Liquidity and Capital Resources" below for additional details.

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 states of Texas and Michigan, 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 and Michigan. In addition, certain of the Company's subsidiaries are Subchapter C-corporations subject to federal and state income taxes. The Company recognized income tax expense of approximately $5 million for the year ended December 31, 2011, compared to approximately $4 million for the same period in 2010. Income tax expense increased primarily due to higher income in 2011 from the Company's taxable subsidiaries.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased by approximately $266 million or 36% to approximately $998 million for the year ended December 31, 2011, from approximately $732 million for the year ended December 31, 2010. The increase was primarily due to higher production revenues resulting from higher production volumes and higher commodity prices, partially offset by higher expenses. See "Non-GAAP Financial Measures" on page 58 for a reconciliation of adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP.

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Results of Operations – Continuing Operations

Year Ended December 31, 2010, Compared to Year Ended December 31, 2009

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