Constellation Energy Partners LLC
Form 10-K
March 01, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

OR

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

For the transition period from to .

Commission File Number 001-33147

Constellation Energy Partners LLC

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**11-3742489**
(State of organization)	**(I.R.S. Employer Identification No.)**
1801 Main Street, Suite 1300 **Houston, Texas**	**77002**
(Address of Principal Executive Offices)	**(Zip Code)**

Telephone Number: (832) 308-3700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Units representing Class B Limited Liability Company Interests	NYSE Amex LLC

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ 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 ¨

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

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

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. (Check one):

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	x

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

Aggregate market value of Constellation Energy Partners LLC Common Units, without par value, held by non-affiliates as of June 30, 2011 was approximately $46,110,880 based upon New York Stock Exchange Arca composite transaction closing price.

Indicate the number of shares outstanding of each of the registrant s classes of common stock, as of the latest practicable date.

Common Units outstanding on February 29, 2012: 23,712,857 common units.

Documents Incorporated by Reference: None

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PART I

Item 1. Business

Overview

We are a limited liability company formed in 2005 to acquire oil and natural gas reserves. We are focused on the acquisition, development and production of onshore oil and natural gas properties in the United States. Our primary business objective is to create long-term value and to generate stable cash flows allowing us to make quarterly distributions to our unitholders. All of our proved reserves are located in the Black Warrior Basin in Alabama, the Cherokee Basin in Kansas and Oklahoma, the Woodford Shale in the Arkoma Basin in Oklahoma and the Central Kansas Uplift in Kansas and Nebraska. We operate our oil and natural gas properties as one business segment: the exploration, development and production of oil and natural gas. Our total estimated proved reserves at December 31, 2011 were approximately 201.3 Bcfe, approximately 76% of which were classified as proved developed, and 97% of which are natural gas and 3% of which are oil. At December 31, 2011, we owned approximately 2,785 net producing wells. Our total average proved reserve-to-production ratio is approximately 15.3 years and our portfolio decline rate is 13 to 15 percent based on our estimated proved reserves at December 31, 2011 and production for the month ended December 31, 2011.

We completed our initial public offering on November 20, 2006 and our Class B common units are listed on the NYSE Amex LLC (NYSE Amex) under the symbol CEP.

Unless the context requires otherwise, any reference in this Annual Report on Form 10-K to Constellation Energy Partners, we, our, us, CEP, the Company means Constellation Energy Partners LLC and its subsidiaries. References in this Annual Report on Form 10-K to Constellation, CCG, CEPH, and CHI are to Constellation Energy Group, Inc., Constellation Energy Commodities Group, Inc., Constellation Energy Partners Holdings, LLC, and Constellation Holdings, Inc., respectively. References in this Annual Report on Form 10-K to PostRock and CEPM are to PostRock Energy Corporation and its subsidiary Constellation Energy Partners Management, LLC, respectively.

Business Strategies

Our primary business objective is to create long-term value and to generate stable cash flows allowing us to make quarterly distributions to our unitholders. We plan to achieve our objective by executing our business strategy, which is to:

- organically grow our business by increasing reserves and production through what we believe to be low-risk development drilling that focuses on capital efficient production growth and oil opportunities on our existing properties;
- reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient hedging programs; and
- make accretive acquisitions of oil and natural gas properties characterized by a high percentage of proved developed oil and natural gas reserves with long-lived, stable production and low-risk drilling opportunities.

Black Warrior Basin

The Black Warrior Basin is one of the oldest and most prolific coalbed methane basins in the country. The multi-seam vertical wells in the basin range from 500 to 3,700 feet deep, with coal seams averaging a total of 25 to 30 feet of net pay per well. Coalbed methane wells are generally shallower and produce less gas than conventional natural gas wells, require pumping units to remove the water from the wells, which we refer to as dewatering, and require fracturing to enhance production. These wells also tend to start producing gas and water immediately upon completion, with production usually increasing as the well is dewatered. However, production rates from newly drilled and completed wells in the Black Warrior Basin do not always increase as the formation dewaters. Once dewatered, coalbed methane wells often demonstrate fairly constant production rates for up to five years and then production rates start declining. Wells in the area usually cost approximately $500,000 to drill and complete. Typical coalbed methane wells produce over a period of 20 to over 50 years and on average have less favorable economic characteristics than conventional gas wells. We generally own a 100% working interest (an approximate 75% average net revenue interest) in our wells in the Black Warrior Basin, where we had 507 producing natural gas wells as of December 31, 2011.

The Black Warrior Basin is located in western Tuscaloosa County and Pickens County, Alabama, and encompasses a gross surface area of approximately 109 square miles. The field has been primarily developed on 80-acre spacing. The State of Alabama has approved either 40-acre or 80-acre spacing field-wide. We are currently developing our properties in the field on both 40- and 80-acre spacing. The field has seven compressor stations with 800-1,200 horsepower compressors, approximately 170 miles of gas gathering lines (wells to header) and approximately 25 miles of transportation lines (header to compressor). In addition, there are approximately 152 miles of water gathering pipes and 28 miles of water transportation pipes.

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A majority of our wells were drilled in the basin before 1992 in order to take advantage of certain tax credits. One of our typical well sites consists of a single gas well and associated gas/water separators connected via subsurface piping. Gas flows from the wellhead to compressor facilities, where over 85% of the gas is routed to a natural gas pipeline operated by Southern Natural Gas Company (SONAT). The remaining natural gas is routed to the Southcross Alabama Gathering System, L.P. pipeline (Southcross Alabama). Water produced from our wells is transferred via a facility pipeline to one of our three wastewater treatment facilities, where particulates are removed by settling and the water is then discharged into the Black Warrior River in accordance with effluent standards established by the Alabama Department of Environmental Management (ADEM) and our National Pollutant Discharge Elimination System (NPDES) permits. In addition, there are three saltwater disposal wells that are not currently in use.

Our estimated proved reserves in the Black Warrior Basin at December 31, 2011 were approximately 84.9 Bcfe, approximately 88% of which were classified as proved developed and all of which are natural gas.

Cherokee Basin

The Cherokee Basin is located in the Mid-Continent region in southern Kansas, northern Oklahoma, and western Missouri. It is the eighth largest coalbed methane basin in the United States and covers approximately 26,500 square miles. Production of coalbed methane gas has been ongoing in the basin since the late 1980s. The predominant production is natural gas produced from coals and shales.

There are multiple producing coal zones in the Cherokee Basin including the Rowe, Riverton, Weir-Pitt, and Dawson zones. The carbonaceous shale zone known as the Mulky/Iron Post has been a favored recompletion target for many operators because its presence in a majority of the wells is shallower than most main objective pay zones, and most of the time it adds moderate cash flow. In addition, there are other productive shale zones, as well as conventional sandstone and limestone potential that can add natural gas and oil production.

The individual producing zones are generally 1 to 4 feet thick and appear sometimes as thicker coal and shale intervals. When vertical wells are drilled, these zones need to be hydraulically fractured to stimulate production. The coals in the basin are believed to be near complete saturation such that some gas production is almost immediate. However, as in the Black Warrior Basin, a period of dewatering is required to relieve the pressure on the coals to allow them to produce at their maximum rate. For this reason, pumping units are placed on each well. These units will periodically pump off the water which has accumulated in the well so that the coals can continue to produce while the water is injected into a nearby injection well.

Producing coalbed methane zones get deeper moving from east to west across the Cherokee Basin. Portions of Nowata County, Oklahoma produce from depths that range from about 700 feet to about 1,300 feet in depth. Wells in this area usually cost less than $170,000 to drill and complete. This is in contrast to coalbed methane producing zones in Osage County, Oklahoma that range from about 900 feet to about 2,700 feet in depth. Wells in this area usually vary in cost from $300,000 to in excess of $450,000 to drill and complete. Certain wells do offer the potential opportunity for an oil completion. An oil completion can require additional costs such as a tank battery. Offsetting our lower drilling costs are the relatively low reserves and low daily production rates per well. Typical coalbed methane wells produce over a period of 20 to over 50 years and on average have less favorable economic characteristics than conventional gas wells. A typical oil completion in these areas declines over one to two years and then produces at a steady rate similar to a coalbed methane well.

At December 31, 2011, we owned approximately 2,261 net producing wells in the Cherokee Basin. The gas coming from our producing wells is low pressure due to the shallow producing formations. Therefore, compression is needed to move the gas to point of sale. We operate in excess of 20 booster compressors and stations to get our natural gas to sales points owned by ONEOK Gas Transportation, L.L.C., Scissortail Energy, LLC, Enogex Gas Gathering & Processing, LLC, Enogex Inc., and Southern Star Central Gas Pipeline, Inc. We operate a substantial portion of our production in the Cherokee Basin. We also own a 50% working interest in most wells operated by Bullseye Operating, L.L.C. (Bullseye) and a 50% interest in Bullseye itself. Bullseye operates approximately 500 gross wells in Washington and Nowata Counties in Oklahoma and sells its production through the Cotton Valley producers cooperative, Cotton Valley Compression, L.L.C. Our average gross working interest in our Cherokee Basin properties is approximately 80%, with our average gross working interest in our operated properties being approximately 100% and our average gross working interest in our non-operated Cherokee Basin properties being approximately 50%.

Because minimizing costs is important in coalbed methane development, our typical producing location consists of a small pumping unit, gas/water separator and a meter. Both gas and water are gathered via underground piping to a central gathering area where the gas is treated and compressed for sale and the water is injected or held for hauling.

Our estimated proved reserves in the Cherokee Basin at December 31, 2011 were approximately 110.7 Bcfe, approximately 66% of which were classified as proved developed and 95% of which were natural gas and 5% of which were oil.

Woodford Shale

The Woodford Shale is located in the Arkoma Basin in southern Oklahoma. We own 82 well bores, or approximately 9 net producing wells, located in Coal and Hughes counties. This area is gas-rich and is characterized by multiple productive zones. The production of natural gas in the Woodford Shale comes from shale rock that has been stimulated through fracturing jobs after a horizontal well has been drilled. Woodford Shale wells are typically 6,000 to 11,000 feet deep and cost approximately $3.3 million on average to drill and complete with multiple fracs required. The gas-bearing shale section ranges from 120 to 200 feet thick. As of December 31, 2011, our 82 wells had an average gross working interest of 11.3% and an average net revenue interest of 9.1%. Approximately 90% of the wells are operated by affiliates of Devon Energy Corporation (Devon) and Newfield Exploration Mid-Continent, Inc. (Newfield), with the remaining wells operated by three additional companies. We do not have any additional drilling or leasehold rights associated with our Woodford Shale properties and expect declining production rates and limited future capital expenditures for these wells.

Our estimated proved reserves in the Woodford Shale at December 31, 2011 were approximately 5.2 Bcfe, all of which were classified as proved developed and all of which were natural gas.

Central Kansas Uplift

The Central Kansas Uplift is an oil prone region located in Kansas and southern Nebraska. As of December 31, 2011, we had a gross acreage position of 4,345 acres, or approximately 1,050 net acres and we owned 39 gross wells, or approximately 8 net producing wells. Over 2 billion barrels of oil have been produced in this region from multiple horizons. The Ordovician age Arbuckle Formation and the upper Pennsylvanian age Lansing Kansas City reservoirs are the primary targets. Multiple completions per wellbore are common and the typical carbonate reservoirs are stimulated with an inexpensive acid treatment. Drilling depth for this region ranges from 3,500 feet to 4,900 feet depending on targets and location. Wells in this region typically cost approximately $450,000 to drill and complete.

Murfin Drilling Company, Inc., an experienced oil producer in Kansas, operates all of our wells in this region. Several proven undeveloped locations exist on the acreage and behind pipe opportunities exist in several well bores. The average gross working interest in the wells is approximately 21% and the average net revenue interest is approximately 17%.

Our estimated proved reserves in the Central Kansas Uplift at December 31, 2011 were approximately 0.5 Bcfe, approximately 88% of which were classified as proved developed and all of which were oil.

Proved Oil and Natural Gas Reserves

The following table reflects our estimates of proved oil and natural gas reserves based on the Securities and Exchange Commission (SEC) definitions that were used to prepare our financial statements for the periods presented. The Standardized Measure values shown in the table are not intended to represent the current market values of our estimated proved oil and natural gas reserves.

Reserve data:	**2011**	**2010**	**2009**
Estimated proved reserves:			
Oil (MMBbl)	0.9	0.5	0.3
Natural gas (Bcf)	195.7	166.0	129.4
Total proved reserves (Bcfe)	201.3	169.0	131.2
Estimated proved developed reserves:			
Oil (MMBbl)	0.6	0.4	0.3
Natural gas (Bcf)	148.7	124.9	110.3
Total proved developed reserves (Bcfe)	152.6	127.6	112.1
Estimated proved undeveloped reserves:			
Oil (MMBbl)	0.3	0.1	0.0
Natural gas (Bcf)	46.9	41.1	19.1

Total proved undeveloped reserves (Bcfe)	48.7	41.4	19.1
Proved developed reserves as a percent of total reserves	76%	76%	85%
Standardized Measure (in millions) (a)	$ 160.7	$ 131.7	$ 97.2

(a) Standardized Measure is the present value of estimated future net revenues to be generated from the production of proved reserves. It is determined using SEC-required prices and costs in effect as of the time of estimation without giving effect to non-property related expenses (such as general and administrative expenses or debt service costs) and discounted using an annual discount rate of 10%. Our Standardized Measure does not include the impact of derivative transactions or future federal income taxes because we are not subject to federal income taxes.

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Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production. The SEC provides a complete definition of proved reserves, proved developed reserves and proved undeveloped reserves in Rule 4-10(a) of Regulation S-X.

At December 31, 2011, 2010, and 2009, Netherland, Sewell & Associates, Inc. (NSAI), an independent petroleum engineering firm, prepared an estimate of all our proved reserves. We used NSAI s estimates of our proved reserves to prepare our financial statements. NSAI maintains a degreed staff of highly competent technical personnel. The average experience level of their technical staff of engineers, geoscientists, and petrophysicists exceeds 20 years, including 5 to 15 years with a major oil company. We maintain an internal technical staff of engineers and geoscience professionals which have an average experience level that exceeds 27 years. Our activities with NSAI are coordinated by a reservoir engineer employed by us who has approximately 30 years of experience in the oil and gas industry and an engineering degree from the University of Tennessee and a masters of business administration from the University of New Orleans. He is a member of the Alabama Coalbed Methane Association and the Society of Petroleum Engineers. He has prior reservoir engineering and reserves management experience at Exxon Mobil Corporation, Dominion Resources and Hilcorp Energy. He has extensive experience in managing oil and gas reserves processes. He serves as the key technical person on our internal reserves committee, which reviews the reserve reports prepared by NSAI before the reports are reviewed by our audit committee of our board of managers and approved by our board of managers.

We have a successful track record of developing our proved undeveloped reserves in both the Cherokee Basin and in the Black Warrior Basin. We do not rely on any proprietary technology to drill our development wells. Since our formation in 2005, we have drilled 365 development wells on our proved undeveloped locations and intend to continue this pattern of development drilling. Based on our structure as a limited liability company and our current business plans, our forecasted cash flow over the next 5 years is expected to be sufficient to fund this type of development drilling program on certain of our proved undeveloped locations. Using the SEC rules for estimating proved reserves, we only recorded proved undeveloped locations that are scheduled to be drilled within the next 5 years. Any locations that are identified to be drilled beyond 5 years are classified as probable or possible reserves. We record our proved undeveloped locations typically at one offset location but we can also record proved undeveloped locations on one section surrounding existing production subject to available infrastructure. We have the right to develop locations under our concession agreement with the Osage Nation in Osage County, Oklahoma, subject to its terms and conditions, until 2020 and we have leasehold availability for our other proved undeveloped locations. During 2012, we currently expect to drill 80 to 100 net wells and recompletions in the Black Warrior Basin and in the Cherokee Basin, which is a level of drilling activity that we anticipate to be sufficient to develop our 2012 inventory of proved undeveloped locations.

The following table summarizes our inventory of proved undeveloped locations:

		Year PUD Is Scheduled To Be Developed				
Year PUD Originally Booked		**2012**	**2013**	**2014**	**2015**	**2016**
Total PUD Booked In Reserve Report	Number of Locations	41	96	89	103	113
	Equivalents-Bcfe	3.8	10.8	10.2	11.6	12.3
	Capital Estimate-$millions	$ 11.2	$ 16.4	$ 15.1	$ 17.0	$ 18.4

Our estimates of total proved undeveloped reserves increased from 41.4 Bcfe in 2010 to 48.7 Bcfe in 2011, or by 7.3 Bcfe. This change was the result of the addition of 7.9 Bcfe of proved undeveloped reserves in the Cherokee Basin because of 1.2 Bcfe of increased oil opportunities that are in our 2012 drilling program and 6.7 Bcfe of reserve revisions primarily because of the impact of lower operating expenses. This increase was offset by a 0.6 Bcfe decline in our Black Warrior proved undeveloped reserves, primarily as a result of the impact of lower natural gas prices. The data in all of the above tables represents estimates only. Oil and natural gas reserve engineering is an inherently subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering, geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately produced. No reserve data has been filed or included with reports to any governmental agency other than the SEC.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The Standardized Measure shown should not be considered the current market value of our reserves. The 10% discount factor used to calculate present value, which is required, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

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Oil and Natural Gas Prices

We have generally sold our natural gas production based upon an index price reported in *Inside FERC s Gas Market Report* (Inside FERC) or at spot market prices applicable to the location of our natural gas production. Our realized pricing is primarily driven by the Inside FERC price for Southern Natural Gas Co. (Louisiana) (SONAT Inside FERC price) with respect to our properties in the Black Warrior Basin, the Inside FERC prices for CenterPoint Energy Gas Transmission Co. (East), Natural Gas Pipeline Co. of America (Midcontinent), ONEOK Gas Transportation LLC (Oklahoma), Panhandle Eastern Pipe Line Co. (Texas, Oklahoma) and Southern Star Central Gas Pipeline Inc. (Texas, Oklahoma, Kansas) with respect to our properties in the Cherokee Basin, the Inside FERC price for CenterPoint Energy Gas Transmission Co. (East) with respect to our properties in the Woodford Shale, and the applicable monthly average posted oil price with respect to our properties in the Central Kansas Uplift. The following table summarizes year-end closing prices for the major indexes applicable to our business:

	Prices on January 1,		
Market Prices:	**2012**	**2011**	**2010**
Natural gas price NYMEX (Henry Hub)	$ 3.08	$ 4.22	$ 5.82
Natural gas price CenterPoint Energy Gas Transmission Co. (East)	$ 2.97	$ 3.96	$ 5.67
Natural gas price Natural Gas Pipeline Co. of America (Midcontinent)	$ 3.01	$ 3.96	$ 5.77
Natural gas price ONEOK Gas Transportation LLC (Oklahoma)	$ 3.04	$ 4.10	$ 5.79
Natural gas price Panhandle Eastern Pipe Line Co. (Texas, Oklahoma)	$ 2.99	$ 3.93	$ 5.73
Natural gas price Southern Natural Gas Co. (Louisiana)	$ 3.09	$ 4.27	$ 5.87
Natural gas price Southern Star Central Gas Pipeline Inc. (Texas, Oklahoma, Kansas)	$ 3.02	$ 3.88	$ 5.79
Oil price West Texas Intermediate Cushing	$ 98.83	$ 91.38	$ 79.39

We enter into derivative transactions in the form of hedging arrangements to reduce the impact of oil and natural gas price volatility on our cash flow from operations. Currently, we use fixed price swaps to hedge oil and natural gas prices. We also use basis swaps to limit our exposure to differences between the NYMEX natural gas price and the price at the location where we sell our natural gas. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of fluctuating commodity prices on our cash flow from operations for those periods. All of our commodity derivative positions are outlined in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Cash Flow From Operations-Open Commodity Hedge Positions.

Production and Price History

The following table sets forth information regarding net production of natural gas and certain price and cost information for each of the periods indicated:

	For the year ended December 31, 2011	For the year ended December 31, 2010	For the year ended December 31, 2009
Net Production:			
Natural gas production (MMcf)	13,047	14,670	16,590
Oil and liquids production (MBbl)	105	61	78
Total production (MMcfe)	13,679	15,037	17,061
Average daily production (Mcfe/d)	37,477	41,197	46,742
Average Sales Prices:			
Natural gas price per Mcf with hedge settlements [(a)]	$ 10.25	$ 7.09	$ 7.16
Natural gas price per Mcf without hedge settlements	$ 3.96	$ 4.34	$ 3.58
Oil and liquids price per Bbl with hedge settlements	$ 103.52	$ 76.97	$ 58.28
Oil and liquids price per Bbl without hedge settlements	$ 97.76	$ 76.97	$ 58.28
Total price per Mcfe with hedge settlements [(a)]	$ 10.57	$ 7.23	$ 7.22
Total price per Mcfe without hedge settlements	$ 4.53	$ 4.54	$ 3.75
Average Unit Costs Per Mcfe:			

Field operating expenses[(b)]	$	2.25	$	2.26	$	2.15
Lease operating expenses	$	2.04	$	2.05	$	1.97
Production taxes	$	0.21	$	0.21	$	0.18
General and administrative expenses	$	1.21	$	1.35	$	1.08
Depreciation, depletion and amortization	$	1.62	$	5.67	$	4.17
Asset impairments	$	0.21	$	18.12	$	0.30

(a) Price per Mcfe including hedges includes realized and unrealized mark-to-market losses on derivative transactions that did not qualify for hedge accounting treatment. The average sales price for natural gas per Mcf with hedge settlements for 2011 includes the $41.3 million impact of our hedge restructuring.

(b) Field operating expenses include lease operating expenses (average production costs) and production taxes.

The following table sets forth information regarding net production of oil and natural gas and selected price and cost information by geographic region for each of the periods indicated:

	Black Warrior Basin			Cherokee Basin			Woodford Shale		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Natural gas production (MMcf)	4,514	4,703	4,887	7,924	9,400	10,932	609	567	773
Oil and liquids production (MBbl)				105	61	78			
Total production (MMcfe)	4,514	4,703	4,887	8,556	9,767	11,401	609	567	773
Natural gas price per Mcf without hedge settlements	$ 4.13	$ 4.50	$ 4.07	$ 3.97	$ 4.20	$ 3.34	$ 4.18	$ 5.30	$ 3.60
Oil and liquids price per Bbl without hedge settlements				$ 97.76	$ 76.97	$ 58.28			
Total price per Mcfe without hedge settlements	$ 4.13	$ 4.50	$ 4.07	$ 4.77	$ 4.52	$ 3.60	$ 4.18	$ 5.30	$ 3.60
Lease Operating Expense per Mcfe	$ 1.58	$ 1.51	$ 1.47	$ 2.33	$ 2.33	$ 2.19	$ 1.46	$ 1.58	$ 1.86

Productive Wells

The following table sets forth information at December 31, 2011 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of producing commercial quantities of oil or natural gas, including oil and natural gas wells awaiting pipeline connections to commence deliveries. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Natural Gas December 31, 2011		Oil December 31, 2011	
	Gross	Net	Gross	Net
Operated	2,375	2,307	134	134
Non-operated	713	324	62	20
Total	3,088	2,631	196	154

Drilling Activity

The following table sets forth information with respect to oil and natural gas wells drilled and completed by us during the years ended December 31, 2011, 2010 and 2009. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that are capable of producing commercial quantities of oil or natural gas, regardless of whether they produce a reasonable rate of return. No exploratory wells were drilled during the years ended December 31, 2011, 2010 or 2009.

	Year Ended December 31, 2011	2010	2009	Wells in Progress as of December 31, 2011
Gross:				
Development				
Productive	35	17	60	10
Dry	1		1	
Recompletions	49	14	17	
Total	85	31	78	10
Net:				
Development				
Productive	35	17	60	10
Dry	1		1	
Recompletions	49	14	17	
Total	85	31	78	10

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2011 relating to our leasehold acreage.

	Developed Acreage[(a)]		Undeveloped Acreage[(b)]	
	Gross[(c)]	Net[(d)]	Gross[(c)]	Net[(d)]
Total	262,548	249,666	31,376	28,270

(a) Developed acres are acres pooled within or assigned to productive wells/units.

(b) Undeveloped acres are acres on which wells have not been drilled or acres that have not been pooled into a productive unit.

(c) A gross acre is an acre in which a working interest is either fully or partially leased. The number of gross acres may include minerals not under lease as a result of leasing some but not all joint mineral owners under any given tract.

(d) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Our acreage includes areas leased under a concession agreement that we have with The Osage Nation in Osage County, Oklahoma, which provides us with the exclusive right to lease for coalbed methane on up to 560,000 acres within Osage County and the exclusive right for a period of ninety (90) days after drilling a coalbed methane well on any such acreage to lease for oil and gas on such acreage. Generally, we have the right each year to elect to license up to a certain amount of acreage under the concession agreement for such year for a specified license payment, and a license must be obtained before we then lease the acreage. During the term of the concession agreement, however, we have the exclusive right to lease the acreage covered thereunder for coalbed methane unless we notify The Osage Nation in writing that we have no intention to lease any particular acreage. Our concession agreement with The Osage Nation is in four phases as follows: (i) Phase I (four year term of January 1, 2005 through December 31, 2008) during which not less than 440 production wells were to have been drilled and completed; (ii) Phase II (four year term of January 1, 2009 through December 31, 2012) during which a cumulative of not less than 680 production wells shall be drilled and completed; (iii) Phase III (four year term of January 1, 2013 through December 31, 2016) during which a cumulative of not less than 920 production wells shall be drilled and completed; and (iv) Phase IV (four year term of January 1, 2017 through December 21, 2020) during which a cumulative of not less than 1,160 production wells shall be drilled and completed, such that not less than a total of 1,160 production wells shall be drilled in Phases I through IV. Generally, in addition to the drilling and completion of a producing well counting as a production well, the drilling of two dry holes are counted as one production well, a recompletion of an existing wellbore is counted as one production well, a horizontal well is counted as two production wells and a salt water disposal well is counted as one production well under the concession agreement (hereinafter production well credits). As of December 31, 2011, we believe we have earned approximately 740 total production well credits and our total developed and undeveloped leased acreage totaled approximately 65,920 acres. This level of credits is sufficient to achieve the specific drilling targets under the concession agreement through Phase II, which ends December 31, 2012. If the drilling requirement for a particular phase is not met, we have the option to make a payment equal to the shortfall of production wells required to be drilled multiplied by $50,000 per well in order to be deemed to have complied with the requirement for that phase. If the drilling requirement of a particular phase were not met (either through drilling of production wells or payment as described above), The Osage Nation s sole remedy would be the termination of the concession agreement at the expiration of the then current phase, provided that such termination would have no effect upon our wells already drilled and the leases that we have acquired that are producing in paying quantities. We believe The Osage Nation has granted at least two concessions for the drilling of conventional oil and gas on acreage which overlaps certain of the acreage covered by our earlier granted concession and it has taken the position that we are not entitled to conventional oil and gas leases under the terms of our concession agreement where we have not drilled a coalbed methane well first.

Leases

Our leases are concentrated in Oklahoma (78%), Alabama (15%), and Kansas (7%). We have approximately 662 leases in the Black Warrior Basin on over 43,633 net acres. The typical oil and gas lease agreement covering our Black Warrior Basin properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on or pooled with the leased property. There are other burdens affecting certain of the leases in the form of overriding royalty interests. On our properties in the Black Warrior Basin, we own a 100% working interest, or an approximate 75% net revenue interest, in substantially all our developed acreage. Depending on the location of a particular well, the total lease burden is generally 25%, generally corresponding to a 75% lease net revenue interest to us. In some instances, our lease net revenue interest may be as high as 83%. We have approximately 1,626 leases in the Cherokee Basin on approximately 233,285 net acres. Our concession agreement with the Osage Nation in Osage County, Oklahoma provides us the exclusive right to lease for coalbed methane wells on approximately 560,000 net acres within the Osage Nation until its expiration in 2020 or any earlier termination according to its terms and conditions. We will earn new acreage within the concession as we drill additional wells. The typical oil and gas lease agreement covering our other Cherokee Basin properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on or pooled with the leased property. In the Cherokee Basin, depending on the location of a particular well, the total lease burden on our operated properties is generally 20%, generally corresponding to a 80% net revenue interest to us, and on our non-operated properties is generally a 40% net revenue interest. We have 65 leases with a gross acreage position of 4,345 acres in the Central Kansas Uplift, or approximately 1,050 net acres. We have no leasehold rights associated with our 82 well bores in the Woodford Shale.

Under the oil and gas lease agreements covering our productive wells, such leases have generally been perpetuated beyond their stated lease term and generally will not expire unless and until associated production ceases. Such leases are said to be held by production and do not require us to make lease payments beyond the royalty amount stipulated by each lease. The area held by production from a particular well is typically held by lease or applied to a pooled unit for such well or as specified under state law. Barring establishment of commercial production, most of our leases not currently held by production will expire. Approximately 10%, 10% and 7% of our total net undeveloped acreage of 28,270 acres is held under leases that have remaining primary terms expiring in 2012, 2013 and 2014, respectively. Of these expiration amounts in 2012, 2013, and 2014, approximately 75%, 71%, and 96%, respectively, apply to our concession agreement with the Osage Nation. If these leases do expire, we have the exclusive right to acquire a new coalbed methane lease on any expired acreage under our concession agreement with the Osage Nation until its expiration in 2020 or any earlier termination according to its terms and conditions. Substantially all of the remaining expiring acreage in all three years is primarily located in Kansas and Oklahoma.

Operations

General

We are the operator of approximately 88% of the 2,785 net wells in which we own an interest. The administration and operation of our properties may be divided into the following functions:

Executive Management

Our executive management team develops and approves our business plans. They report directly to our board of managers, which is composed of three independent managers and two managers appointed by the holder of our Class A units. We have the responsibility for the overall operations of our fields and developing our drilling programs and other production enhancement opportunities. Field operations and the related technical support services including geology, engineering, land administration, and accounting are conducted by employees of one of our subsidiaries. Our employees and contractors approve the design and the development, maintenance, recompletion and workover for all of the wells in our fields. Our drilling programs are designed by us and implemented by various contractors. We do not own drilling rigs or other oil field services equipment used for drilling wells on our properties.

Field Operations

Our day-to-day operations in the Black Warrior Basin are conducted by field employees of one of our subsidiaries under the supervision of our management team. The field operations team has extensive experience in the Black Warrior Basin and has been operating in the Black Warrior Basin since the early 1990s. This group is responsible for the operation of the existing production wells, pipelines, compressors and water handling facilities, as well as interaction with Alabama regulatory authorities with regard to permitting and compliance matters. In addition, they assist with the execution of the drilling and maintenance program and the management of the contractors responsible for the drilling and completion of these wells. We have a field office located in Buhl, Alabama.

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Historically, when we drill new wells in the Black Warrior Basin, the drilling rigs have been provided by and the wells drilled by Pense Bros. Drilling Co., Inc., an established Black Warrior Basin drilling contractor. Other contract vendors conduct the cementing operations, provide well logging services and provide the design for, and execute upon, the well stimulation program. We evaluate our service providers in the basin from time to time.

Our day-to-day operations in the Cherokee Basin are conducted by field employees of one of our subsidiaries under the supervision of our management team. The majority of the field operations team is composed of employees that were transitioned to us as a result of the acquisitions we made in the basin. This group is responsible for the operation of the existing production wells, pipelines, compressors and water handling facilities, as well as interaction with regulatory authorities with regard to permitting and compliance matters. In addition, they assist with the execution of the drilling and maintenance programs and the management of the contractors responsible for the drilling and completion of these wells. We currently have field offices located in Coffeyville, Kansas, Dewey, Oklahoma and Skiatook, Oklahoma.

Historically, when we drill new wells in the Cherokee Basin, our construction and roustabout services have been provided by various third party vendors. The drilling rigs have been provided by and our vertical wells drilled by Pense Bros. Drilling Co., Inc. and our directional drilling done by Scientific Drilling International, Inc. Other contract vendors conduct the cementing operations, provide well logging services and provide the design for, and execute upon, the well stimulation program. We evaluate our service providers in the basin from time to time.

For our 82 well bores located in the Woodford Shale, the operators of the properties primarily Devon and Newfield conduct all operations on our behalf. For our 39 non-operated wells located in the Central Kansas Uplift, Murfin Drilling Company Inc., the operator, conducts all operations on our behalf.

Geology and Engineering

Our technical team is located in our technical office in Tulsa, Oklahoma, and at our corporate headquarters in Houston, Texas. We have retained engineers, geologists and consultants who have experience in drilling and producing coalbed methane reserves. As a result, we have the ability to draw from a base of experienced and capable talent to select drilling locations and completion approaches to improve productivity and generate and test new ideas to improve production and reserves from existing wells through the use of recompletions, optimizing compression and gathering systems. NSAI, an independent petroleum engineering firm, has been retained to prepare the estimates for all of our proved reserves.

Land Administration

Our lease positions and our concession with the Osage Nation are managed by our employees with assistance from contract landmen. These employees and landmen provide assistance with management of our current lease positions, acquisitions of new leases, permitting for drilling and laying pipelines as well as negotiating agreements with landowners for the use of their property. We have land staff in our field offices as required, with our land administration function in Houston, Texas.

Revenue Accounting

Our revenue accounting function for all of our properties has been outsourced to Schlumberger, ePrime Services, a Texas-based revenue accounting firm that is a subsidiary of Schlumberger LTD, a supplier of technology, project management, and information solutions to the oil and gas industry. Schlumberger manages the cash flow associated with our interest in the oil and natural gas properties, including the payment of invoices, calculation and payment of royalties, and receipt of revenues from oil and natural gas sales, and provides accounting information used to generate financial statements.

Marketing and Major Customers

We manage our oil and natural gas marketing efforts and actively monitor our credit exposure to our major customers. We currently sell our natural gas produced in the Black Warrior Basin to J.P. Morgan Ventures Energy Corporation and to Southcross Alabama Gathering System, L.P. We currently sell our natural gas produced in the Cherokee Basin to Macquarie Energy LLC, Keystone Gas Corporation, Scissortail Energy, LLC, Cotton Valley Compression, L.L.C., Cherokee Basin Pipeline, LLC, and ONEOK Energy Services Company, L.P. Our oil production in the Cherokee Basin is primarily purchased by Sunoco Partners Marketing and Terminals L.P. and Coffeyville Resources Refining and Marketing, LLC. Our natural gas production in the Woodford Shale and our oil production in the Central Kansas Uplift is marketed by the operators of our properties.

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Hedging and Risk Management Activities

Our hedging and risk management activities are managed by employees of one of our subsidiaries. Their activities are monitored by our risk committee composed of internal employees and quarterly risk reports are made to our board of managers and to the audit committee of our board of managers. We have entered into derivative transactions with banks who participate in our reserve-based credit facility. The derivative transactions are done to reduce our exposure to short-term fluctuations in oil and natural gas prices and interest rates and to achieve more predictable cash flows. None of our derivatives currently require cash collateral and we do not enter into speculative or proprietary trading activities. We also maintain an active insurance program to provide for coverage to insure against various losses and liabilities arising from our operations and drilling activities.

Markets and Competition

We operate in a competitive environment for acquiring properties, marketing oil and natural gas and retaining trained personnel. Many of our competitors have substantially greater financial, technical and personnel resources than ours. As a result, our competitors may be able to outbid us for oil and natural gas properties and exploratory prospects, more competitively price their production, or utilize superior technical resources than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a competitive environment with limited access to capital. There is substantial competition for the limited capital available for investment in the oil and natural gas industry. Neither PostRock and its affiliates nor Constellation and its affiliates are restricted from competing with us.

We are also affected by competition for drilling rigs, completion rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling and completion rigs, equipment, pipe and personnel, which has delayed development drilling activities and has caused significant increases in the prices for this equipment and personnel. We are unable to predict when, or if, such shortages may occur or how they would affect our development and drilling program. To date, however, we have not experienced such shortages. In addition, over the past several years, our field employees have been working with teams of drilling and completion contractors and have developed relationships that should enable us to mitigate the risks associated with equipment availability.

Title to Properties

When we acquire our interests in oil and natural gas properties, we obtain a title opinion or perform a review on the most significant leases in the fields. As a result, title opinions or reviews have been obtained on a significant portion of our properties. In some instances, and as is customary in our industry, we conduct only a cursory review of the title to certain properties on which we do not have proved reserves. To the extent title opinions or other investigations reflect title requirements on those properties, we are typically responsible for curing any material title matters at our expense. We generally will not commence drilling operations on a property until we have cured or waived any such title matters or deemed the title risk sufficiently mitigated to justify proceeding with operations on the property.

We believe that we have satisfactory title to all of our material assets. Title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry. We believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or will materially interfere with our use in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties to operate our business.

Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, state, local, and Native American tribal laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;

restrict the types, quantities and concentrations of various substances, including water and waste, that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;

limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas; and

require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible in the absence of such regulations. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, federal, state, local, and Native American tribal authorities 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 our operating costs.

Environmental laws and regulations that could have a material impact on the oil and natural gas industry and our operations include the following:

Waste Handling

The Resource Conservation and Recovery Act (RCRA), and comparable state laws, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency (EPA), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most other wastes associated with the exploration, development and production of oil and natural gas are currently regulated under RCRA s non-hazardous waste provisions. Certain of our operations are known to bring to the surface naturally occurring radioactive material (NORM) which is accumulated at certain of our facilities in the Black Warrior Basin and is subject to permitting and controls for storage, as well as requirements for proper disposal. We believe our operations are in substantial compliance with the radioactive materials license issued by the State of Alabama Department of Public Health to cover activities associated with NORM. Although we do not believe the current costs of managing any of our wastes are material under presently applicable laws, any future reclassification of oil and natural gas exploration, development and production wastes as hazardous wastes, or more stringent regulation of NORM wastes, could increase our costs to manage and dispose of wastes.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed of, or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease or operate numerous properties that have been used for oil and natural gas exploration and production for a number of years. Although we believe operating and waste disposal practices utilized in the past with respect to these properties were typical for the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges

The Federal Water Pollution Control Act (the Clean Water Act), and comparable state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, impose investigatory or remedial obligations and issue injunctions limiting or preventing our operations for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the Cherokee Basin, water is pumped from producing wells, collected, and

injected into approved salt water disposal wells in the deeper Arbuckle formation. In the Black Warrior Basin, we maintain permits issued pursuant to the Clean Water Act that authorize the discharge of produced waters and similar wastewaters generated as a result of our operations, in accordance with effluent standards established by the ADEM. ADEM is currently developing new effluent standards for discharge of produced water from coalbed methane wells which we will be required to meet when such standards are in effect. While we believe we are in substantial compliance with these permits and the other requirements of the Clean Water Act, we have several ponds used for the treatment and storage of wastewaters in the Black Warrior Basin that were found to have leaked into the subsurface beneath the ponds at some time prior to our ownership. ADEM is aware of these leaks. We replaced certain of the liners beneath these treatment ponds and, under the supervision of ADEM, are monitoring for the presence of chlorides in the subsurface to better determine what cleanup measures, if any, may be required by the ADEM. Based on present information, we do not believe we will incur material costs or penalties in connection with this matter, but there can be no assurance that significant costs will not be incurred if future data reveals elevated levels of chlorides beneath the ponds.

Oil Pollution Act

The Oil Pollution Act was enacted in 1990 to amend the Clean Water Act in large part due to the Exxon Valdez incident. Under the Oil Pollution Act, EPA was directed to promulgate regulations which would create a comprehensive prevention, response, liability and compensation program to deal with oil discharged into U.S. navigable waters. In particular, the regulations developed under the Oil Pollution Act strengthened the requirements that apply to Spill Prevention, Control and Countermeasure Plans. The Oil Pollution Act imposes liability for removal costs and damages resulting from an incident in which oil is discharged into navigable waters and establishes liability for damages for injuries to, or loss of, natural resources.

Air Emissions

The Clean Air Act, and comparable state laws, regulates emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA, ADEM, the Oklahoma Department of Environmental Quality, the Kansas Department of Health and Environment and the Nebraska Department of Environmental Quality have developed, and continue to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. We believe our operations are in substantial compliance with federal and state air emission standards. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, impose investigatory or remedial obligations and issue injunctions limiting or preventing our operations for non-compliance with air permits or other requirements of the federal Clean Air Act and comparable state laws.

The Kyoto Protocol to the United Nations Framework Convention on Climate Change became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol. The United States Congress has not passed legislation directed at reducing greenhouse gas emissions. In December 2009, however, the EPA finalized its endangerment finding for greenhouse gas emissions which determines that the EPA has authority to regulate greenhouse gas emissions under the Clean Air Act. The EPA has adopted rules that require the mandatory reporting of greenhouse gases from large stationary sources of greenhouse gas emissions beginning in 2011 for emissions occurring in 2010. Our operations do not qualify us as a large stationary source of greenhouse gas emission and we do not have a reporting requirement under that rule. Further, under final rules issued by the EPA in November 2010 and subsequent amendments, which requires certain owners and operators of onshore natural gas production to monitor greenhouse gas emissions beginning in 2011 and to report those emissions beginning in 2012, we currently believe that it is not likely that we will have a reporting requirement for greenhouse gases in 2012 and future years for our current source categories. Under such rules, a reporting requirement arises for assorted source categories including production, process, transmission, storage and distribution of oil and natural gas for any source category when 25,000 metric tons of CO_2e or more per year in emissions are emitted. The production category extends to all equipment on wells pads and associated with well pads, including compressors, generators, separators, storage tanks, well drilling and completion equipment, and workover equipment and is to be aggregated on a hydrocarbon sub-basin level.

The EPA has also signaled that it will revise and develop new standards for greenhouse gas emissions that may impose additional limits on the greenhouse gas emissions that a new or modified facility may emit. There may be additional legislation that requires the reporting of greenhouse gas emissions, the reduction of greenhouse gas emissions or increased taxes on greenhouse gas emissions. Some states have already adopted legislation addressing greenhouse gas emissions from various sources, primarily power plants. The oil and natural gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions or increased taxes on greenhouse gas emissions would impact our business.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over certain hydraulic fracturing practices and has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with initial results of the study anticipated to be available by late 2012 and final results by 2014. Further, the Department of the Interior has released draft regulations governing hydraulic fracturing on federal and Native American oil and gas leases which would require lessees to file for approval of well stimulation work before commencement of operations and require well operators to disclose the trade names and purposes of additives used in the fracturing fluids. Legislation has been introduced, but not adopted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Currently, no states in which we utilize hydraulic fracturing have adopted these regulations. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing hydraulic fracturing would impact our business.

OSHA and Other Laws and Regulation

We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state laws. The OSHA hazard communications standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state laws require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements.

Our operations in the Black Warrior Basin in Alabama are subject to the rules and regulations of the State Oil and Gas Board of Alabama Governing Coalbed Methane Gas Operations and these rules and regulations are found in the State Oil and Gas Board of Alabama Administrative Code. Our operations in the Cherokee Basin and in the Woodford Shale in Oklahoma are subject to the rules and regulations of the Oklahoma Corporation Commission, Oil & Gas Conservation Division. Our operations in the Cherokee Basin and the Central Kansas Uplift in Kansas are subject to the rules and regulations of the Kansas Corporation Commission, Oil & Gas Conservation Division. Our operations in the Central Kansas Uplift in Nebraska are subject to the rules and regulations of the Nebraska Oil and Gas Conservation Commission. We believe we are in substantial compliance with these rules and regulations.

We believe that we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements should not have a material adverse impact on our financial condition and results of operations. As of December 31, 2011, we had no accrued environmental obligations. We are not aware of any environmental issues or claims that will require material capital expenditures or that will otherwise have a material impact on our financial position or results of operations. However, we cannot predict how future environmental laws and regulations may impact our operations, and therefore cannot provide assurance that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial condition, results of operations or ability to pay distributions to our unitholders.

Employees

As of February 29, 2012, our subsidiary, CEP Services Company, Inc., had 117 employees. None of these employees are subject to a collective bargaining agreement.

Offices

We are headquartered in Houston, Texas. We also maintain a technical office in Tulsa, Oklahoma, and we have field offices located in Buhl, Alabama, Coffeyville, Kansas, Dewey, Oklahoma, and Skiatook, Oklahoma. We own the field office buildings and land in Alabama, Kansas, and Oklahoma.

Available Information

Our internet address is *http://www.constellationenergypartners.com*. We make our website content available for informational purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Annual Report on Form 10-K. We make available free of charge on or through our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC maintains an internet website that contains these reports at *http://www.sec.gov*. The public may read and copy any materials that we file with the SEC 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) 723-0330.

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Item 1A. Risk Factors

Risks Related to Our Business

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our financial condition 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 and natural gas 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 cancelled as a result of other factors, including: the high cost, shortages or delivery delays of drilling rigs, equipment, labor and other services; unexpected operational events and drilling conditions; decreases in oil and natural gas prices; limitations in the market for oil and natural gas; adverse weather conditions; facility or equipment malfunctions; accidents; title problems; piping, casing or cement failures; compliance with environmental and other governmental requirements; unusual or unexpected geological formations; loss or damage to oilfield drilling and service tools; loss of drilling fluid circulation; formations with abnormal pressures; environmental hazards, such as gas leaks, oil spills, compressor incidents, pipeline ruptures and discharges of toxic gases; water pollution; fires; accidents or natural disasters; blowouts, craterings and explosions; uncontrollable flows of oil, natural gas or well fluids; and loss or theft of data due to cyber attacks.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction or loss of property, natural resources, equipment, and data, pollution, environmental contamination, loss of wells and regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. 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 or the insurance companies from which we obtain insurance could become credit impaired and unable to pay our claims. The occurrence of an event that is not fully covered by insurance could adversely affect our business, financial condition, results of operations and ability to pay distributions.

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.

We have identified and scheduled drilling locations for our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our future development drilling program. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. In addition, no proved reserves are assigned to any of the potential drilling locations we have identified and therefore, there may be greater uncertainty with respect to the likelihood of drilling and completing successful commercial wells at these potential drilling locations. Our final determination of 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 or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified, which could have a significant adverse effect on our financial condition, results of operations and ability to pay distributions.

We must make sufficient maintenance capital expenditures to maintain our asset base. Unless we replace the reserves that we produce, our existing reserves will decline, which may adversely affect our production and would adversely affect our cash from operations and our ability to pay distributions to our unitholders.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. In the Cherokee Basin and in the Woodford Shale, coalbed methane production generally declines at a shallow rate after initial increases in production as a consequence of the dewatering process. However, production rates from newly drilled and completed wells in the Black Warrior Basin do not typically increase as the formation dewaters.

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Our production from our existing reserves will decline over time. To offset this decline, we must spend maintenance capital expenditures. During 2011, we spent less than our estimated 2011 maintenance capital expenditures of $23.0 million and our 2011 production decreased from 2010. Because we have spent less than our estimated maintenance capital expenditures in the past three years, our production declined over the past three years. We expect to spend at least $15.0 million in total capital expenditures in 2012, which we anticipate will result in our 2012 production being relatively flat to our production in 2011. If we do not spend this level of capital expenditures or do not spend our capital budget in an effective manner, we may not be able to maintain our asset base and production rates, which could lower our operating cash flows.

Additionally, the rate of decline of our reserves and production reflected in our reserve reports 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. The rate of decline may also be greater than we have estimated due to decreased capital spending or lack of available capital to make capital expenditures. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition, results of operations and ability to pay distributions.

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 and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels and operating and development costs. In addition, in the early stages of a coalbed methane project, it is difficult to predict the production curve of a coalbed methane field. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may prove to be inaccurate. For 2011, 2010 and 2009, an independent petroleum engineering firm prepared the estimates of proved oil and natural gas reserves included in our SEC filings. Over time, engineers may make material changes to reserve estimates taking into account the results of actual drilling and production. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, certain assumptions are made regarding future oil and natural gas prices, production levels and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. For example, if average natural gas prices were to increase by $1.00 per Mcfe, then the Standardized Measure of our proved reserves as of December 31, 2011 would increase from approximately $160.7 million to approximately $295.2 million. Conversely, if average natural gas prices were to decrease by $1.00 per Mcfe, then the Standardized Measure of our proved reserves as of December 31, 2011 would decrease from approximately $160.7 million to approximately $96.1 million. Our Standardized Measure is calculated using unhedged oil and natural gas prices and is determined in accordance with the rules and regulations of the SEC (except for the impact of income taxes as we are not a taxable entity). 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 and natural gas 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 and natural gas reserves.

We base the estimated discounted future net cash flows from our proved reserves on SEC rules. These rules require specific prices and costs to be used when we make an estimate of proved reserves. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- the supply of and demand for oil and natural gas;
- the actual prices we receive for oil and natural gas;
- our actual operating costs in producing oil and natural gas;

the amount and timing of our capital expenditures;

the amount and timing of our actual production; and

changes in governmental regulations or taxation.

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The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from our proved reserves, and thus their actual present value. In addition, the 10% discount factor used when calculating our 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. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations, financial condition and ability to pay distributions.

Declines in oil and natural gas prices may result in additional write-downs of our asset carrying values.

Lower oil and natural gas prices may not only decrease our revenues, profitability and cash flows, but also may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make additional substantial downward adjustments to our estimated proved reserves or a write-down in the carrying value of our assets. For example, in 2010 because of a substantial decline in natural gas prices, we wrote down the carrying value of our assets by approximately $272.5 million. Substantial decreases in oil and natural gas prices would render a significant number of our potential or planned projects uneconomic, particularly in the Cherokee Basin. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. We are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and may, therefore, require a writedown of such carrying value. We may incur additional impairment charges in the future, which could result in a material reduction in our results of operations in the period taken and materially limit our ability to borrow funds under our reserve-based credit facility and our ability to pay distributions to our unitholders.

Due to our lack of asset and geographic diversification, adverse developments in our core operating areas would affect our results of operations and reduce our ability to pay distributions to our unitholders.

We rely exclusively on sales of the oil and natural gas that we produce. Furthermore, all of our assets are located in Alabama, Kansas, Nebraska and Oklahoma and are predominantly coalbed methane natural gas. We currently have a limited amount of drilling opportunities in our existing asset base in the Cherokee Basin that enable us to focus on oil completions. Due to our lack of diversification in asset type, commodity type and location, an adverse development in the oil and gas business or these geographic areas would have a significantly greater impact on the price which we receive for our oil and natural gas, our results of operations, and any cash available for distributions to our unitholders than if we maintained more diverse assets and locations.

We depend on certain key customers for sales of our oil and natural gas. To the extent these and other customers reduce the volumes of oil or natural gas they purchase from us and are not replaced by new customers, our revenues and cash available for distribution could decline.

We currently sell our natural gas produced in the Black Warrior Basin to J.P. Morgan Ventures Energy Corporation and Southcross Alabama Gathering System, L.P. We currently sell our natural gas produced in the Cherokee Basin to Macquarie Energy LLC, Keystone Gas Corporation, Scissortail Energy, LLC, Cotton Valley Compression, L.L.C., Cherokee Basin Pipeline, LLC, and ONEOK Energy Services Company, L.P. Our oil production in the Cherokee Basin is primarily purchased by Sunoco Partners Marketing and Terminals, L.P and Coffeyville Resources Refining and Marketing, LLC. Our natural gas production in the Woodford Shale and our oil production the Central Kansas Uplift are marketed by the operators of the wells. To the extent these or other customers reduce the volumes of oil and natural gas that they purchase from us and are not replaced by new customers or the market prices for oil and natural gas decline in our market areas, our revenues and cash available for distribution could decline.

Seasonal weather conditions adversely affect our ability to conduct exploration and production activities.

Oil and natural gas operations in Alabama, Kansas, Nebraska and Oklahoma are often adversely affected by seasonal weather conditions, primarily during hurricane season, periods of severe weather or rainfall, and during periods of extreme cold. We face the risk that power outages and other damages resulting from hurricanes, tornados, ice storms, flooding, and other strong storms will prevent us from operating our wells in an optimal manner.

Certain of our undeveloped leasehold acreage is subject to leases that may expire in the near future and our concession agreement with the Osage Nation has certain terms and conditions which must be fulfilled by us.

Some of the leases that we hold are still within their original lease term and are not currently held by production. Unless we establish commercial production on the properties subject to these leases, these leases will expire. Our concession agreement with the Osage Nation also has certain terms and conditions which must be fulfilled by us. If our leases expire or our concession with the Osage Nation terminates, we will lose our right to develop the related properties, which would reduce our future cash flows and adversely affect our ability to pay distributions.

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Shortages of drilling rigs, supplies, oilfield services, equipment and crews could delay our operations and reduce our cash available for distribution.

Higher oil and natural gas prices generally increase the demand for drilling rigs, supplies, services, equipment and crews, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues and cash available for distribution.

Locations that we decide to drill may not yield oil and natural gas in commercially viable quantities.

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 uneconomical if we drill dry holes or wells that are productive but do not produce enough oil and natural gas 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, and could have a material adverse impact on our business.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate, select and finance the acquisition of suitable properties and our ability to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas, but also conduct refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, these companies may have a greater ability to continue drilling activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state and local laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business, financial condition, results of operations and ability to pay distributions.

Our acquisition activities will subject us to certain risks.

Any acquisition involves potential risks, including, among other things: the validity of our assumptions about reserves, future production, revenues and costs, including synergies; an inability to integrate successfully the businesses we acquire; a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions; a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions; the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate; the diversion of management s attention to other business concerns; an inability to hire, train or retain qualified personnel to manage and operate our business and assets; the incurrence of other significant charges, such as impairment of other intangible assets, asset devaluation or restructuring charges; unforeseen difficulties encountered in operating in new geographic areas; an increase in our costs or a decrease in our revenues associated with any potential royalty owner or landowner claims or disputes; and key customer or key employee losses at the acquired businesses.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

If any of our acquisitions do not generate increases in available cash per unit, our ability to pay distributions could materially decrease.

Risks Related to Regulatory Compliance, including Environmental Matters

Potential regulatory actions could increase our operating or capital costs and delay our operations or otherwise alter the way we conduct our business.

Exploration and development activities and the production and sale of oil and natural gas are subject to extensive federal, state, local and Native American tribal regulations. Changes to existing regulations or new regulations may unfavorably impact us, our suppliers or our customers. In the United States, legislation that directly impacts the oil and gas industry has been proposed covering areas such as emission reporting and reductions, hydraulic fracturing of wells, the repeal of certain oil and natural gas tax incentives and tax deductions, and the treatment and disposal of produced water. The EPA has also ruled that carbon dioxide, methane and other greenhouse gases endanger human health and the environment. This allows the EPA to adopt and implement regulations restricting greenhouse gases under existing provisions of the federal Clean Air Act. Additionally, provisions of the Dodd-Frank Act which regulate financial derivatives may impact our ability to enter into derivatives or require burdensome collateral or reporting requirements. These and other potential regulations could increase our costs, reduce our liquidity, impact our ability to hedge our future oil and natural gas sales, delay our operations or otherwise alter the way we conduct our business, negatively impacting our financial condition, results of operations and cash flows.

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

Our oil and natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities and Native American tribal authorities. For example, we have a concession agreement from the Osage Nation for a substantial portion of our leases in the Cherokee Basin. Failure or delay in obtaining regulatory approvals, leases, or drilling permits could have a material adverse effect on our ability to develop our properties, and receipt of drilling permits with onerous conditions could increase our compliance costs. In addition, regulations regarding conservation practices and the protection of correlative rights affect our operations by limiting the quantity of oil and natural gas we may produce and sell.

We are subject to federal, state, local, and Native American tribal laws and regulations as interpreted and enforced by governmental and Native American tribal authorities possessing jurisdiction over various aspects of the exploration, production and transportation of oil and natural gas. The possibility exists that these new laws, regulations or enforcement policies could be more stringent and significantly increase our compliance costs. If we are not able to recover the resulting costs from insurance or through increased revenues, our ability to pay distributions to our unitholders could be adversely affected. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating staff. Please read Item 1. Business-Operations-Environmental Matters and Regulation for more information on the laws and regulations that affect us.

Because we handle oil, natural gas, and other petroleum products in our business, we may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations.

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

- the federal Clean Air Act, related federal regulations and comparable state laws and regulations that impose obligations related to air emissions;
- the federal Clean Water Act, related federal regulations and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated waters;
- the federal RCRA, related federal regulations and comparable state laws and regulations that impose requirements for the handling and disposal of waste from our facilities;

- the federal CERCLA, also known as the Superfund law, related federal regulations and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal; and

- the federal Oil Pollution Act, related federal regulations and comparable state laws and regulations that impose obligations related to oil spill response and natural resource damage assessment.

Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover these costs from insurance or through increased revenues.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary fines or penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Certain environmental statutes, including RCRA, CERCLA, the federal Oil Pollution Act 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 into the environment.

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Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely affect our drilling and production operations.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over certain hydraulic fracturing practices. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with initial results of the study anticipated to be available by late 2012 and final results by 2014. Legislation has been introduced, but not adopted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. If new laws or regulations that significantly restrict or regulate hydraulic fracturing are adopted that apply to our operations, such legal requirements could make it more difficult or costly for us to perform fracturing activities. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that are ultimately able to be produced in commercial quantities from our properties.

We may incur significant costs and liabilities in the future resulting from an accidental release of hazardous substances into the environment.

There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. For example:

- there is the potential for an accidental release from one of our wells or gathering pipelines;

- certain of our operations are known to bring to the surface NORM that is accumulated at our facilities and is subject to permitting and controls for storage, as well as requirements for proper disposal; and

- several treatment ponds associated with the treatment and storage of produced waters and similar wastewaters have leaked into the subsurface in the past, and we have replaced certain of the liners beneath these treatment ponds in the Black Warrior Basin and, under the supervision of the ADEM, are monitoring for the presence of contaminants in the subsurface to better determine what cleanup, if any, may be required.

If a problem occurs with respect to any one of these, it 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.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas exploration, production and transportation operations. These costs and liabilities could arise under a wide range of federal, state, local, and tribal environmental and safety laws and regulations, including enforcement policies which have tended to become increasingly strict over time. There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances that we handle.

For instance, we must maintain permits and adhere to certain controls related to the storage and proper disposal of NORM that is produced periodically in connection with our natural gas drilling operations in the Black Warrior Basin. In addition, as a result of leaks from ponds used for the treatment and storage of produced waters and similar wastewaters from our operations in the past, we have replaced certain of the pond liners and are also conducting subsurface monitoring for chlorides under the supervision of ADEM. We may incur additional expenses, which could be material, in the future if our monitoring activities reveal that any contaminants exist in the subsurface beneath the ponds, and the agency requires cleanup of any such contaminants. Additionally, climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas while the physical effects of climate change, including severe weather events, could disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects.

Failure to comply with environmental laws and regulations could result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of orders to limit or cease certain operations. In addition, certain environmental laws impose strict or joint and several liability, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for damages as a result of environmental and other impacts.

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The coalbeds from which we produce natural gas frequently contain water that may hamper our ability to produce natural gas in commercial quantities or adversely affect our profitability.

Unlike conventional natural gas production, coalbeds frequently contain water that must be removed in order for the gas to desorb from the coal and flow to the wellbore. Our ability to remove and dispose of sufficient quantities of water from the coal seam will determine whether or not we can produce natural gas in commercial quantities. In addition, the cost of water disposal may be significant, may increase over time and may reduce our profitability.

We may face unanticipated water disposal costs.

Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies or our wells produce water in excess of the applicable volumetric permit limit, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot renew or obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- our wells produce excess water; or
- new laws and regulations require water to be disposed of or treated in a different manner.

ADEM is currently evaluating the formula used to determine the level of pollutants discharged into the waters of the state of Alabama and the resulting quality of water. Approval and issuance of our NPDES permit renewal applications by ADEM is pending completion of ADEM s evaluation and a final determination of the appropriate standard of measurement. Although we anticipate renewal of our NPDES permits, there is a risk that the standard for measuring pollutants and water quality in the state of Alabama could be changed to require more stringent discharge limitation and monitoring requirements.

Risks Related to Financing and Credit Environment

Our reserve-based credit facility has substantial restrictions and financial covenants and requires periodic borrowing base redeterminations.

We depend on our reserve-based credit facility for future capital needs. The reserve-based credit facility restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We are also required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, including events and circumstances that may stem from the condition of financial markets and commodity price levels. Our failure to comply with any of the restrictions and covenants under our reserve-based credit facility could result in an event of default, which could cause all of our existing indebtedness to become immediately due and payable. Each of the following is also an event of default:

- failure to pay any principal when due or any interest, fees or other amount prior to the expiration of certain grace periods;
- a representation or warranty made under the loan documents or in any report or other instrument furnished thereunder is incorrect when made;

failure to perform or otherwise comply with the covenants in the reserve-based credit facility or other loan documents, subject, in certain instances, to certain grace periods;

any event that permits or causes the acceleration of the indebtedness;

bankruptcy or insolvency events involving us or our subsidiaries;

certain changes in control as specified in the covenants to the reserve-based credit facility;

the entry of, and failure to pay, one or more adverse judgments in excess of $1.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and

specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $1.0 million in any year.

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Our reserve-based credit facility matures on November 13, 2013 and, as a result, amounts due under the facility are scheduled to become a current liability on November 13, 2012. We may not be able to renew or replace the facility at similar borrowing costs, terms, covenants, restrictions, or borrowing base, or with similar debt issue costs.

The reserve-based credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. Our borrowing base will be redetermined semi-annually, and may be redetermined at our request more frequently and by the lenders in their sole discretion based on reserve reports prepared by reserve engineers, using, among other things, the oil and natural gas prices existing at the time. The lenders can unilaterally adjust our borrowing base and the borrowings permitted to be outstanding under the reserve-based credit facility. Any increase in our borrowing base requires the consent of all the lenders. Outstanding borrowings in excess of our borrowing base must be repaid, or we must pledge other oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the reserve-based credit facility.

The reserve-based credit facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the facility and we would be in default under the facility, which could cause all of our existing indebtedness to become immediately due and payable.

Our reserve-based credit facility may restrict us from paying any distributions on our outstanding units.

We have the ability to pay distributions to unitholders under our reserve-based credit facility from available cash, including cash from borrowings under the reserve-based credit facility, as long as no event of default exists and provided that no distribution to unitholders may be made if the borrowings outstanding, net of available cash, under our reserve-based credit facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. At December 31, 2011, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions. Our ability to pay distributions to our unitholders in any quarter will be solely dependent on our ability to generate sufficient cash from our operations and is subject to the approval of our board of managers.

Economic conditions and instability in the financial markets could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions. The consequences of the current economic, political and credit environment include a lower level of economic activity and increased volatility in energy prices. A lower level of economic activity might result in a decline in energy consumption and lower market prices for oil and natural gas, which may adversely affect our financial results, our ability to fund maintenance capital expenditures and our ability to pay distributions.

Instability in the financial markets may affect the cost of capital and our ability to raise capital and may reduce the amount of cash available to fund our operations. We rely on our cash flow from operations and our reserve-based credit facility to fund our drilling programs, fund acquisitions, and meet our financial commitments and other short-term liquidity needs. Disruptions in the capital and credit markets as a result of uncertainty or the failure of significant financial institutions or other market participants could adversely affect our access to liquidity needed for our business. Any disruption could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include reducing our drilling programs, reducing capital expenditures, reducing our operations to lower expenses, reducing other discretionary uses of cash, and limiting our ability to pay distributions.

Disruptions in capital and credit markets may also result in higher LIBOR interest rates on our reserve-based credit facility, which may increase our interest expense and adversely affect our financial results. Additionally, lower market prices for oil and natural gas may result in a decrease in our borrowing base under our reserve-based credit facility at the time of a borrowing base redetermination. The lenders in our reserve-based credit facility may be unable to fund our borrowing requests, which would negatively impact our ability to operate our business.

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We will be required to make substantial investment or expansion capital expenditures to increase our asset base. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to pay distributions may be diminished or our financial leverage could increase.

In order to expand our asset base, we will need to make investment or expansion capital expenditures. If we do not make sufficient or effective expansion capital expenditures, we will be unable to expand our business operations, and may be unable to pay distributions. To fund our investment or expansion capital expenditures, we will be required to use cash from our operations or incur borrowings or sell additional common units or other securities. Such uses of cash from operations will reduce any cash available for distribution to our unitholders. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering and the covenants in our existing debt agreement, as well as by general economic conditions, world-wide credit and market conditions, and contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining the necessary funds, the terms of such financings could limit our ability to pay distributions to our unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional securities may result in significant unitholder dilution and an increase in the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate.

Furthermore, if our revenues or the borrowing base under our reserve-based credit facility decreases as a result of lower oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to increase or sustain our asset base. Our reserve-based credit facility restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our reserve-based credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a possible decline in our oil and natural gas reserves, and could have a material adverse impact on our business, financial condition, results of operations and ability to pay distributions.

We are exposed to credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our customers, counterparties, vendors and counterparties to our reserve-based credit facility and hedging arrangements. Some of our customers, counterparties and vendors may be highly leveraged and subject to their own operating and regulatory risks. Additionally, all but one of the counterparties in our reserve-based credit facility are large European financial institutions that may be negatively impacted by current economic events in Europe. Despite our credit review and analysis, we may experience financial losses in our dealings with these and other parties with which we enter into transactions as a normal part of our business activities. Any nonpayment or nonperformance by our customers, counterparties, vendors or lenders could have a material adverse impact on our business, financial condition, results of operations or ability to pay distributions.

Our future debt levels may limit our flexibility to obtain additional financing and pursue other business opportunities.

We may incur substantial additional indebtedness in the future under our reserve-based credit facility or otherwise. Our future indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, maintenance and investment capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- covenants and financial tests contained in our existing and future credit and debt instruments may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

- increased cash flow required to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and any distributions to unitholders; and

- our debt level may make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing any distributions, reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to affect any of these remedies on satisfactory terms or at all.

We may incur substantial additional debt in the future to enable us to pursue our business plan and to pay distributions to our unitholders.

Our business requires a significant amount of capital expenditures to maintain and grow production levels. Commodity prices have historically been volatile and we cannot predict the prices we will be able to realize for our production in the future. Declines in our production or declines in realized oil and natural gas prices for prolonged periods and resulting decreases in our borrowing base may result in the continuation of the suspension of our distribution.

If we were to borrow under our reserve-based credit facility to pay distributions, we would be distributing more cash than we are generating from our operations on a current basis. Any use of our borrowing capacity to fund distributions would limit the capital available to us to maintain or expand our operations. If we use borrowings under our reserve-based credit facility to pay distributions for an extended period of time rather than for the funding of maintenance capital expenditures and other purposes relating to our operations, we may be unable to support or grow our business. Any curtailment of our operations will limit our ability to make distributions on our units. If we were to borrow to pay distributions during periods of low commodity prices and commodity prices fail to recover, we may have to reduce or suspend our distributions in order to avoid excessive leverage.

Increases in inflation, or expectations of increases in inflation or stagflation, could increase our costs and adversely affect our business and operating results.

During periods of increased inflation or stagflation, our costs of doing business could increase, including increases in the variable interest rates we pay on amounts we borrow under our reserve-based credit facility. In addition, as we have hedged a large percentage of our future expected production volumes, the cash flow generated by that future hedged production will be capped. If any of our operating, administrative or capital costs were to increase as a result of inflation or any temporary or long-term increase in the cost of goods and services, such a cap could have a material adverse effect on our business, financial condition, results of operations, ability to pay distributions, and the market price of our common units.

An increase in interest rates may cause the market price of our common units to decline and may increase our borrowing costs.

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including equity investments such as publicly-traded limited liability company interests. Reduced demand for our common units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

Higher interests rates may also increase the borrowing costs associated with our reserve-based credit facility. If our borrowing costs were to increase, our interest payments on our debt may increase which would reduce the amount of cash available for distribution to unitholders.

Risks Related to Our Distribution to Unitholders

We may not have sufficient available cash from operations to resume our quarterly distributions to unitholders following the establishment of cash reserves and the payment of fees and expenses.

Since we announced a suspension of our distribution in June 2009, we have not had sufficient available cash, and may not have sufficient available cash in the future, to pay distributions to our unitholders following establishment of cash reserves by our board of managers for the proper conduct of our business and the payment of fees and expenses. The amount of available cash from which we may pay distributions is defined in both our reserve-based credit facility and our limited liability company agreement. The amount of available cash we distribute is subject to the definition of operating surplus in our limited liability company agreement and is impacted by the amount of cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. Ultimately, the amount of available cash that we may distribute to our unitholders principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on numerous factors generally described in this caption Risk Factors, including, among other things: the amount of oil and natural gas we produce; the demand for and the price at which we are able to sell our oil and natural gas production; the results of our hedging activity; the level of our operating costs; the costs we incur to acquire oil and natural gas properties; whether we are able to continue our development activities at economically attractive costs; further reduction of debt balances made by us; the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon; the amount of working capital required to operate our business; and the level of our maintenance capital expenditures.

In order for us to make a distribution from available cash under our reserve-based credit facility, our outstanding debt balances, net of available cash, must be less than 90% of the borrowing base, as determined by our lenders, after giving effect to the proposed distribution. Our available cash excludes any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. We are subject to additional future borrowing base redeterminations before our reserve-based credit facility matures in November 2013 and cannot forecast the level at which our lenders will set our future borrowing base. If our lenders further reduce our borrowing base because of any of the numerous factors generally described in this caption Risk Factors, our outstanding debt balances, net of available cash, may exceed 90% of the borrowing base, as determined by our lenders, and we may be unable to resume our quarterly distributions or may again have to suspend our quarterly distributions. If we do not achieve our expected operational results and we may not be able to resume, maintain or increase quarterly distributions, which may cause the market price of our common units to decline substantially.

The amount of available cash that we may distribute to our unitholders also depends on other factors, some of which are beyond our control, including: the borrowing base under our reserve-based credit facility as determined by our lenders; our ability to make working capital borrowings under our reserve-based credit facility; our debt service requirements and covenants and restrictions on distributions contained in our reserve-based credit facility; fluctuations in our working capital needs; the timing and collectability of receivables; prevailing economic conditions; the level of oil and natural gas prices; our ability to hedge future exposures to changes in oil and natural gas prices; the amount of our estimated maintenance capital expenditures; and the amount of cash reserves established by our board of managers for the proper conduct of our business, including the maintenance of our asset base and the payment of future distributions on our Class A and common units and any management incentive interests. As a result of these factors, we may not have sufficient available cash to resume, maintain or increase our quarterly distributions. The amount of available cash that we could distribute from our operating surplus in any quarter to our unitholders may fluctuate significantly from quarter to quarter and may be significantly less than any prior distributions hat we have previously made. If we do not have sufficient available cash or future cash flow from operations to resume, maintain or increase quarterly distributions, the market price of our common units may decline substantially.

The amount of cash that we have available for distribution to our unitholders depends primarily upon our cash flow and not our profitability.

The amount of cash that we have available for distribution depends primarily on our cash flow, including cash from reserves and working capital (which may include short-term borrowings), and not solely on our profitability, which is affected by non-cash items. As a result, we may be unable to pay distributions even when we record net income, and we may pay distributions during periods when we incur net losses.

Oil and natural gas prices are very volatile. If commodity prices decline significantly for a temporary or prolonged period, our cash from operations may decline and we may be unable to pay distributions.

Our revenue, profitability and cash flow depend upon the prices and demand for oil and natural gas and a drop in prices can significantly affect our financial results and impede our growth. Changes in oil and natural gas prices have a significant impact on the value of our reserves and on our cash flow. In particular, declines in commodity prices will reduce the value of our reserves, our cash flow, our ability to borrow money or raise capital and our ability to pay distributions. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, 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 and natural gas; the price and level of foreign imports of oil and natural gas; 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 West Africa, the Middle East and South America; the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; the impact of U.S. dollar exchange rates on oil and natural gas prices; technological advances affecting energy consumption; domestic and foreign governmental regulations and taxation; the impact of energy conservation efforts; the costs, proximity and capacity of oil and natural gas pipelines and other transportation facilities; the price and availability of alternative fuels; and the increase in the supply of natural gas due to the development of natural gas fields in the Barnett shale, Haynesville shale, Marcellus shale, and other shale plays.

In the past, the prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue. If we reinstate our distribution or raise our distribution level in response to increased cash flow during periods of relatively high commodity prices, we may not be able to sustain those distribution levels during periods of lower commodity price levels.

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Our operations require substantial capital expenditures, which will reduce our cash available for distribution.

We will need to make substantial capital expenditures to maintain our asset base over the long term. These maintenance capital expenditures may include capital expenditures associated with drilling and completion of additional wells to offset the production decline from our producing properties or additions to our inventory of unproved properties or our proved reserves to the extent such additions maintain our asset base. These expenditures could increase as a result of:

- changes in our reserves;
- changes in oil and natural gas prices;
- changes in labor and drilling costs;
- our ability to acquire, locate and produce reserves;
- changes in leasehold acquisition or concession costs; and
- government regulations relating to safety and the environment.

Our significant maintenance capital expenditures will reduce the amount of cash we have available for distribution to our unitholders. In addition, our actual maintenance capital expenditures will vary from quarter to quarter. If we fail to make sufficient maintenance capital expenditures, our future production levels will decline which will materially and adversely affect our future revenues and the amount of cash available for distribution to our unitholders.

Each quarter we are required to deduct estimated maintenance capital expenditures from operating surplus, which may result in less cash available for distribution to unitholders than if actual maintenance capital expenditures were deducted.

Our limited liability company agreement requires us to deduct estimated, rather than actual, maintenance capital expenditures from operating surplus. The amount of estimated maintenance capital expenditures deducted from operating surplus will be subject to review and change by our conflicts committee of our board of managers at least once a year. In years when our estimated maintenance capital expenditures are higher than actual maintenance capital expenditures, the amount of cash available for distribution to unitholders will be lower than if actual maintenance capital expenditures were deducted from operating surplus. If we underestimate the appropriate level of estimated maintenance capital expenditures, we may have less cash available for distribution in future periods when actual capital expenditures begin to exceed our previous estimates. Over time, if we do not set aside sufficient cash reserves or have available sufficient sources of financing and make sufficient expenditures to maintain our asset base, we will be unable to pay distributions.

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

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, our current practice is to hedge, subject to the terms of our reserve-based credit facility, a significant portion of our expected production volumes for up to five years. As a result, we will continue to have direct commodity price exposure on the unhedged portion of our production volumes. The extent of our commodity price exposure is related largely to the effectiveness and scope of our hedging activities. For example, the derivative instruments we utilize are generally based on posted market prices, which may differ significantly from the actual oil and natural gas prices we realize in our operations.

Our actual future production may be significantly higher or lower than we estimated at the time we entered into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, which may result in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our hedging activities are subject to the following risks:

- a counterparty may not perform its obligation under the applicable derivative instrument;

- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and

- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures.

If we do not make acquisitions on economically acceptable terms, our future growth and the ability to reinstate, maintain or increase our distributions may be limited.

Our ability to grow and to reinstate, maintain or increase distributions to unitholders is partially dependent on our ability to make acquisitions that result in an increase in available cash per unit. We may be unable to make such acquisitions if 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 of these cases, our future growth and ability to reinstate, maintain, or increase our distributions will be limited. Furthermore, even if we do make acquisitions that we believe will increase available cash per unit, these acquisitions may nevertheless result in a decrease in available cash per unit.

Risks Related to Our Structure and Our Major Unitholders

PostRock and its affiliates own an interest in us through their ownership of our Class A and common units and Constellation and its affiliates own an interest in us through their ownership of our Class C management incentive interests and Class D interests. PostRock may sell its interests in the future, which could reduce the market price of our outstanding common units.

PostRock indirectly owns approximately 24.9% of our outstanding common units and all of our outstanding Class A units as of February 29, 2012, or an aggregate 26.4% interest in us. Constellation indirectly owns all of our outstanding Class C management incentive interests and all of our Class D interests as of February 29, 2012. If PostRock was to sell some or a substantial portion of its interest in us, it could reduce the market price of our outstanding common units.

PostRock and Constellation s interests in us may be transferred to a third party without common unitholder consent.

PostRock and Constellation s affiliates may transfer their respective Class A units, common units, Class C management incentive interests and Class D interests to a third party in any type of transaction, including a merger or a sale of all or substantially all of their respective assets without the consent of our common unitholders. Furthermore, there is no restriction in our limited liability company agreement on the ability of PostRock or Constellation to cause a transfer to a third party of all or any portion of their equity interests in CEPM or CEPH, respectively.

Members of our board of managers, our executive officers, PostRock and its affiliates including CEPM, and Constellation and its affiliates including CEPH, may have conflicts of interest with us. Our limited liability company agreement limits the remedies available to our unitholders in the event they have a claim relating to conflicts of interest or the resolution of such a conflict of interest.

Two members of our board of managers are appointed by CEPM, the holder of our Class A units and an affiliate of PostRock. Conflicts of interest may arise between us and our unitholders and members of our board of managers or our executive officers, PostRock and its affiliates including CEPM, and Constellation and its affiliates including CEPH. These potential conflicts may relate to the divergent interests of these parties. Situations in which the interests of members of our board of managers, our executive officers, or PostRock and Constellation and their affiliates, including CEPM and CEPH, may differ from interests of owners of common units include, among others, the following situations:

- our limited liability company agreement gives our board of managers 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 board of managers will use its reasonable discretion to establish and maintain cash reserves sufficient to maintain our asset base;

neither our limited liability company agreement nor any other agreement requires PostRock, Constellation or any of their affiliates to pursue a business strategy that favors us. Directors and officers of PostRock, Constellation, CEPM and CEPH have a fiduciary duty while acting in their capacity as such a director or officer of such entity to make decisions in the best interests of such entities stockholders, which may be contrary to our best interests;

neither PostRock nor Constellation, nor any of their affiliates, has any obligation to provide us with any opportunities to acquire additional oil and natural gas properties;

in some instances our board of managers may cause us to borrow funds in order to permit us to pay distributions to our unitholders, even if the purpose or effect of the borrowing is to make management incentive distributions to CEPH;

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none of our executive officers or the members of our board of managers, PostRock and its affiliates, including CEPM, or Constellation and its affiliates, including CEPH, are prohibited from investing or engaging in other businesses or activities that compete with us; and

our board of managers is allowed to take into account the interests of parties other than us, such as PostRock and its affiliates, including CEPM, or Constellation and its affiliates, including CEPH, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders.

If in resolving conflicts of interest that exist or arise in the future our board of managers or officers, as the case may be, satisfy the applicable standards set forth in our limited liability company agreement for resolving conflicts of interest, a unitholder will not be able to assert that such resolution constituted a breach of fiduciary duty owed to us or to our unitholders by our board of managers and officers.

If the holders of our common units vote to eliminate the special voting rights of the holders of our Class A units, our Class A units will convert into common units on a one-for-one basis and the holder of our management incentive interests will have the option of converting the management incentive interests into common units at their fair market value, which may be dilutive to our common unitholders.

The holders of our Class A units have the right, voting as a separate class, to elect two of the five members of our board of managers, and any replacement of either of such members. This right can be eliminated upon a vote of the holders of not less than a 66 2/3 % of our outstanding common units. If such elimination is so approved and PostRock and its affiliates do not vote their common units in favor of such elimination, the Class A units will be converted into common units on a one-for-one basis, which may be dilutive to the common unitholders. Additionally, CEPH, the holder of our Class C management incentive interests, will have the right to convert its Class C management incentive interests into common units based on the then fair market value of such interests, which may be dilutive to our common unitholders.

Our limited liability company agreement prohibits a unitholder who acquires 15% or more of our common units without the approval of our board of managers from engaging in a business combination with us for three years. This provision is intended to discourage a change of control transaction that could disproportionately benefit an interested unitholder .

Our limited liability company agreement effectively adopts Section 203 of the Delaware General Corporation Law (Section 203). Section 203, as it applies to us, prohibits an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in a business combination with us for three years following the time such person becomes an interested unitholder without the approval of our board of managers. We believe PostRock is now an interested unitholder under Section 203. Section 203 broadly defines business combination to encompass a wide variety of transactions with or caused by an interested unitholder that may have the effect of conferring a disproportionate economic benefit upon the interested unitholder, and is generally defined to include:

mergers and consolidations;

asset sales, leases, exchanges or other dispositions (in one or a series of transactions) except proportionately as a unitholder of the company;

any transaction which results in the issuance of securities by the company to the interested unitholder;

any transaction which has the effect of increasing the proportionate ownership of the interested unitholder in the company; and

any receipt by the interested unitholder of the benefit of any loan, guarantee, pledge or other financial benefit provided by the company where the interested unitholder receives a benefit on other than a pro rata basis with other unitholders.

The term business combination does not include tender offers and market purchases by an interested unitholder, or the election of mangers to the board of managers or proxy contests by an interested unitholder.

In addition to limiting our ability to enter into transactions with PostRock or its affiliates, this provision of our limited liability company agreement could have an anti-takeover effect with respect to transactions not approved in advance by our board of managers, including discouraging takeover attempts that might result in a premium over the market price for our common units, which could negatively affect the price of our common units.

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Our limited liability agreement confers upon our Class A unitholder certain voting rights which may limit transactions which we may do.

Our limited liability company agreement contains provisions that confer upon our Class A unitholder, currently a subsidiary of PostRock, certain voting rights including:

- the right to elect two members to our board of managers, with such person only being able to be removed by the Class A unitholder, and the right to consent to any increase in the size of our board of managers;
- the right to block the sale of all or substantially all of the assets of the Company; and
- the right to block a dissolution or, except under certain circumstances, merger or conversion of the Company.

These provisions limit common unitholders ability to effect certain business transactions which the Class A unitholder opposes.

Our limited liability agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our limited liability agreement restricts the voting rights of common unitholders by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than CEPM (now a subsidiary of PostRock), CEPH (a subsidiary of Constellation), or their affiliates or transferees and persons who acquire such units with the prior approval of our board of managers, cannot vote on any matter. Our limited liability agreement also contains provisions limiting the ability of common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting common unitholders ability to influence the manner or direction of management.

Our limited liability company agreement provides for a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If, at any time, any person owns more than 80% of the common units then outstanding, such person has the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units then outstanding at a price not less than the then-current market price of the common units. As a result, unitholders may be required to sell their common units at an undesirable time or price and therefore may receive a lower or no return on their investment. Unitholders may also incur tax liability upon a sale of their common units.

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

We may issue an unlimited number of limited liability company interests of any type, including common units and units with rights to distributions or in liquidation that are senior in order of priority to common units, without the approval of our unitholders.

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

- the common unitholders proportionate ownership interest in us may decrease;
- the amount of cash distributed on each common unit may decrease;
- the relative voting strength of each previously outstanding common unit may be diminished;
- the market price of the common units may decline; and

- the ratio of taxable income to distributions may increase.

Our limited liability company agreement limits and modifies our managers and officers fiduciary duties.

Our limited liability company agreement contains provisions that modify and limit our managers and officers fiduciary duties to us and our unitholders. For example, our limited liability company agreement provides that:

- our managers and officers will not have any liability to us or our unitholders for decisions made in good faith, which is defined so as to require that they believed the decision was in our best interests; and
- our managers and officers will not be liable for monetary damages to us or our unitholders for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the managers or officers acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that such conduct was unlawful.

Because we are a limited liability company, unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 18-607 of the Delaware Revised Limited Liability Company Act, we may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that

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for a period of three years from the date of an impermissible distribution, members or unitholders who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited liability company for the distribution amount. A purchaser of common units who becomes a member or unitholder is liable for the obligations of the transferring member to make contributions to the limited liability company that are known to such purchaser of units at the time it became a member and for unknown obligations if the liabilities could be determined from our limited liability company agreement.

The market price of our common units could be volatile due to a number of factors, many of which are beyond our control.

The market price of our common units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

changes in securities analysts recommendations and their estimates of our financial performance;

the public s reaction to our press releases, announcements and our filings with the SEC;

fluctuations in broader securities market prices and volumes, particularly among securities of oil and natural gas companies and securities of publicly traded limited partnerships and limited liability companies;

the sale of our units by significant unitholders or other market liquidity issues;

changes in market valuations of similar companies;

departures of key personnel;

commencement of or involvement in litigation;

variations in our quarterly results of operations or those of other oil and natural gas companies;

variations in the amount of any quarterly distributions;

future interest rates and expectations of inflation;

future issuances and sales of our common units or other classes of securities issued by us;

the borrowing base of our reserve-based credit facility as determined by our lenders in their sole discretion;

changes in government regulations or laws impacting businesses or the oil and gas industry;

- changes in the general condition of global economies that impacts commodities and financial markets;
- changes in general conditions in the U.S. economy, financial markets or the oil and natural gas industry; and
- lack of or changes in any sponsor.

In recent years, the securities markets have experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our common units.

Tax Risks to Unitholders

Unitholders may be required to pay taxes on income from us, including their share of ordinary income and any capital gains on dispositions of properties by us, even if they do not receive any cash distributions from us.

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. Generally, should we generate taxable income for a particular tax year and not pay any cash distributions, our unitholders will be required to pay the actual tax liability that results from their share of such taxable income even though they received no cash distributions from us.

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. Our unitholders may be allocated substantial taxable income with respect to such sale.

During 2011, we did not pay any cash distributions on any Class B common unit or Class A unit. Since we generated taxable income for the 2011 tax year, our unitholders and any unitholders who purchased and sold common units during 2011, did not receive cash distributions from us sufficient to pay any actual tax liability that results from their share of such 2011 taxable income. Further, if we generate taxable income for the 2012 tax year, our unitholders may not receive sufficient cash distributions from us during 2012 in an amount sufficient to pay the actual tax liability that result from their share of such 2012 taxable income.

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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 profit.

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.

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

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

Despite the fact that we are a limited liability company (LLC) under Delaware law, it is possible in certain circumstances for us to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we are so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

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 income tax rates, currently at a maximum rate of 35%, and would likely pay state income tax at varying rates. Distributions to unitholders would generally be taxed as corporate distributions, and no income, gain, loss, deduction or credit would flow through to the 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 could result in a material reduction in the anticipated cash flow and after-tax return to our unitholders that could result in a substantial reduction in the value of our common 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. For example, at the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us.

We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

In addition, because of widespread state budget deficits, 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. If any state were to impose a tax upon us as an entity, the cash available for distribution to unitholders would be reduced. Our limited liability company agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the initial quarterly distribution amount and the Target Distribution amount (as defined in our limited liability company agreement) will be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704 of the Internal Revenue Code and changing the treatment of certain types of income earned from profits or carried interests. It is possible that these legislative efforts could result in changes to the existing U.S. tax laws that apply to publicly traded partnerships, including us. Any modification to the U.S. federal income tax laws and interpretations thereof could make it more difficult or impossible to (i) meet the exception, which we refer to as the qualifying income exception, for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, (ii) affect or cause us to change our business activities, (iii) affect the tax consideration of an investment in us, (iv) change the character or treatment of portions of our income or (v) adversely affect an investment in our common units.

Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

We will be considered to have terminated for tax purposes due to a sale or exchange of 50% or more of our interests within a twelve-month period.

We will be considered to have terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. A constructive termination results in the closing of our taxable year for all unitholders, which would result in us filing two tax returns for one fiscal year, the cost of which would be borne by our unitholders, and could result in a deferral of depreciation deductions allowable in computing our taxable income. We are not able to control or to predict if or when we may technically terminate for tax purposes in the future and may incur additional costs and expenses as a result of a termination. During December 2011, we terminated for tax purposes due to an increase in the trading of our units primarily as a result of the Constellation and PostRock transaction. This will result in us filing two tax returns for one calendar year and the costs associated with the technical termination will be borne by all our unitholders.

In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. When treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our common units, and the costs of any contest will reduce cash available for distribution.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter that affects us. The IRS may adopt 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 and a court may disagree with some or all of those positions. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

Tax-exempt entities and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

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

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

Because we cannot match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform with all aspects of existing U.S. Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of common units and could have a negative impact on the value of our common units or result in audits of and adjustments to our unitholders tax returns.

Tax gain or loss on the disposition of our common units could be more or less than expected because prior distributions in excess of allocations of income will decrease a unitholder s tax basis in his common units.

If a unitholder sells any of his common units, he will recognize gain or loss equal to the difference between the amount realized and the tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income allocated for a common unit, which decreased the tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the tax basis in that common unit, even if the price received is less than the original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to the unitholder. In addition, if the unitholder sells his units, he may incur a tax liability in excess of the amount of cash received from the sale.

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Unitholders may be subject to state and local taxes and return filing requirements.

We currently do business and own assets in Alabama, Kansas, Nebraska, and Oklahoma. We are registered to do business in Texas. Each of these states, except Texas, imposes an income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may do business or own assets in other states in the future.

Some of the states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a common unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular common unitholder s income tax liability to the state, generally does not relieve a nonresident common unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to common unitholders for purposes of determining the amounts distributed by us.

It is the responsibility of each unitholder to file all U.S. federal, foreign, state and local tax returns that may be required of such unitholder.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the holders of management incentive interests and the common unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders, including holders of our management incentive interests. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain common unitholders and the holders of our management incentive interests, which may be unfavorable to such common unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the holders of our management incentive interests and certain of our common unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our common unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

We prorate our items of income, gain, loss and deduction between transferors and transferees of common units each month based upon the ownership of the common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The IRS may challenge this treatment, which could change the allocation of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of common units each month based upon the ownership of the common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations, and accordingly, our counsel is unable to opine as to the validity of this method. 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 amount our unitholders.

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

Because a common unitholder whose common units are loaned to a short seller to cover a short sale of common units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and he 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 common units may not be reportable by the unitholder and any distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units; therefore, 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 common units.

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Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

Substantive changes to the existing U.S. 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 costs and percentage depletion and deductions for United States production activities. Other proposed changes may affect our ability to remain taxable as a partnership for federal income tax purposes. We are unable to predict whether any changes, or other proposals to such laws, ultimately will be enacted. Any such changes could negatively impact the value of an investment in our units.

The value of an investment in our units could be affected by potential U.S. 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 could increase. These rates are subject to change by new legislation at any time. Higher tax rates may result in a lower market price for our common units.

Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements as defined by the SEC that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about:

- the volatility of realized oil and natural gas prices;
- the conditions of the capital markets, inflation, interest rates, availability of a credit facility to support business requirements, liquidity, and general economic and political conditions;
- the discovery, estimation, development and replacement of oil and natural gas reserves;
- our business, financial, and operational strategy;
- our drilling locations;
- technology;
- our cash flow, liquidity and financial position;
- the ability to extend or refinance our reserve-based credit facility;
- the level of our borrowing base under our reserve-based credit facility;
- the resumption or amount of our cash distributions;

- our hedging program and our derivative positions;
- our production volumes;
- our lease operating expenses, general and administrative costs and finding and development costs;
- the availability of drilling and production equipment, labor and other services;
- our future operating results;
- our prospect development and property acquisitions;
- the marketing of oil and natural gas;
- competition in the oil and natural gas industry;
- the impact of the current global credit and economic environment;
- the impact of weather and the occurrence of natural disasters such as fires, floods, hurricanes, tornados, earthquakes, snow and ice storms and other catastrophic events and natural disasters;
- governmental regulation, including environmental regulation, and taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas producing countries;
- lack of support from a sponsor or a change in sponsor; and
- our strategic plans, objectives, expectations, forecasts, budgets, estimates and intentions for future operations.

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, could, should, expect, plan, project, intend, anticipate, estimate, predict, potential, pursue, target, continue, the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Annual Report on Form 10-K are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Annual Report on Form 10-K are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors listed in the Risk Factors section and elsewhere in this Annual Report on Form 10-K. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties is included in Item 1. Business, and is incorporated herein by reference.

Our obligations under our reserve-based credit facility are secured by mortgages on our oil and natural gas properties, as well as a pledge of all ownership interests in our material subsidiaries. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Sources of Debt and Equity Financing Reserve-Based Credit Facility , in this Annual Report on Form 10-K for additional information concerning our reserve-based credit facility.

Item 3. Legal Proceedings

Royalty Litigation

On October 28, 2011, Jerry and Betty Wattenbarger and Patricia Webb, individually and as class representatives on behalf of similarly situated persons, filed a Class Action petition in the District Court of Nowata County, Oklahoma against the Company, CEP Mid-Continent, LLC, a subsidiary of the Company, and Newfield Exploration Mid-Continent, Inc., alleging Plaintiffs own oil, gas and mineral interests in lands and wells located in Nowata County, Oklahoma, subject to oil and gas leases owned and operated by Defendants and that Defendants have underpaid royalties due and owing on the true value received or that should have been received by Defendants for production from Plaintiffs mineral interests. Plaintiffs have alleged, among other things, breach of implied covenant to market; breach of express and implied lease obligations; violation of statutory law; breach of duty of good faith and fair dealing and of the duty to act as a reasonably prudent operator; breach of fiduciary duty; constructive fraud and failure to disclose facts surrounding deductions made from royalty payments. Plaintiffs seek certification of a statewide class of plaintiffs, specify that the class claims against the Company and its subsidiary relate to the proper payment for production occurring on or after February 1, 2007, and currently limit damage claims against all Defendants to no more than $75,000 with respect to each Plaintiff and no more than $5 million in the aggregate for the Plaintiffs and the individual putative class members, in each case exclusive of interest and costs, but inclusive of any attorneys fees. On December 1, 2011, the case was removed by Defendants to the United States District Court for the Northern District of Oklahoma, and on December 28, 2011, Defendants filed their answer to Plaintiff s petition.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our common units are listed on the NYSE Amex under the symbol CEP. On February 28, 2012, there were 23,712,857 common units outstanding and approximately 4,460 unitholders. On February 28, 2012, the market price for our common units was $2.54 per unit, resulting in an aggregate market value of units held by non-affiliates of approximately $45.2 million. The following table presents the high and low closing price for our common units during the periods indicated.

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	Common Stock High	Common Stock Low
2011		
First Quarter	$ 3.20	$ 2.25
Second Quarter	$ 2.85	$ 2.13
Third Quarter	$ 3.59	$ 2.58
Fourth Quarter	$ 2.73	$ 1.85
2010		
First Quarter	$ 4.91	$ 3.35
Second Quarter	$ 3.86	$ 2.85
Third Quarter	$ 3.78	$ 2.75
Fourth Quarter	$ 3.15	$ 2.78

The following table shows the amount per unit, record date and payment date of the quarterly distributions we paid on each of our common units for each period presented.

	Quarterly Distributions Per unit	Record date	Payment date
2009[(a)]			
First Quarter	$ 0.1300	May 8, 2009	May 15, 2009

(a) Quarterly distributions on our common units were suspended for all of 2011, 2010 and the second, third and fourth quarters of 2009. Subject to the terms of our reserve-based credit facility, our limited liability company agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date. Available cash generally means, for any quarter ending prior to liquidation:

(a) the sum of:

(i) all cash and cash equivalents that we and our subsidiaries (or our proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly-owned) have on hand at the end of that quarter; and

(ii) all additional cash and cash equivalents that we and our subsidiaries (or our proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly-owned) have on hand on the date of determination of available cash for that quarter resulting from working capital borrowings made subsequent to the end of such quarter,

(b) less the amount of any cash reserves established by the board of managers (or our proportionate share of cash reserves in the case of subsidiaries that are not wholly-owned) to:

(i) provide for the proper conduct of the business of us and our subsidiaries (including reserves for future capital expenditures including drilling and acquisitions and for anticipated future credit needs) subsequent to such quarter,

(ii) comply with applicable law or any loan agreement, security agreement, mortgage, debt instrument or other agreement or obligation to which we or any of our subsidiaries are a party or by which we are bound or our assets are subject; or

(iii) provide funds for distributions (1) to our unitholders or (2) in respect of our Class D interests or Class C management incentive interests with respect to any one or more of the next four quarters;

provided, however, that the board of managers may not establish cash reserves pursuant to (iii) above if the effect of such reserves would be that we are unable to distribute the quarterly distribution on all common units and Class A units with respect to such quarter; and provided further, that disbursements made by us or any of our subsidiaries or cash reserves established, increased or reduced after the end of that quarter, but on or before the date of determination of available cash for that quarter, shall be deemed to have been made, established, increased or reduced, for purposes of determining available cash, within that quarter if the board of managers so determines.

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Private Placements

There were no private placement transactions in 2011, 2010 and 2009.

Common Unit Performance Graphs

The following graph compares the cumulative 5-year total return to unitholders on Constellation Energy Partners LLC s common units relative to the cumulative total returns of the Russell 2000 index, the Alerian MLP index, the Dow Jones US Exploration & Production index, and a customized peer group of six companies that includes: Breitburn Energy Partners L.P., EV Energy Partners, L.P., Legacy Reserves LP, Linn Energy, LLC, Pioneer Southwest Energy Partners L.P. and Vanguard Natural Resources, LLC. The graph assumes that the value of the investment in the company s common units, in each index, and in the peer group (including reinvestment of dividends) was $100 on 12/31/2006 and tracks it through 12/31/2011.

The unit price performance included in this graph is not necessarily indicative of future unit price performance.

Item 6. Selected Financial Data

Set forth below is our selected historical consolidated financial data for the periods indicated. All of this historical financial data has been derived from our audited financial statements.

You should read the following selected financial data in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and our financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K.

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The following table presents a non-GAAP financial measure, Adjusted EBITDA, which we use in our business. This measure is not calculated or presented in accordance with generally accepted accounting principles (GAAP). We explain this measure and reconcile it to net income, the most directly comparable financial measure calculated and presented in accordance with GAAP in Non-GAAP Financial Measure Adjusted EBITDA below.

	Constellation Energy Partners LLC				
	For the year ended December 31, 2011	For the year ended December 31, 2010	For the year ended December 31, 2009 (in 000 s)	For the year ended December 31, 2008	For the year ended December 31, 2007
Statement of Operations Data:					
Revenues:					
Natural gas sales	$ 133,769	$ 103,997	$ 118,580	$ 135,437	$ 80,761
Oil and liquids sales	10,870	4,695	4,546	6,426	1,964
Gain / (loss) from mark-to-market activities	(39,422)	42,081	19,410	21,376	(6,856)
Total revenues	105,217	150,773	142,536	163,239	75,869
Operating expenses:					
Lease operating expenses	27,949	30,798	33,535	36,257	17,141
Cost of sales	2,188	2,473	2,638	7,261	1,788
Production taxes	2,897	3,179	3,153	8,398	3,646
General and administrative	16,599	20,351	18,506	13,998	8,789
Exploration costs	131	760	855	414	320
Depreciation, depletion and amortization	22,139	85,263	71,173	52,281	23,190
Asset impairments	2,935	272,487	5,113	25,638	
Accretion expenses	907	822	406	411	312
(Gain) / loss on sale of assets	19	(18)		(301)	86
Total operating expenses	75,764	416,115	135,379	144,357	55,272
Other expenses/(income):					
Interest expense	8,886	12,721	11,967	12,167	6,930
Interest expense -(Gain)/loss from mark-to-market activities	1,232	(765)	4,338		
Interest income	(2)	(3)	(2)	(350)	(465)
Other (income) expense	(249)	(385)	(123)	(203)	(109)
Total other expenses (income)	9,867	11,568	16,180	11,614	6,356
Total expenses	85,631	427,683	151,559	155,971	61,628
Net income (loss)	$ 19,586	$ (276,910)	$ (9,023)	$ 7,268	$ 14,241
Earnings (loss) per unit					
Earnings (loss) per unit-Basic	$ 0.81	$ (11.36)	$ (0.40)	$ 0.32	$ 0.87
Earnings (loss) per unit-Diluted	$ 0.81	$ (11.36)	$ (0.40)	$ 0.32	$ 0.87
Distributions declared and paid per unit	$	$	$ 0.26	$ 2.25	$ 1.6986
Other Financial Information (unaudited):					
Adjusted EBITDA	$ 96,596	$ 54,125	$ 66,992	$ 75,285	$ 52,840

	Constellation Energy Partners LLC				
	For the year ended December 31, 2011	For the year ended December 31, 2010	For the year ended December 31, 2009 (in 000 s)	For the year ended December 31, 2008	For the year ended December 31, 2007
Balance Sheet Data:					
Cash and cash equivalents	$ 17,176	$ 7,892	$ 11,337	$ 6,255	$ 18,689
Other current assets	27,920	45,199	33,928	45,976	27,184
Oil and natural gas properties, net of accumulated depreciation, depletion and amortization	266,085	276,919	612,625	662,519	643,653

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	Constellation Energy Partners LLC				
	For the year ended December 31, 2011	For the year ended December 31, 2010	For the year ended December 31, 2009 (in 000 s)	For the year ended December 31, 2008	For the year ended December 31, 2007
Other assets	23,125	54,367	50,427	44,099	17,129
Total assets	$ 334,306	$ 384,377	$ 708,317	$ 758,849	$ 706,655
Current liabilities	$ 14,554	$ 14,533	$ 16,484	$ 19,506	$ 20,551
Debt	98,400	165,000	195,000	212,500	153,000
Other long-term liabilities	14,432	13,024	12,129	6,754	16,702
Class D interests		6,667	6,667	6,667	7,000
Members equity:					
Common members equity	201,483	174,233	449,670	463,295	505,178
Accumulated other comprehensive income	5,437	10,920	28,367	50,127	4,224
Total members equity	206,920	185,153	478,037	513,422	509,402
Total liabilities and members equity	$ 334,306	$ 384,377	$ 708,317	$ 758,849	$ 706,655
Cash Flow Data:					
Net cash provided by operating activities	$ 87,690	$ 40,829	$ 56,087	$ 75,632	$ 42,499
Net cash used in investing activities	(10,713)	(13,766)	(22,571)	(95,008)	(502,533)
Net cash provided by (used in) financing activities	(67,693)	(30,508)	(28,434)	6,942	471,238
Development of natural gas properties	(10,967)	(7,973)	(22,913)	(47,897)	(23,645)

Non-GAAP Financial Measure Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) adjusted by:

- depreciation, depletion and amortization;
- write-off of deferred financing fees;
- asset impairments;
- (gain) loss on sale of assets;
- accretion expense;
- exploration costs;
- (gain) loss from equity investment;

- unit based compensation programs;
- (gain) loss from mark to market activities;
- unrealized (gain)/loss on derivatives/hedge ineffectiveness; and
- interest (income) expense, net which includes:
  - interest expense
  - interest expense gain/(loss) mark-to-market activities
  - interest (income)

Adjusted EBITDA is a significant performance metric used by our management to indicate (prior to the establishment of any cash reserves by our board of managers) the distributions we would expect to pay to our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support a quarterly distribution or an increase in our quarterly distribution rates. Adjusted EBITDA is also used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts and others to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure.

Our Adjusted EBITDA should not be considered as a substitute for net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

We are unable to reconcile our forecast range of Adjusted EBITDA to GAAP net income or operating income because we do not predict the future impact of adjustments to net income (loss), such as (gains) losses from mark-to-market activities and equity investments or asset impairments due to the difficulty of doing so, and we are unable to address the probable significance of the unavailable reconciliation, in significant part due to ranges in our forecast impacted by changes in oil and natural gas prices and reserves which affect certain reconciliation items.

The following table presents a reconciliation of net income (loss) to Adjusted EBITDA, our most directly comparable GAAP performance measure, for each of the periods presented:

			Constellation Energy Partners LLC		
	For the year ended December 31, 2011	For the year ended December 31, 2010	For the year ended December 31, 2009 (In 000 s)	For the year ended December 31, 2008	For the year ended December 31, 2007
Reconciliation of Net Income (Loss) to Adjusted EBITDA:					
Net income (loss)	$ 19,586	$ (276,910)	$ (9,023)	$ 7,268	$ 14,241
Adjusted by:					
Interest expense/(income), net	10,116	11,953	16,303	11,817	6,465
Depreciation, depletion and amortization	22,139	85,263	71,173	52,281	23,190
Asset impairments	2,935	272,487	5,113	25,638	
Accretion expense	907	822	406	411	312
(Gain)/loss on sale of assets	19	(18)		(301)	86
Exploration costs	131	760	855	414	320
Unit-based compensation programs	1,341	1,849	1,308	322	145
(Gain)/loss on mark-to-market activities	39,422	(42,081)	(19,410)	(21,376)	6,856
Unrealized (gain)/loss on derivatives/hedge ineffectiveness			267	(1,189)	1,225
Adjusted EBITDA	$ 96,596	$ 54,125	$ 66,992	$ 75,285	$ 52,840

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

The following discussion and analysis should be read in conjunction with the Item 6. Selected Financial Data and the accompanying financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, forecasts, guidance, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our 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 and natural gas, production volumes, estimates of proved reserves, capital expenditures, operating costs, lack of a sponsor, *economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in Item 1A. Risk Factors and Forward-Looking Statements, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.*

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Overview

We are a limited liability company formed in 2005 to acquire oil and natural gas properties. Our oil and natural gas reserves are located in the Black Warrior Basin of Alabama, the Cherokee Basin of Kansas and Oklahoma, the Woodford Shale in Oklahoma, and the Central Kansas Uplift in Kansas and Nebraska. Our current primary business objective is to create long-term value and to generate stable cash flows allowing us to make quarterly distributions to our unitholders. We plan to achieve our objective by executing our business strategy, which is to:

- organically grow our business by increasing reserves and production through what we believe to be low-risk development drilling that focuses on capital efficient production growth and oil opportunities on our existing properties;
- reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient hedging programs; and
- make accretive, right-sized acquisitions of oil and natural gas properties characterized by a high percentage of proved developed oil and natural gas reserves with long-lived, stable production and low-risk drilling opportunities.

We completed our initial public offering on November 20, 2006, and our Class B common units are currently listed on the NYSE Amex under the symbol CEP.

Unless the context requires otherwise, any reference in this Annual Report on Form 10-K to Constellation Energy Partners, we, our, us, CEP, the Company means Constellation Energy Partners LLC and its subsidiaries. References in this Annual Report on Form 10-K to Constellation, CCG, CEPH, and CHI are to Constellation Energy Group, Inc., Constellation Energy Commodities Group, Inc., Constellation Energy Partners Holdings, LLC, and Constellation Holdings, Inc., respectively. References in this Annual Report on Form 10-K to PostRock and CEPM are to PostRock Energy Corporation and its subsidiary Constellation Energy Partners Management, LLC, respectively.

During 2011, our company s performance exceeded or achieved the metrics and goals outlined in our 2011 business plan. Some key highlights for 2011 were:

- We have reduced our outstanding debt by 55.3% from a high of $220.0 million in 2009 to $98.4 million.
- Our successful capital expenditure programs have expanded our oil production from 2010 to 2011 by 72.1%. Oil revenues accounted for 16.6% of our total unhedged revenue stream in 2011.
- We reduced our general and administrative expenses by 18.4% and our lease operating expenses by 9.3% from 2010 to 2011.
- The NPI no longer burdens our properties in the Robinson s Bend Field.

We anticipate that our 2012 capital expenditures will allow us to maintain our 2012 production at relatively the same level as in 2011. As we return capital spending to maintenance levels, our lower outstanding debt, combined with our operational performance, reductions in our operating expenses and the success of our capital expenditure program, may allow us to consider the reinstatement of a cash distribution to unitholders in 2012.

Significant Operational Factors

Realized Prices. Our average realized price for the twelve months ended December 31, 2011, including hedge settlements, was $10.57 per Mcfe and $4.53 per Mcfe excluding hedge settlements. After deducting the cost of sales associated with third party gathering, our average realized prices were $10.41 per Mcfe including hedge settlements and $4.37 per Mcfe excluding hedge settlements.

Production. Our production for the twelve months ended December 31, 2011, was approximately 13.7 Bcfe, or an average of 37,477 Mcfe per day compared with approximately 15.0 Bcfe, or an average of 41,197 Mcfe per day for the twelve months ended December 31, 2010. Our 2011 production is lower than the production for the same period in 2010 because our capital spending has been below the maintenance capital expenditures required to offset the natural production declines associated with our existing wells and severe weather in our operating areas during 2011, offset by the impact of our December 2010 acquisition of oil properties in the Central Kansas Uplift.

Capital Expenditures and Drilling Results. For the twelve months ended December 31, 2011, we spent approximately $11.3 million in cash capital expenditures, consisting of $11.0 million in development expenditures, and $0.6 million in leasing unproved properties, offset by the receipt of $0.3 million in post-closing adjustments for our December 2010 acquisition of oil properties in the Central Kansas Uplift. We have completed 35 net wells and 49 net recompletions and had 10 net wells and recompletions in progress at December 31, 2011.

Oil and Natural Gas Reserves. Our total year end 2011 proved reserves were 201.3 Bcfe which is 32.3 Bcfe higher than our year end 2010 proved reserves of 169.0 Bcfe. Our 2011 estimates of proved reserves were prepared in accordance with the SEC rules for oil and natural gas reserve reporting that require our proved reserves to be calculated using an average of the NYMEX spot prices for the sales of oil and natural gas on the first calendar day of each month of the year, adjusted for basis differentials. Our 2011 estimates of proved reserves increased from 2010 primarily due to increased oil reserves as a result of our successful drilling programs and reserve revisions as a result of lower operating expenses in the Cherokee Basin. We increased our oil reserves from 0.5 MBbl to 0.9 MBbl or by 86.7% by focusing our capital programs on drilling locations that have oil completions. Any of our locations that are scheduled to be drilled after 5 years are classified as probable or possible reserves if they are economic. Our reserves are 97% natural gas and are sensitive to lower SEC-required prices for natural gas and basis differentials in the Mid-Continent region. The 12-month average SEC-required price used to prepare our reserve report was $4.20 in the Black Warrior Basin and $3.88 in the Cherokee Basin. Although we utilize swaps and basis swaps to mitigate commodity price risk and basis differentials, these derivatives are not used when preparing our reserve report based on SEC rules. We do not use the SEC-required 12-month average price to make investment or drilling decisions. Instead, we use estimates of expected future observable market prices for oil and natural gas.

Reduction of Outstanding Debt. Through February 29, 2012, we reduced our outstanding debt from a high of $220.0 million in 2009 to $98.4 million or by 55.3%, which currently leaves us with $26.6 million of funds available for borrowing under our reserve-based credit facility. This reduction to below $100.0 million was a key goal of our 2011 business plan and was achieved by using our excess operating cash flows to lower our outstanding debt balance.

Hedging Activities. All of our derivatives are accounted for as mark-to-market activities. For the twelve months ended December 31, 2011, the unrealized non-cash mark-to-market loss was approximately $39.4 million as compared to an unrealized non-cash mark-to-market gain of $42.1 million for the same period in 2010.

During 2011 we executed a transaction to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production from January 2012 through December 2014. In conjunction with the transaction, we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million which was used to reduce our outstanding debt balance under our reserve-based credit facility.

We experience earnings volatility as a result of using the mark-to-market accounting method for our open derivative positions. This accounting treatment can cause extreme earnings volatility as the positions for future oil and natural gas production or interest rates are marked-to-market. These non-cash unrealized gains or losses are included in our current statement of operations until the derivatives are cash settled as the commodities are produced and sold or interest payments are made. Further detail of our open derivative positions and their accounting treatment is outlined below in Cash Flow From Operations-Open Commodity Hedge Positions, Critical Accounting Polices and Estimates-Hedging Activities, and Item 7A. Quantitative and Qualitative Disclosures about Market Risk-Interest Rate Risk.

Torch Royalty NPI Litigation Settlement and Class D Liquidation. During 2011, we entered into a final settlement agreement with the parties to the Torch Royalty Trust derivative litigation. The settlement agreement provided for a settlement of all claims in the lawsuit, a payment by us of $1.2 million to reimburse Trust Venture for its fees and expenses in prosecuting the lawsuit and an offer by us to purchase the NPI from the Trust for $1.0 million. We were the successful bidder in the public auction to acquire the NPI and the NPI was extinguished after it was assigned to us by the Trust. The NPI no longer burdens our properties in the Robinson s Bend Field. Further, since the NPI will no longer be paid based upon the sharing arrangement and we have suspended distributions since June 2009, there should be no further distributions required on our Class D interests as the capital account balance associated with the $6.7 million in unpaid Class D distributions was reduced to zero effective upon the close of the transaction. The Class D interests will remain outstanding, however, until the liquidation of CEP, but will be entitled to a zero liquidation amount.

Significant Market Factors

PostRock-Related Announcements. On August 8, 2011, PostRock announced that it had acquired all of our Class A units and 3,128,670 of our Class B common units in a transaction with Constellation. As a result of the transaction, PostRock received the right to appoint two Class A managers to our board of managers. On December 19, 2011, PostRock acquired Constellation s remaining 2,790,224 Class B common

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units. The units acquired in these two transactions in aggregate represent a 26.4% interest in us as of December 31, 2011. Approval of these transactions was neither required nor given by our board of managers or conflicts committee. We believe PostRock is now an interested unitholder under Section 203 of the Delaware General Corporation Law, which is incorporated by our limited liability company agreement. Section 203, as it applies to us, prohibits an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in business combinations with us for three years following the time such person becomes an interested unitholder without the approval of our board of managers and the vote of 66 2/3% of our outstanding Class B common units, excluding those held by the interested unitholder. Section 203 broadly defines business combination to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. In addition to limiting our ability to enter into transactions with PostRock or its affiliates, this provision of our limited liability company agreement could have an anti-takeover effect with respect to transactions not approved in advance by our board of managers, including discouraging takeover attempts that might result in a premium over the market price for our common units.

Results of Operations

The following table sets forth the selected financial and operating data for the periods indicated (in thousands except net production and average sales and costs):

	For the year ended December 31, 2011	For the year ended December 31, 2010	2011 Vs 2010 Variance $	%	For the year ended December 31, 2009	2010 Vs 2009 Variance $	%
Revenues:							
Natural gas sales	$ 129,059	$ 98,090	30,969	31.6%	$ 112,758	(14,668)	(13.0)%
Oil and liquids sales	10,870	4,695	6,175	131.5%	4,546	149	3.3%
Gain /(loss) from mark-to- market activities	(39,422)	42,081	(81,503)	(193.7)%	19,410	22,671	116.8%
Other	4,710	5,907	(1,197)	(20.3)%	5,822	85	1.5%
Total revenues	105,217	150,773	(45,556)	(30.2)%	142,536	8,237	5.8%
Operating expenses:							
Lease operating expenses	27,949	30,798	(2,849)	(9.3)%	33,535	(2,737)	(8.2)%
Cost of sales	2,188	2,473	(285)	(11.5)%	2,638	(165)	(6.3)%
Production taxes	2,897	3,179	(282)	(8.9)%	3,153	26	0.8%
General and administrative	16,599	20,351	(3,752)	(18.4)%	18,506	1,845	10.0%
Exploration costs	131	760	(629)	(82.8)%	855	(95)	(11.1)%
(Gain) /loss on sale of assets	19	(18)	37	(205.6)%		(18)	
Depreciation, depletion and amortization	22,139	85,263	(63,124)	(74.0)%	71,173	14,090	19.8%
Asset impairments	2,935	272,487	(269,552)	(98.9)%	5,113	267,374	5,229.3%
Accretion expenses	907	822	85	10.3%	406	416	102.5%
Total operating expenses	75,764	416,115	(340,351)	(81.8)%	135,379	280,736	207.4%
Other expenses (income):							
Interest expense	8,886	12,721	(3,835)	(30.1)%	11,967	754	6.3%
Interest expense (Gain)/loss from mark-to-market activities	1,232	(765)	1,997	(261.0)%	4,338	(5,103)	(117.6)%
Interest income	(2)	(3)	1	(33.3)%	(2)	(1)	50.0%
Other (income) expense	(249)	(385)	136	(35.3)%	(123)	(262)	213.0%
Total other expenses (income)	9,867	11,568	(1,701)	(14.7)%	16,180	(4,612)	(28.5)%

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	For the year ended December 31, 2011	For the year ended December 31, 2010	2011 Vs 2010 Variance $	%	For the year ended December 31, 2009	2010 Vs 2009 Variance $	%
Total expenses	85,631	427,683	(342,052)	(80.0)%	151,559	276,124	182.2%
Net income (loss)	$ 19,586	$ (276,910)	296,496	(107.1)%	$ (9,023)	$ (267,887)	2,968.9%
Net production:							
Natural gas production (MMcf)	13,047	14,670	(1,623)	(11.1)%	16,590	(1,920)	(11.6)%
Oil and liquids production (MBbl)	105	61	44	72.1%	78	(17)	(21.8)%
Total production (MMcfe)	13,679	15,037	(1,358)	(9.0)%	17,061	(2,024)	(11.9)%
Average daily production (Mcfe/d)	37,477	41,197	(3,720)	(9.0)%	46,742	(5,545)	(11.9)%
Average sales prices:							
Natural gas price per Mcf with hedge settlements[(a)]	$ 10.25	$ 7.09	$ 3.16	44.6%	$ 7.16	$ (0.07)	(0.98)%
Natural gas price per Mcf without hedge settlements	$ 3.96	$ 4.34	$ (0.38)	(8.8)%	$ 3.58	$ 0.76	21.2%
Oil and liquids price per Bbl with hedge settlements	$ 103.52	$ 76.97	$ 26.55	34.5%	$ 58.28	$ 18.69	32.1%
Oil and liquids price per Bbl without hedge settlements	$ 97.76	$ 76.97	$ 20.79	27.0%	$ 58.28	$ 18.69	32.1%
Total price per Mcfe with hedge settlements	$ 10.57	$ 7.23	$ 3.34	46.2%	$ 7.22	$ 0.01	0.1%
Total price per Mcfe without hedge settlements	$ 4.53	$ 4.54	$ (0.01)	(0.2)%	$ 3.75	$ 0.79	21.1%
Average unit costs per Mcfe:							
Field operating expenses[(b)]	$ 2.25	$ 2.26	$ (0.01)	(0.4)%	$ 2.15	$ 0.11	5.1%
Lease operating expenses	$ 2.04	$ 2.05	$ (0.01)	(0.5)%	$ 1.97	$ 0.08	4.1%
Production taxes	$ 0.21	$ 0.21	$ 0.00	0%	$ 0.18	$ 0.03	16.7%
General and administrative expenses	$ 1.21	$ 1.35	$ (0.14)	(10.4)%	$ 1.08	$ 0.27	25.0%
General and administrative expenses w/o unit-based compensation	$ 1.12	$ 1.23	$ (0.11)	(8.9)%	$ 1.01	$ 0.22	21.8%
Depreciation, depletion and amortization	$ 1.62	$ 5.67	$ (4.05)	(71.4)%	$ 4.17	$ 1.50	36.0%

(a) The average sales price for natural gas per Mcf with hedge settlements for 2011 includes the $41.3 million impact of our hedge restructuring.

(b) Field operating expenses include lease operating expenses (average production costs) and production taxes.

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

Oil and natural gas sales. Oil and natural gas sales increased $35.9 million, or 33.1%, to $144.6 million for the year ended December 31, 2011 as compared to $108.7 million for the same period in 2010. Of this increase, $42.3 million was attributable to higher hedge settlements for our oil and natural gas commodity derivatives, and $0.2 million was attributable to higher market prices for oil and lower market prices for natural gas, offset by $6.2 million attributable to lower natural gas production and increased oil production. Production for the twelve months ended December 31, 2011 was 13.7 Bcfe, which was 1.4 Bcfe or 9.0% lower than the same period in 2010. Of this decrease, 1.6 Bcfe was a reduction of natural gas production due to our reduced drilling programs in the Cherokee Basin, partially offset by increased oil production of 0.264

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Bcfe from our recently acquired properties in the Central Kansas Uplift and our drilling programs in the Cherokee Basin. Due to the decrease in the level of our drilling activities, our 2011 and 2010 maintenance drilling programs have not been sufficient to offset the natural decline rate of production associated with our existing wells. For 2012, we expect our maintenance capital expenditures to be $15.0 million. Our total capital expenditures for 2012 are expected to be between $15.0 million and $19.0 million, which is an amount of expenditures that could allow our 2012 production to remain relatively level with our 2011 production. We hedged approximately 73% of our actual production during 2011 and approximately 79% of our actual production during the same period in 2010.

Cash hedge settlements received for our oil and natural gas commodity derivatives were approximately $82.7 million for the year ended December 31, 2011. Cash hedge settlements received for our natural gas commodity derivatives were approximately $40.4 million for the year ended December 31, 2010. This increase of $42.3 million in 2011 is primarily due to our decision in the second quarter of 2011 to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production beginning in January 2012 through December 2014 where we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million, offset by the impact of lower market prices for natural gas and lower hedged volumes on our settlements during 2011.

As discussed below, the gain from our unrealized non-cash mark-to-market activities decreased $81.5 million for the year ended December 31, 2011, as compared to the same period in 2010. Our realized market prices before our hedging program decreased from 2010 to 2011 primarily due to lower market prices for natural gas, slightly offset by the impact of higher market prices for oil. The revenues that we generated from selling our products at realized market prices were offset by the impact of our hedging program and the associated mark-to-market gains and losses discussed below.

Mark-to-market activities. As of December 31, 2011, all of our hedges were accounted for as mark-to-market activities. For the year ended December 31, 2011, our unrealized non-cash mark-to-market loss was approximately $39.4 million as compared to an unrealized non-cash mark-to-market gain of approximately $42.1 million for the same period in 2010. This 2011 non-cash loss represents approximately $36.6 million from the impact of our decision to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production beginning in January 2012 through December 2014, offset by decreased future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities and by a $0.6 million decrease for non-performance risk related to our counterparties. This 2010 non-cash gain represented approximately $42.8 million from the impact of lower expected future natural gas prices on these derivative transactions that were being accounted for as mark-to-market activities and an approximately $1.4 million loss for non-performance risk related to our counterparties, offset by approximately $0.7 million in losses associated with 2011 natural production where we did not expect future volumes to exceed the hedged volumes that had been accounted for previously as cash flow hedges.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicle, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

For the year ended December 31, 2011, lease operating expenses decreased $2.9 million, or 9.3%, to $27.9 million, compared to expenses of $30.8 million for the same period in 2010. This $2.9 million decrease in lease operating expenses is related to our Cherokee Basin properties, while expenses for our Black Warrior and Woodford Shale properties remained flat. By category, our lease operating expenses were lower in 2011 as compared to 2010, because of decreases of $1.1 million in gas compression, $0.6 million in road and lease maintenance, $0.6 million in well servicing, workovers, and maintenance and repairs, $0.5 million in salt water disposal and $0.1 million in labor.

For the year ended December 31, 2011, our per unit lease operating expenses were $2.04 per Mcfe compared to $2.05 per Mcfe for the same period in 2010. Our decrease in per unit costs is attributable to a decrease in total spending of approximately 9.3% in 2011 as compared to the same period in 2010, offset by the impact of 1.4 Bcfe in lower production in 2011 as compared to the same period in 2010. Our per unit operating costs remained level in the Cherokee Basin from 2010 to 2011 at $2.33 per Mcfe. Our production decline is the result of reduced capital expenditures in 2011 and 2010. Additionally, during the first two quarters of 2011 we were temporarily impacted by lower production volumes and increased operating costs from weather-related maintenance and repairs. Further, on a per unit basis, the lease operating expenses associated with oil production is higher than that of natural gas production and our oil production increased by 72.1% from 2010 to 2011.

For the year ended December 31, 2011, production taxes decreased $0.3 million, or 8.9%, to $2.9 million, compared to production taxes of $3.2 million for the same period in 2010. This decrease was primarily the result of the impact of lower production taxes on 1.4 Bcfe in lower production and lower net market prices for oil and natural gas in 2011. We also recorded approximately $0.2 million more in Oklahoma production tax credits during 2011 as compared to 2010.

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Cost of sales. For the year ended December 31, 2011, cost of sales decreased by $0.3 million, or 11.5%, to $2.1 million, compared to $2.4 million for the same period in 2010. This represents the cost of purchased natural gas in the Cherokee Basin and was impacted by lower volumes of natural gas offset by decreased natural gas prices as these costs are tied to natural gas prices in the Mid-continent region.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, and other costs not directly associated with field operations.

General and administrative expenses decreased $3.7 million, or 18.4%, to $16.6 million for the year ended December 31, 2011, as compared to $20.3 million for the same period in 2010. Our general and administrative expenses were lower in 2011 as compared to 2010 because of $1.8 million in lower Torch-related legal costs, $0.8 million in lower labor, bonus, and benefits, $0.5 million in lower non-cash unit-based compensation expenses, $0.4 million in lower contractors and consulting fees, $0.2 million in lower audit and tax fees, $0.2 million in lower legal expenses, and $0.2 million in lower insurance costs, offset by $0.4 million in higher board of managers compensation.

Our per unit general and administrative costs were $1.21 per Mcfe for the year ended December 31, 2011 compared to $1.35 per Mcfe for the same period in 2010. This decrease is attributable to a decrease in total spending of $3.7 million offset by the impact of a 1.4 Bcfe decline in total production volumes. Our total general and administrative expenses paid in cash were approximately $3.2 million lower than in 2010.

Exploration costs. Exploration costs decreased $0.7 million, or 82.8%, to $0.1 million for the year ended December 31, 2011, as compared to $0.8 million for the same period in 2010. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment costs associated with leases on our unproved properties. The decrease in 2011 is primarily as the result of $0.8 million in lower lease abandonments in the Cherokee Basin and lower exploration costs in 2011 due to the impairment of certain unproved properties in the third quarter of 2010 because of lower expected future natural gas prices, offset by one dry hole costing $0.1 million in 2011.

Gain/loss on sale of assets. Our gain/loss on the sale of assets increased $0.04 million, or 205.6%, to a $0.02 million loss for the year ended December 31, 2011, as compared to a gain of $0.02 million for the same period in 2010. In 2011, we sold surplus equipment at a loss because our cash proceeds were slightly less than the net book value of the divested equipment.

Depreciation, depletion and amortization expense and Asset impairments. Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition and equipment costs, and asset impairment expense is incurred when the fair value of our assets is less than their historical net book value. Depletion is calculated using units-of-production. Assuming everything else remains unchanged, as natural gas production changes, depletion would change in the same direction.

Our depreciation, depletion and amortization expense for the year ended December 31, 2011 was $22.1 million, or $1.62 per Mcfe, compared to $85.3 million, or $5.67 per Mcfe, for the same period in 2010. This decrease of $63.2 million, or 74.0%, is primarily the result of lower depletion expense. This decrease in 2011 of depreciation, depletion, and amortization expense largely reflects the decreased basis in our assets resulting from our 2010 impairments of our oil and natural gas properties, as well as an increase in our year-end 2010 reserve base primarily due to price-related reserve revisions, higher capital expenditures for our development drilling programs, and a 1.4 Bcfe decrease in production volumes during 2011 as compared to 2010. We calculate depletion using units-of-production under the successful efforts method of accounting. Our other assets are depreciated using the straight line basis. Consistent with our prior practice, we use our 2011 reserve report to calculate our depletion rate during the first three quarters of 2012. We will use our 2012 reserve report to record our depletion in the fourth quarter of 2012. We estimate our depletion rate to be approximately $1.34 per Mcfe for the first three quarters of 2012.

Our asset impairments for the year ended December 31, 2011 were $2.9 million, compared to $272.5 million for the same period in 2010. Our non-cash impairment charges in 2011 were approximately $1.6 million to impair the value of our oil and natural gas properties in the Central Kansas Uplift, $1.0 million related to the extinguishment of the NPI and $0.3 million to impair certain of our wells in the Woodford Shale. These 2011 impairments were primarily caused by the impact of lower future oil and natural gas prices along with certain performance-related reserve revisions. Our non-cash impairment charges in 2010 were approximately $263.4 million to impair the value of our oil and natural gas properties in the Cherokee Basin, $6.3 million to impair the value of our other non-current intangible assets related to our activities in the Cherokee Basin, $0.4 million to impair the value of inventory in the Cherokee Basin, $1.9 million to impair the value of certain of our wells in the Woodford Shale and $0.5 million to impair the value of our casing inventory.

Interest expense. Interest expense for the year ended December 31, 2011 decreased $1.8 million, or 15.4%, to approximately $10.1 million as compared to approximately $12.0 million in interest expense for the same period in 2010. This decrease was primarily due to $2.0 million in higher non-cash mark-to-market losses on our interest rate swaps that are accounted for as mark-to-market activities, offset by lower interest rate swap settlements of $1.7 million and lower market interest rates resulting in lower interest expense of $2.1 million during 2011 as compared to the same period in 2010. At December 31, 2011, we had an outstanding balance under our reserve-based credit facility of $98.4 million as compared to $165.0 million at December 31, 2010. Since the third quarter of 2009, we have used our excess operating cash flow to reduce our total debt from a high of $220.0 million in 2009 to $98.4 million as of December 31, 2011. The average interest rate on our outstanding debt was approximately 5.7% in 2011 compared to 4.8% in 2010.

Interest income. Interest income for the year ended December 31, 2011 remained essentially level to the same period in 2010. During 2011, market rates for overnight investments continued to be at historical lows, resulting in no significant earnings on our cash balances. Our cash balance increased from $7.9 million at December 31, 2010, to $17.2 million at December 31, 2011.

Accumulated other comprehensive income. Accumulated other comprehensive income, shown on our consolidated balance sheets, reflected the fair market value of certain of our previously designated cash-flow hedge positions. At December 31, 2011, the balance was an unrealized gain of $5.4 million compared to an unrealized gain of $10.9 million at December 31, 2010. This decrease reflects the amortization to earnings for the derivative positions that were previously accounted for as cash flow hedges that have cash settled during 2011.

The decrease in accumulated other comprehensive income (loss) is shown in our consolidated statements of operations and comprehensive income (loss) as an unrealized loss of $5.5 million for the year ended December 31, 2011, and as an unrealized loss of $17.4 million for the same period in 2010. This decrease reflects the settlements during 2011 related to amounts previously included in locked accumulated other comprehensive income associated with our hedging positions previously accounted for as cash flow hedges. All of our derivative positions are now accounted for as mark-to-market activities and the remaining balance of $5.4 million in accumulated other comprehensive income (loss) at December 31, 2011, will be amortized to earnings as the positions settle in 2012.

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

Oil and natural gas sales. Oil and natural gas sales decreased $14.4 million, or 11.7%, to $108.7 million for the year ended December 31, 2010 as compared to $123.1 million for the same period in 2009. Of this decrease, $7.6 million was attributable to decreased production volumes and $12.0 million was attributable to higher market prices for oil and natural gas, offset by an $18.8 million decrease attributable to our hedge program. Production for the year ended December 31, 2010 was 15.0 Bcfe, which was 2.0 Bcfe, or 11.9%, lower than the same period in 2009. Our production was 1.6 Bcfe lower in the Cherokee Basin, 0.2 Bcfe lower in the Black Warrior Basin and 0.2 Bcfe lower in the Woodford Shale. The decline in the Cherokee Basin was due to capital spending in 2010 that was below the maintenance capital expenditures required to offset the natural decline production rate from our existing wells. The decline in the Black Warrior Basin was due to no drilling activities in 2010 and our recompletion program not offsetting the natural decline rate associated with our existing wells in the basin. This decline would have been higher had we not conducted a workover program in the Black Warrior Basin in early 2010. Our production in the Woodford Shale also declined 0.2 Bcfe during 2010. This was a result of natural declines in the field and the operators drilling additional wells in which we do not participate surrounding our 83 well bores. We hedged approximately 79% of our actual production during 2010 and approximately 81% of our actual production during 2009.

Cash hedge settlements received and hedge premium amortizations paid for our commodity derivatives were approximately $40.4 million for the year ended December 31, 2010. Cash hedge settlements paid for our commodity derivatives were $59.5 million for the year ended December 31, 2009. This difference is primarily due to a lower amount of natural gas volumes hedged during 2010 as compared to 2009 and higher market prices for natural gas in 2010.

As discussed below, the gain from our unrealized non-cash mark-to-market activities increased $22.7 million for the year ended December 31, 2010, as compared to the same period in 2009. Our realized prices before our hedging program increased from $3.75 per Mcfe in 2009 to $4.54 per Mcfe in 2010 primarily due to higher market prices for oil and natural gas as a result of an improvement in economic conditions increasing the demand for energy.

Mark-to-market activities. As of December 31, 2010, all of our hedges were accounted for as mark-to-market activities. For the year ended December 31, 2010, the unrealized non-cash mark-to-market gain was approximately $42.1 million as compared to an unrealized non-cash $19.4 million mark-to-market gain for the same period in 2009. This 2010 non-cash gain represents approximately $42.8 million from the impact of lower expected future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities and approximately $1.4 million loss for non-performance risk related to our counterparties, offset by approximately $0.7 million in losses associated with 2011 natural production where we did not expect future volumes to exceed the hedged volumes that had been accounted for previously as cash flow hedges.

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For the year ended December 31, 2009, we recognized a loss of approximately $0.3 million related to hedge ineffectiveness primarily related to our hedges of production in the Cherokee Basin that we used to account for as cash flow hedges. We did not experience any hedge ineffectiveness for 2010, as all our hedges are now accounted for as mark-to-market activities.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicle, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

For the year ended December 31, 2010, lease operating expenses decreased $2.7 million, or 8.2%, to $30.8 million, compared to expenses of $33.5 million for the same period in 2009. Of the $2.7 million decrease in lease operating expenses, $2.1 million is related to our Cherokee Basin properties, $0.5 million is related to our Woodford Shale well bores and $0.1 million is related to our Black Warrior properties. By category, our lease operating expenses were lower in 2010 as compared to 2009, because of decreases of $1.4 million in gas compression, $0.5 million in facilities costs, $0.4 million in power and fuel and $0.4 million in well servicing costs.

For the year ended December 31, 2010, per unit lease operating expenses were $2.05 per Mcfe compared to $1.97 per Mcfe for the same period in 2009. Our increase in per unit costs is attributable to a decrease in total spending of approximately 8.2% in 2010 as compared to the same period in 2009, offset by the impact of 2.0 Bcfe in lower production in 2010 as compared to the same period in 2009. Our per unit operating costs increased in the Cherokee Basin from $2.18 per Mcfe in 2009 to $2.33 per Mcfe in 2010 as a result of 1.6 Bcfe in lower production volumes and lower total spending that did not decrease proportionally with the decrease in production volumes. Our per unit operating costs increased in the Black Warrior Basin from $1.47 per Mcfe in 2009 to $1.51 per Mcfe in 2010 as a result of 0.2 Bcfe in lower production volumes not offsetting the impact of lower total spending. Our production declines are the result of capital spending in 2010 and 2009 that was below our maintenance capital expenditures in each year.

For the year ended December 31, 2010, production taxes were essentially level when compared to production taxes for the same period in 2009 due to higher realized prices on lower production volumes.

Cost of sales. For the year ended December 31, 2010, cost of sales decreased by $0.2 million, or 6.3%, to $2.4 million, compared to $2.6 million for the same period in 2009. This represents the cost of purchased natural gas in the Cherokee Basin and was impacted by lower volumes of natural gas offset by increased natural gas prices as these costs are tied to natural gas prices in the Mid-continent region.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, and other costs not directly associated with field operations.

General and administrative expenses increased $1.8 million, or 9.7%, to $20.3 million for the year ended December 31, 2010, as compared to $18.5 million for the same period in 2009. Our general and administrative expenses were higher in 2010 as compared to 2009 because of $1.3 million in higher labor, bonus, and benefits cost, $1.1 million in higher legal costs primarily associated with the Torch-related litigation, $0.4 million in higher non-cash unit-based compensation, $0.3 million in increased rent expense and $0.1 million in higher non-cash bad debt expense, offset by $1.4 million in lower charges from CEPM as our management services agreement with it was terminated on December 15, 2009.

Our per unit costs were $1.35 per Mcfe for the year ended December 31, 2010 compared to $1.08 per Mcfe for the same period in 2009. This increase is attributable to an increase in total spending of $1.8 million offset by the impact of a 2.0 Bcfe decline in total production volumes. During 2010, total spending increased as services were transitioned from being provided by CEPM under the management services agreement to us.

Exploration costs. Exploration costs decreased $0.1 million, or 11.1%, to $0.8 million for the year ended December 31, 2010, as compared to $0.9 million for the same period in 2009. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on our unproved properties. The decrease in 2010 is primarily a result of lower exploration costs in the fourth quarter of 2010 due to lower impairment, amortization, and abandonment associated with our leases on our unproved properties because the unproved value was impaired in the third quarter of 2010 due to lower expected future natural gas prices.

Gain/loss on sale of assets. Our gain/loss on the sale of assets remained essentially level for the year ended December 31, 2010, as compared to the same period in 2009. This amount represents the difference in the historical book cost of the assets sold and the cash proceeds from the sale. In both 2010 and 2009, we realized approximately $0.1 million in cash proceeds from asset sales.

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Depreciation, depletion and amortization expense and Asset impairments. Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition and equipment costs, and asset impairment expense is incurred when the fair value of our assets is less than their historical net book value. Depletion is calculated using units-of-production. Assuming everything else remains unchanged, as natural gas production changes, depletion would change in the same direction.

Our depreciation, depletion and amortization expense for the year ended December 31, 2010 was $85.3 million, or $5.67 per Mcfe, compared to $71.2 million, or $4.17 per Mcfe, for the same period in 2009. This increase of $14.1 million, or 19.8%, is primarily the result of higher depletion expense. The increase in 2010 depreciation, depletion, and amortization expense reflects the impact of a lower year-end 2009 reserve base primarily due to price-related reserve revisions, capital expenditures for our development drilling programs, and a 2.0 Bcfe decrease in production volumes during 2010 as compared to 2009. We calculate depletion using units-of-production under the successful efforts method of accounting. Our other assets are depreciated using the straight line basis. Consistent with our prior practice, we used our 2009 reserve report to calculate our depletion rate during the first three quarters of 2010 and we used our 2010 reserve report to record our depletion in the fourth quarter of 2010.

Our asset impairments for the year ended December 31, 2010 were $272.5 million, compared to $5.1 million for the same period in 2009. Our non-cash impairment charges were approximately $263.4 million to impair the value of our oil and natural gas properties in the Cherokee Basin, $6.3 million to impair the value of our other non-current intangible assets related to our activities in the Cherokee Basin, $0.4 million to impair the value of inventory in the Cherokee Basin, $1.9 million to impair the value of certain of our wells in the Woodford Shale and $0.5 million to impair the value of our casing inventory. Our 2009 impairment charges were related to $4.8 million for certain of our well bores in the Woodford Shale due to the impact of lower natural gas prices on expected estimated future cash flows associated with our well bores and a $0.3 million impairment of obsolete inventory and other miscellaneous straight-line assets.

Interest expense. Interest expense for the year ended December 31, 2010 decreased $4.3 million, or 26.4%, to $12.0 million as compared to approximately $16.3 million in interest expense for the same period in 2009. This decrease was primarily due to $5.1 million in lower non-cash mark-to-market losses on our interest rate swaps that are accounted for as mark-to-market activities because of higher market interest rates, lower interest rate swap settlements of $0.9 million due to higher market interest rates, higher actual interest expense due to increased market interest rates of $1.4 million offset by lower principal amounts outstanding, and lower capitalized interest of $0.3 million during 2010 as compared to the same period in 2009. During 2009 and 2010, we used our excess operating cash flow to reduce our total debt from a high of $220.0 million to $165.0 million which decreased the amount of cash interest payments on the lower outstanding balance. At December 31, 2010, we had an outstanding balance under our reserve-based credit facility of $165.0 million as compared to $195.0 million at December 31, 2009. The average interest rate on our outstanding debt was approximately 4.8% in 2010 compared to 6.4% in 2009. Our capitalized interest decreased from 2009 to 2010 due to lower capital spending in 2010.

Interest income. Interest income for the year ended December 31, 2010 remained essentially level to the same period in 2009. During 2010, market rates for overnight investments continued to be at historical lows, resulting in no significant earnings on our cash balances. In 2009, we discontinued our overnight investments to participate in a program sponsored by the FDIC s Transaction Account Guarantee Program to provide unlimited insurance coverage for transaction account balances that do not earn interest. This program was available until December 31, 2009.

Accumulated other comprehensive income. Accumulated other comprehensive income, shown on our consolidated balance sheets, reflects the changes in the fair market value of our previously designated cash-flow hedge positions. At December 31, 2010, the balance was an unrealized gain of $10.9 million compared to an unrealized gain of $28.4 million at December 31, 2009. This decrease reflects the settlements during 2010 related to amounts previously included in accumulated other comprehensive income associated with our hedging positions previously accounted for as cash flow hedges and $0.7 million in released deferred gains associated with 2011 natural gas production where we do not expect future volumes to exceed the hedged volumes that had been accounted for previously as cash flow hedges. All of our derivative positions are now accounted for as mark-to-market activities and the remaining balance in accumulated other comprehensive income will be amortized to earnings as the positions settle in the future.

The decrease in accumulated other comprehensive income (loss) is shown in our consolidated statements of operations and comprehensive income (loss) as an unrealized loss of $17.4 million for the year ended December 31, 2010, and as an unrealized loss of $21.8 million for the same period in 2009. This decrease reflects the difference in the hedge settlements during 2010 and 2009, which are related to amounts previously included in locked accumulated other comprehensive income associated with our hedging positions previously accounted for as cash flow hedges and $0.7 million in released deferred gains associated with 2011 natural production where we do not expect future volumes to exceed the hedged volumes that had been accounted for previously as cash flow hedges. All of our derivative positions are now accounted for as mark-to-market activities and the remaining balance in accumulated other comprehensive income (loss) will be amortized to earnings as the positions settle in the future.

Liquidity and Capital Resources

During 2011, we utilized our cash flow from operations as our primary source of capital. Our primary use of capital during this time was for the reduction of outstanding debt and the development of existing oil and natural gas properties within our asset base.

The primary focus of our business plan in 2011 has been to use our excess operating cash flows to reduce our outstanding debt level to below $100.0 million. Since we shifted our strategic focus to debt reduction, we have successfully reduced our outstanding debt balance from a high of $220.0 million in 2009 to $98.4 million as of February 29, 2012. Given our focus on debt reduction, our quarterly distributions to our unitholders remained suspended through the fourth quarter of 2011. The suspension of our quarterly distribution and keeping our capital expenditures below maintenance levels in 2010 and 2011 has provided additional liquidity to fund our operations, improve our cash position, and reduce our debt below $100.0 million. As of December 31, 2011, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business and the payment of fees and expenses) from which to pay distributions.

Based upon our current business plan for 2012, we anticipate that we will continue to generate sufficient operating cash flows to meet our working capital needs and fund a planned capital expenditure program that could maintain our total production relatively level with our production in 2011. Further, our business plan may allow us to consider the reinstatement of a quarterly distribution to our unitholders in 2012. Any future quarterly distributions must be approved by our board of managers. We will be monitoring the capital resources available to us to meet our future financial obligations and our planned 2012 capital expenditures. Our current expectation is that we will manage our business to operate within the cash flows that are generated. We expect that our 2012 capital expenditures will range between approximately $15.0 million and $19.0 million. Our future success in growing reserves and production will be highly dependent on the capital resources available to us and our success in drilling for or acquiring additional reserves and managing the costs associated with our operations. We routinely monitor and adjust our capital expenditures and operating expenses in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, availability of funds under our reserve-based credit facility, and internally generated cash flow. Based upon current oil and natural gas price expectations, our existing hedge positions and expected production levels in 2012, we anticipate that our cash flow from operations can meet any planned capital expenditures and other cash requirements for the next twelve months without increasing our debt or issuing additional equity securities, though we may raise additional capital if conditions warrant an acceleration of growth opportunities. Future cash flows and our borrowing capacity are subject to a number of variables, including the level of oil and natural gas production, the market prices for those products and our hedge positions. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain our reduced debt level, planned levels of capital expenditures, operating expenses, or any cash distributions that we may make to unitholders.

During the first quarter of 2012, the market price for natural gas has declined to the lowest level in ten years due to a record level of natural gas in storage, significant supply growth, and a warmer than normal winter, while oil prices have remained at historically high levels due to strong world-wide demand for crude oil products. We have a significant amount of our natural gas production hedged for 2012 through 2014 and our oil production hedged from 2012 through 2015. Our results will not be fully impacted by significant increases or decreases in oil and natural gas prices because of our hedging program. For 2012, we forecast total net production of between 13.3 Bcfe and 14.1 Bcfe. We have hedged approximately 69% of the midpoint of this forecast, including hedges for 2012 on 6.9 Bcfe of our Mid-Continent natural gas production at an average price, including basis, of $5.22 per Mcfe, 2.0 Bcfe of our remaining natural gas production at an average price of $5.75 per Mcfe, and 83 MBbl of our oil production at an average price of $103.14 per barrel. This hedge position locks in a significant portion of our expected operating cash flows for 2012, although we are still exposed to increases or decreases in oil and natural gas prices on our unhedged volumes. In the event of inflation increasing drilling and service costs, our hedging program will also limit our ability to have increased revenues recoup the higher costs, which could further impact our planned capital spending or operating expense levels.

Sources of Debt and Equity Financing

Our reserve-based credit facility currently provides a limited availability to finance future maintenance capital expenditures and other working capital needs. During 2011, we did not borrow any additional daily, short-term or long-term amounts under our reserve-based credit facility. As of February 29, 2012, the borrowing base under our reserve-based credit facility was $125.0 million and we had $98.4 million of debt outstanding under the facility, leaving us with $26.6 million in unused borrowing capacity. Our current reserve-based credit facility is subject to future borrowing base redeterminations and will have to be renewed or replaced before its maturity in November 2013. Our reserve-based credit facility is discussed below in further detail.

In the first quarter of 2011, we filed a new shelf registration statement with the SEC to register up to $500 million of debt or equity securities to repay or refinance outstanding debt and to fund working capital, capital expenditures and any acquisitions. This registration statement will expire in two years. As a smaller reporting company, any sales of securities under our shelf registration statement during the preceding rolling 12 months is limited to one-third of our public float. Our public float is calculated by multiplying the highest closing price of our Class B common units within the last 60 days by the number of outstanding Class B common units held by non-affiliates, currently including PostRock. There is no guarantee that securities can or will be issued under the registration statement or that conditions in the financial markets would be supportive of an issuance of such securities by us.

Reserve-Based Credit Facility

On June 3, 2011, we executed a second amendment to our $350.0 million reserve-based credit facility with The Royal Bank of Scotland plc as administrative agent and a syndicate of lenders extending its maturity date to November 13, 2013. Borrowings under the reserve-based credit facility are secured by various mortgages of oil and natural gas properties that we and certain of our subsidiaries own as well as various security and pledge agreements among us and certain of our subsidiaries and the administrative agent. The current lenders and their percentage commitments in the reserve-based credit facility are The Royal Bank of Scotland plc (26.84%), BNP Paribas (21.95%), The Bank of Nova Scotia (21.95%), Societe Generale (14.63%), and ING Capital LLC (14.63%). On February 21, 2012, Wells Fargo & Company announced it had agreed to purchase BNP Paribas energy lending business in the United States and that the purchase is subject to regulatory and other approvals and is expected to close in the second quarter of 2012.

The amount available for borrowing at any one time under the reserve-based credit facility is limited to the borrowing base for our oil and natural gas properties. As of December 31, 2011, our borrowing base was $125.0 million. The borrowing base is redetermined semi-annually, and may be redetermined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas prices prevailing at such time. Our next semi-annual borrowing base redetermination is scheduled during the second quarter of 2012. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders.

Borrowings under the reserve-based credit facility are available for acquisition, exploration, operation and maintenance of oil and natural gas properties, payment of expenses incurred in connection with the reserve-based credit facility, working capital and general limited liability company purposes. The reserve-based credit facility has a sub-limit of $20.0 million which may be used for the issuance of letters of credit. As of December 31, 2011, no letters of credit are outstanding.

At our election, interest for borrowings are determined by reference to (i) the London interbank rate, or LIBOR, plus an applicable margin between 2.50% and 3.50% per annum based on utilization or (ii) a domestic bank rate (ABR) plus an applicable margin between 1.50% and 2.50% per annum based on utilization plus (iii) a commitment fee of 0.50% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The reserve-based credit facility contains various covenants that limit, among other things, our ability and certain of our subsidiaries ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions.

In addition, we are required to maintain (i) a ratio of Total Net Debt (defined as Debt (generally indebtedness permitted to be incurred by us under the reserve-based credit facility) less Available Cash (generally, cash, cash equivalents, and cash reserves of the Company)) to Adjusted EBITDA (generally, for any period, the sum of consolidated net income for such period plus (minus) the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets, (gain) loss on sale of assets, exploration costs, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on derivatives and realized (gain) loss on cancelled derivatives, and other similar charges) of not more than 3.50 to 1.0; (ii) Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and (iii) consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities and current maturities of debt (to the extent such payments are not past due), of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143 (including the current liabilities in respect of the termination of oil and natural gas and interest rate swaps). All financial covenants are calculated using our consolidated financial information. The reserve-based credit facility also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, guaranties not being valid under the reserve-based credit facility and a change of control. A change of control is generally defined as the occurrence of both of the following events (i) wholly owned subsidiaries of Constellation are the owner of 20% or less of an interest in us (which has now occurred) and (ii) any person or group of persons acting in concert are the owner of more than 35% of an interest in us. If an event of default occurs, the lenders will be able to accelerate the maturity of the reserve-based credit facility and exercise other rights and remedies. The reserve-based credit facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the reserve-based credit facility and would be in default, which could cause all of our existing indebtedness to become immediately due and payable.

The reserve-based credit facility limits our ability to pay distributions to unitholders. We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the reserve-based credit facility, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the reserve-based credit facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. As of December 31, 2011, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions.

The reserve-based credit facility permits us to hedge our projected monthly production, provided that (a) for the immediately ensuing twelve month period, the volumes of production hedged in any month may not exceed our reasonable business judgment of the production for such month consistent with the application of petroleum engineering methodologies for estimating proved developed producing reserves based on the then-current strip pricing (provided that such projection shall not be more than 115% of the proved developed producing reserves forecast for the same period derived from the most recent reserve report of our petroleum engineers using the then strip pricing), and (b) for the period beyond twelve months, the volumes of production hedged in any month may not exceed the reasonably anticipated projected production from proved developed producing reserves estimated by our petroleum engineers. The reserve-based credit facility also permits us to hedge the interest rate on up to 90% of the then-outstanding principal amounts of our indebtedness for borrowed money.

The reserve-based credit facility contains no covenants related to PostRock s or Constellation s ownership in us.

At December 31, 2011, we believe that we were in compliance with the financial covenants contained in our reserve-based credit facility. We monitor compliance on an ongoing basis. As of December 31, 2011, our actual Total Net Debt to annual Adjusted EBITDA ratio was 1.5 to 1.0 as compared with a required ratio of not greater than 3.5 to 1.0, our actual ratio of consolidated current assets to consolidated current liabilities was 3.6 to 1.0 as compared with a required ratio of not less than 1.0 to 1.0, and our actual quarterly Adjusted EBITDA to cash interest expense ratio was 13.5 to 1.0 as compared with a required ratio of not less than 2.5 to 1.0.

If we are unable to remain in compliance with the debt covenants associated with our reserve-based credit facility or maintain the required ratios discussed above, we could request waivers from the lenders in our bank group. Although the lenders may not provide a waiver, we could take additional steps in the event of not meeting the required ratios or in the event of a reduction in our borrowing base, as determined by our lenders, to a level that is below our outstanding debt. During 2011, we have used our surplus operating cash flows to reduce our outstanding debt. If it becomes necessary to reduce debt by amounts that exceed our operating cash flows, we could reduce capital expenditures, suspend our quarterly distributions to unitholders, sell oil and natural gas properties, liquidate in-the-money derivative positions, reduce operating and administrative costs, or take additional steps to increase liquidity. If we become unable to obtain a waiver and were unsuccessful at reducing our debt to the necessary level, our debt could become due and payable upon acceleration by the lenders. To the extent that we do not enter into an agreement to refinance or extend the due date on the reserve-based credit facility, the outstanding debt balance at November 13, 2012, will become a current liability.

We have hedging arrangements to reduce the impact of changes in the LIBOR interest rate on our interest payments for $93.0 million of the $98.4 million outstanding on our reserve-based credit facility at February 29, 2012. These positions are outlined in Item 3. Quantitative and Qualitative Disclosures About Market Risk Interest Rate Risk.

Cash Flow from Operations

Our net cash flow provided by operating activities for the year ended December 31, 2011 was $87.7 million, compared to net cash flow provided by operating activities of $40.8 million for the same period in 2010. This increase in operating cash flow was attributable the impact of higher oil and natural gas sales of $35.9 million and the impact of lower general and administrative expenses, lease operating expenses and other expenses of $6.5 million, offset by the net working capital impact of $1.6 million in payments related to settling the Torch-related litigation. Of the increase in oil and natural gas sales of $35.9 million, $42.3 million is related to an increase in oil and natural gas hedge settlements primarily as a result of us executing a one-time transaction to reset our NYMEX fixed-for-floating price swaps for our natural gas production and $5.6 million is due to increased oil production and higher market prices for oil, offset by the impact of $12.0 million in lower natural gas production of 1.7 Bcfe and lower market prices for natural gas. Our operating expenses decreased due to lower total spending for both general and administrative expenses and lease operating expenses as a result of our 2011 cost management initiative.

During 2011, our operating cash flows were increased by $80.6 million related to cash hedge settlements for our oil and natural gas commodity and interest rate derivatives. This increase was primarily a result of us executing a one-time transaction to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production beginning in January 2012 through December 2014. In conjunction with the transaction, we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million, which was used to reduce our outstanding debt balance under our reserve-based credit facility.

Our decrease in working capital of $1.3 million from 2010 to 2011 was primarily impacted by lower accrued liabilities of $1.5 million, lower current assets of $1.0 million, higher royalty payables of $1.7 million and higher other liabilities of $0.1 million. Our accrued liabilities primarily decreased with the payments associated with our 2010 incentive compensation programs and payments to settle the Torch-related litigation. Our other current assets decreased when we used $1.0 million to purchase the NPI that was held in an escrow account as part of the settlement. Our royalties payable increased due to the impact of higher royalty payments to owners for oil production.

Our net cash flow provided by operating activities for the year ended December 31, 2010 was $40.8 million, compared to net cash flow provided by operating activities of $56.1 million for the same period in 2009. This decrease in operating cash flow was primarily attributable to lower oil and natural gas sales of $14.4 million as the result of lower production volumes combined with lower hedge settlements due to lower hedge contract prices and lower production volumes hedged, offset by higher market prices for natural gas on our unhedged production volumes. For 2010, our operating cash flows were reduced by $12.0 million due to higher oil and natural gas prices and $7.6 million in lower volumes, offset by $40.3 million related to our cash hedge settlements received for our natural gas commodity derivatives and $3.8 million paid for our interest rate derivatives. Our change in working capital from 2009 to 2010 was impacted by lower accounts receivable of $0.9 million and an increase in accounts payable of $0.3 million, partially offset by lower accrued liabilities of $0.4 million, higher prepaid expenses and lower affiliate payables of $0.2 million. Our receivables balance decreased due to increased collections and lower current period prices and sales volumes during 2010. Our accounts payable increased due to higher lease operating expenses and timing of invoice payments. The decrease in affiliate payables of $0.2 million primarily resulted from the timing of the payment for expenses incurred under the management services agreement with CEPM which was terminated December 15, 2009.

Our cash flow from operations is subject to many variables, the most significant of which are the volatility of oil and natural gas prices and our level of production of oil and natural gas. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through our development program or completing acquisitions, as well as the market prices of oil and natural gas and our hedging program. For additional information on our business plan for 2012, refer below to Outlook .

Open Commodity Hedge Positions

We enter into hedging arrangements to reduce the impact of oil and natural gas price volatility on our operations. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to fund higher severance taxes, which are usually based on market prices for oil and natural gas. Our operating cash flows are also

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impacted by the cost of oilfield services. In the event of inflation increasing service costs or administrative expenses, our hedging program will limit our ability to have increased operating cash flows to fund these higher costs. Increases in the market prices for oil and natural gas will also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to our derivative contracts is a lender in our reserve-based credit facility and we do not currently post collateral with our counterparties under any of these agreements. This is significant since we are able to lock in attractive sales prices on a substantial amount of our expected future production without posting cash collateral based on price changes prior to the hedges being cash settled.

The following tables summarize, for the periods indicated, our hedges currently in place through December 31, 2015. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps NYMEX (Henry Hub)

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2012	2,227,500	$ 5.75	2,227,500	$ 5.75	2,250,000	$ 5.75	2,250,000	$ 5.75	8,955,000	$ 5.75
2013	2,025,000	$ 5.75	2,079,500	$ 5.75	2,070,000	$ 5.75	2,038,000	$ 5.75	8,212,500	$ 5.75
2014	1,575,000	$ 5.75	1,592,500	$ 5.75	1,610,000	$ 5.75	1,610,000	$ 5.75	6,387,500	$ 5.75
									23,555,000	

MTM Fixed Price Basis Swaps CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), or Southern Star Central Gas Pipeline (Texas, Oklahoma, and Kansas)

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
2012	1,934,112	$ 0.51	1,851,025	$ 0.52	1,680,023	$ 0.54	1,462,286	$ 0.58	6,927,446	$ 0.53
2013	1,402,816	$ 0.39	1,335,077	$ 0.39	1,273,525	$ 0.39	1,223,985	$ 0.39	5,235,403	$ 0.39
2014	1,178,422	$ 0.39	1,133,022	$ 0.39	1,084,270	$ 0.39	1,047,963	$ 0.39	4,443,677	$ 0.39
									16,606,526	

MTM Fixed Price Basis Swaps West Texas Intermediate (WTI)

	For the quarter ended (in Bbls)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2012	22,238	$ 103.29	21,391	$ 103.06	20,151	$ 103.08	18,978	$ 103.14	82,758	$ 103.14
2013	17,961	$ 100.86	16,986	$ 100.88	16,060	$ 100.92	15,235	$ 100.96	66,242	$ 100.90
2014	9,317	$ 102.25	8,959	$ 102.25	8,652	$ 102.25	8,367	$ 102.25	35,295	$ 102.25
2015	8,095	$ 101.10	7,834	$ 101.10	7,588	$ 101.10	7,326	$ 101.10	30,843	$ 101.10

	215,138

All of our derivatives were accounted for as mark-to-market activities as of December 31, 2011. The net risk management asset for our commodity and interest rate derivatives was $37.2 million at December 31, 2011, as compared to a net risk management asset of $83.4 million at December 31, 2010. These values represent the fair value of our derivative positions at those respective dates. This value has declined from 2010 to 2011 primarily because of a one-time cash payment from our derivative counterparties of $41.3 million as a result of our NYMEX hedge restructuring and cash settlements on 2011 derivative positions of $39.3 million, offset by the change in the non-performance risk related to our counterparties of $0.9 million, the impact of expected future market prices for natural gas and interest rates of $32.1 million, and the addition of oil derivative positions of $1.4 million. As a result of resetting the NYMEX fixed-to-floating price to $5.75 per MMBtu for our NYMEX swap agreements from January 2012 through December 2014, we would expect that our operating cash flows and reported Adjusted EBITDA will now be lower during that timeframe. This is because of the expected decrease in the value of future cash hedge settlements on the reset NYMEX positions. We believe the expected lower operating cash flows and Adjusted EBITDA should not impact our future ability to comply with the financial covenant ratios contained in our reserve-based credit facility because we have reduced the amount of our outstanding debt.

Investing Activities Acquisitions and Capital Expenditures

Cash used in investing activities was $10.7 million for the year ended December 31, 2011, compared to $13.8 million for the same period in 2010. Our cash capital expenditures were $11.3 million in 2011, which primarily consisted of $11.0 million in development expenditures in the Cherokee Basin and the Black Warrior Basin and $0.6 million in leasing unproved properties, offset by the receipt of $0.3 million in post-closing adjustments for our December 2010 acquisition of oil properties in the Central Kansas Uplift. We completed 35 net wells and 49 net recompletions during 2011 and had 10 net wells and recompletions in progress at December 31, 2011. The uses of cash were offset by the $0.1 million in proceeds from the sale of surplus equipment and $0.5 million in distributions received from an equity investment.

Cash used in investing activities was $13.8 million for the year ended December 31, 2010, compared to $22.6 million for the same period in 2009. Our cash capital expenditures were $14.3 million in 2010, which primarily related to $7.9 million for our 2010 capital program in the Cherokee Basin and the Black Warrior Basin, $5.9 million related to the acquisition of 36 non-operated wells in the Central Kansas Uplift in Kansas and Nebraska, and $0.5 million related to the acquisition of additional interests in seven natural gas wells in the Cherokee Basin and in the Black Warrior Basin. In 2010, we drilled and completed 7 net wells, 14 net recompletions, and 10 net sidetracks in the Cherokee Basin and we had 3 net wells and 2 net sidetracks in progress. We used $1.3 million of our materials and supplies inventory in our 2010 drilling and workover programs. The uses of cash were offset by the $0.1 million in proceeds from the sale of obsolete inventory and straight-line assets and $0.5 million in distributions received from an equity investment.

The current 2012 capital budget of $15.0 million to $19.0 million is expected to be sufficient to maintain our production relatively level with our production in 2011. We expect that our current and future capital expenditures will continue to be funded using our cash flow from operations. We currently expect to focus a significant part of our 2012 capital budget on higher return oil opportunities and capital efficient recompletion opportunities. We currently believe that natural gas prices in excess of $6.00 per Mcfe produce rates of return that generally support capital spending on drilling wells that produce only coalbed methane.

The amount and timing of our capital expenditures is largely discretionary and within our control. If oil or natural gas prices decline to levels below acceptable levels, and the borrowing base under our reserve-based credit facility is reduced, drilling costs escalate, or our efforts to exploit oil potential in our asset base prove to be unsuccessful, we could choose to defer a portion of these planned capital expenditures until later periods. We routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, availability of funds under our reserve-based credit facility, and internally generated cash flow. These and other matters are outside of our control and could affect the timing of our capital expenditures. Based upon current oil and natural gas price expectations and expected 2012 production levels, we anticipate that our cash flow from operations will meet any planned capital expenditures and other cash requirements for the next twelve months. We also would have access to any available borrowing capacity under our reserve-based credit facility if additional funds are needed. Future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that our operations and other capital resources will provide cash in sufficient amounts during 2012 to maintain our planned levels of capital expenditures, to maintain the outstanding debt level under our reserve-based credit facility, or to commence, maintain or increase any quarterly distribution to unitholders. Our capital expenditures are also impacted by drilling and service costs. In the event of inflation increasing drilling and service costs, our hedging program will limit our ability to have increased revenues recoup the higher costs, which could further impact our planned capital spending.

Financing Activities

Our net cash used in financing activities was $67.7 million for the year ended December 31, 2011, compared to $30.5 million used in financing activities for the same period in 2010. During 2011, we used $66.6 million in operating cash flows to reduce our outstanding debt level, including $41.3 million in cash proceeds received when we executed a transaction to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production beginning in January 2012 through December 2014. We also used $0.3 million to fund the cost of units tendered by employees for tax withholdings for unit-based compensation and $0.7 million in additional debt issue costs associated with an amendment to our reserve-based credit facility. At December 31, 2011, we had approximately $2.4 million in debt issue costs remaining to be amortized through November 2013. Through February 29, 2012, we have reduced our outstanding debt from $165.0 million at December 31, 2010, to $98.4 million, or by 40.4%. During 2011, we did not borrow any additional daily, short-term or long-term amounts under our reserve-based credit facility.

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We suspended our $0.13 per unit quarterly distributions to unitholders for the quarter ended June 30, 2009, through the quarter ended December 31, 2011 to reduce our outstanding indebtedness. Our 2012 business plan may allow us to consider the reinstatement of a cash distribution to unitholders in 2012. All distributions are subject to the approval of our board of managers. For additional information on any resumption of our quarterly distribution, refer below to Outlook. We also suspended the $0.3 million in quarterly distributions associated with the Class D interests for each of the quarterly periods since March 31, 2008. In the fourth quarter of 2011, concurrent with the acquisition and extinguishment of the NPI, the capital account associated with the Class D interests was reduced from $6.7 million to zero. No further distributions will be made to the holder of the Class D interests.

Our net cash used by financing activities was $30.5 million for the year ended December 31, 2010, compared to $28.4 million used by financing activities for the same period in 2009. During 2010, we used $30.0 million in operating cash flows to reduce our outstanding debt level. We also used $0.4 million to fund the cost of units tendered by employees for tax withholdings for unit-based compensation and $0.1 million in payments for debt issue costs. Through December 31, 2010, we reduced our outstanding debt levels from a high of $220.0 million in 2009 to $165.0 million or by 25%. During 2010, we did not borrow any additional daily, short-term or long-term amounts under our reserve-based credit facility.

Contractual Obligations

At December 31, 2011, we had the following contractual obligations or commercial commitments:

	Payments Due By Year[(1)(2)] (in thousands)					
	2012	**2013**	**2014**	**2015**	**Thereafter**	**Total**
Reserve-Based Credit Facility	$	$ 98,400	$	$	$	$ 98,400
Support Services Agreement	569					569
Offices Leases	424	408	422	451	301	2,006
Total	$ 993	$ 98,808	$ 422	$ 451	$ 301	$ 100,975

(1) This table does not include any liability associated with derivatives.

(2) This table does not include interest as interest rates are variable. The average interest rate on our outstanding debt was approximately 5.7% at December 31, 2011.

At December 31, 2011, our asset retirement obligation was approximately $14.0 million.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements with third parties, and we maintain no debt obligations that contain provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings.

Credit Markets and Counterparty Risk

We actively monitor the credit exposure and risks associated with our counterparties. Additionally, we continue to monitor global credit markets to limit our potential exposure to credit risk where possible. Our primary credit exposures result from the sale of oil and natural gas and our use of derivatives. Through February 29, 2012, we have not suffered any material losses with our counterparties as a result of nonperformance.

Certain key counterparty relationships are described below:

Macquarie Energy LLC

Macquarie Energy LLC (Macquarie), a subsidiary of Sydney, Australia-based Macquarie Group Limited, purchases a portion of our natural gas production in the Cherokee Basin. We have received a guarantee from Macquarie Bank Limited for up to $4.0 million in purchases through December 31, 2013. As of February 29, 2012, we have no past due receivables from Macquarie.

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Scissortail Energy, LLC

Scissortail Energy, LLC (Scissortail), a subsidiary of Copano Energy, L.L.C., purchases a portion of our natural gas production in Oklahoma and Kansas. As of February 29, 2012, we have no past due receivables from Scissortail.

ONEOK Energy Services Company, L.P.

ONEOK Energy Services Company, L.P. (ONEOK), a subsidiary of ONEOK, Inc., purchases a portion of our natural gas production in Oklahoma and Kansas. We have received a guarantee from ONEOK, Inc. for up to $3.0 million in purchases through November 30, 2012. As of February 29, 2012, we have no past due receivables from ONEOK.

J.P. Morgan Ventures Energy Corporation

J.P. Morgan Ventures Energy Corporation purchases the majority of our natural gas production in Alabama. The payment for the purchases is guaranteed by JP Morgan Chase & Company through June 30, 2014. As of February 29, 2012, we have no past due receivables from J.P. Morgan Ventures Energy Corporation.

Derivative Counterparties

As of February 29, 2012, all of our derivatives are with BNP Paribas, The Royal Bank of Scotland plc, Societe Generale, The Bank of Nova Scotia, and ING Capital Markets LLC. These derivative counterparties are lenders, or affiliated with a lender, in our reserve-based credit facility. All of our derivatives are currently collateralized by the assets securing our reserve-based credit facility and therefore currently do not require the posting of cash collateral. As of February 29, 2012, each of these financial institutions has an investment grade credit rating. BNP Paribas, The Royal Bank of Scotland plc, and Societe Generale are on review for a possible downgrade by Moody s Investor Service. However, it would take a multiple ratings downgrade for each of these banks to fall below investment grade.

Reserve-Based Credit Facility

As of February 29, 2012, the banks and their percentage commitments in our reserve-based credit facility are: The Royal Bank of Scotland plc (26.84%), BNP Paribas (21.95%), The Bank of Nova Scotia (21.95%), ING Capital LLC (14.63%), and Societe Generale (14.63%). As of February 29, 2012, each of these financial institutions has an investment grade credit rating.

Outlook

During 2012, we expect that our business will continue to be affected by the factors described in Item 1A. Risk Factors, as well as the following key industry and economic trends. Our expectation is based upon key assumptions and information currently available to us. To the extent that our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Full Year 2012 Expected Results

Our 2012 business plan and forecast will be focused on potentially resuming our quarterly distribution to unitholders, prioritizing oil production in the execution of our capital program, actively managing our operating expenses and maintaining a debt balance relative to our existing asset base of below $100.0 million. We currently expect our operating environment to be characterized by continued low natural gas prices and increasing cost pressures, including higher service costs and healthcare costs.

For 2012, we currently anticipate:

- Our production to be between 13.3 Bcfe and 14.1 Bcfe, approximately 69% of which is currently hedged at prices that are attractive relative to the price levels we currently observe in the commodity markets.

Our operating expenses to be actively managed, resulting in a range of $42.5 million to $46.0 million.

Our Adjusted EBITDA to be in a range of $29.5 million to $31.5 million.

Our total capital expenditures to be between $15.0 million to $19.0 million. We expect to drill and recomplete wells primarily in the Cherokee Basin. We expect to actively review our drilling and recompletion opportunities and anticipate allocating capital to the highest value-added projects across all of our available opportunities, emphasizing oil opportunities to the extent available in the Cherokee Basin.

Our operating cash flows to allow for an outstanding debt level relative to our existing asset base of below $100.0 million.

Our quarterly distributions to our unitholders to be potentially resumed during 2012. All future quarterly distributions must be approved by our board of managers.

Impact of 2012 Plan

Our 2012 operating plan is intended to generate sufficient operating cash flows to consider the reinstatement of a quarterly distribution to our unitholders while making sufficient capital expenditures for our 2012 production to remain relatively level with our 2011 production. We expect that this plan will maintain or improve our operational performance and our liquidity position. Achievement of the objectives in this plan would allow us the ability to grow our business by making additional incremental accretive acquisitions of oil and natural gas properties. We will look for additional opportunities to create long-term value and to generate stable cash flows thereby allowing us to make quarterly distributions to our unitholders.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions. The results of these estimates and assumptions form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of our financial statements. Below, we have provided a discussion of certain critical accounting policies, estimates and judgments. Please read Note 1 to our consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for our oil and natural gas exploration, development and production activities. Under this method of accounting, costs relating to leasehold acquisition, property acquisition, and the development of proved areas are capitalized when incurred. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Geological, geophysical and dry hole costs relating to unsuccessful exploratory wells are charged to expense as incurred.

Depreciation and depletion of producing oil and natural gas properties is recorded based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. The acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs (including wells and related equipment and facilities) are amortized on the basis of proved developed reserves. As more fully described in Note 15 to the consolidated financial statements, proved reserves estimates are subject to future revisions when additional information becomes available.

Estimated asset retirement costs are recognized when the asset is acquired or placed in service, and are amortized over proved reserves using the units-of-production method. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. Cash flow estimates for the impairment testing are based on third party reserve reports and exclude derivative instruments. Refer to Note 5 to our consolidated financial statements for additional information.

Unproven properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred. Impairment is deemed to have occurred if a lease is going to expire prior to any planned drilling on the leased property. Valuation allowances based on average lease lives are maintained for the value of unproved properties. For our concession in Osage County, Oklahoma, we assess it for impairment on a quarterly basis, and if it is considered impaired, a charge to expense is made when such impairment is deemed to have occurred.

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Oil and Natural Gas Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate with reasonable certainty to be recoverable from established reservoirs in the future under current operating and economic parameters. Management estimates the proved reserves attributable to our ownership based on various factors, including consideration of reserve reports prepared by NSAI, an independent petroleum engineering firm. On an annual basis, our proved reserve estimates and the reserve report prepared by NSAI are reviewed by the audit committee of our board of managers and our board of managers. Our 2011, 2010, 2009 and 2008 financial statements were prepared using NSAI s estimates of our proved reserves while our 2007 and 2006 financial statements were prepared using our internal estimates of our proved reserves.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. We prepared our reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the actual quantities of oil and natural gas eventually recovered.

Revenue Recognition

Sales are recognized when oil and natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Oil and natural gas is generally sold on a monthly basis. Most of the contracts pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a specific tank battery, gathering or transmission line, quality of oil and natural gas, and prevailing supply and demand conditions, so that the price of the oil and natural gas fluctuates to remain competitive with other available oil and natural gas supplies. As a result, revenues from the sale of oil and natural gas will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our oil and natural gas contracts are customary in the industry.

Gas imbalances occur when sales are more or less than the entitled ownership percentage of total gas production. Any amount received in excess is treated as a liability. If less than the entitled share of the production is received, the excess is recorded as a receivable. There were no material gas imbalance positions at December 31, 2011, 2010, and 2009.

Hedging Activities

We have implemented a hedging program to limit our exposure to changes in commodity prices or basis differentials for our oil and natural gas sales and to mitigate the impact of volatility of changes in the LIBOR interest rate on the interest payments for our debt. We do not enter into speculative trading positions.

We account for all our open derivatives as mark-to-market activities using the mark-to market accounting method. Using this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions Risk management assets and Risk management liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of income under the caption Gain/(loss) from mark-to-market activities , which is a component of our total revenues for commodity derivatives or other income for interest rate derivatives.

We experience earnings volatility as a result of using the mark-to-market accounting method. This accounting treatment can cause earnings volatility as the positions related to future oil and natural gas production or future interest payments are marked-to-market. These non-cash unrealized gains or losses are included in our current Statement of Operations and Comprehensive income (loss) until the derivatives are cash settled as the commodities are produced and sold or the interest is paid. Increases in the market price of oil or natural gas and interest rates relative to the fixed future prices for our hedges result in unrealized, non-cash mark-to-market losses on those derivatives and lower reported net income. Decreases in the market price of oil or natural gas or interest rates relative to the fixed future prices for our hedges result in unrealized, non-cash mark-to-market gains on those derivatives and higher reported net income. Although these gains and losses are required to be reported immediately in earnings as market prices change, the fair value of the related future physical transaction is not marked-to-market and therefore is not reflected as revenues or expenses or as an accounts receivable or accounts payable in our financial statements. This mismatch impacts our reported results of operations and our reported working capital position until the derivatives are cash settled and the future physical transaction occurs. Upon cash settlement of the derivatives, the sale of the physical commodity or interest payment at then-current market prices offsets the previously reported mark-to-market gains or losses such that the cumulative net cash realized results in a net sale of the physical oil and natural gas production or interest payment at the fixed future prices for our hedge. When our derivative positions are cash settled, the realized gains and losses of those derivative positions are included in our statement of operations as natural gas sales, oil and liquids sales, or interest expense depending on the derivative.

If we were to account for our derivatives as cash flow hedges, we would record changes in the fair value of derivatives designated as hedges that are effective in offsetting the variability in cash flows of forecasted transactions in other comprehensive income until the forecasted transactions occur. At the time the forecasted transactions occur, we would reclassify the amounts recorded in other comprehensive income into earnings. We would record the ineffective portion of changes in the fair value of derivatives used as hedges immediately in earnings. When amounts for hedging activities are reclassified from Accumulated other comprehensive income (loss) on the balance sheet to the Statement of Operations and Comprehensive income (loss), we would record settled natural gas derivatives as Oil and gas sales and settled interest rate swaps as Interest expense (income).

Recent Accounting Pronouncements and Accounting Changes

In June 2011, the FASB issued ASU 2011-05, *Comprehensive Income (Topic 220)* that requires entities to present net income and other comprehensive income in either a single continuous statement or in two separate, but consecutive, statements of net income and other comprehensive income. The option to present items of other comprehensive income in the statement of changes in equity is eliminated. The amended guidance is effective for us in the first quarter of 2012 and will not have any material impact on our financial statements or our disclosures.

In May 2011, the FASB issued ASU 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs*, and the IASB issued IFRS 13, *Fair Value Measurement* (together, the new guidance). The new guidance results in a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between U.S. GAAP and IFRS. The new guidance changes some fair value measurement principles and disclosure requirements. and is effective for interim and annual periods beginning on or after December 15, 2011. The amended guidance is effective for us in the first quarter of 2012 and we do not believe that this guidance will have any material impact on our financial statements or our disclosures.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Global Financial and Energy Markets

The U.S. economy continues to show signs of improvement, but the level of improvement has been insufficient to materially increase the demand for natural gas, which accounts for a majority of our production. Concurrently, production from shale gas plays has increased the supply of natural gas in the U.S. and inventories of natural gas in storage remain at record high levels. As a result, future expected prices for natural gas remain depressed relative to the price levels observed at the time our assets were acquired. At the same time, oil prices have dramatically increased in part due to unrest in the Middle East.

We expect that our ability to issue debt and equity securities may continue to be limited over the next year. We also anticipate that the borrowing base of our reserve-based credit facility could be further reduced, particularly if future expected market prices for natural gas prices remain depressed or decline further, thereby reducing our borrowing base. We have suspended our cash distribution since June 2009 and lowered our maintenance capital spending in 2009, 2010, and 2011. This lower maintenance capital spending has resulted in declining production which lowered our future operating cash flows. We currently expect that our 2012 capital expenditures will be sufficient to maintain our production relatively level with our production in 2011. Until natural gas prices show signs of a sustained recovery, we anticipate that the majority of our capital spending will be focused on any oil opportunities in our existing asset base as well as our most capital efficient recompletion opportunities. If market prices for natural gas remain depressed or oil prices decrease, our future cash flows from operations will be reduced for our unhedged production. We continue to monitor the financial and energy markets to determine if we should further revise the timing and scope of our future drilling programs, financing activities, and acquisition activities to determine the impact of these activities on the potential reinstatement of our distributions to unitholders.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas production and, to some extent, our oil production. Realized pricing is primarily driven by the NYMEX (Henry Hub) and Inside FERC prices for Southern Natural Gas Company (Louisiana) with respect to our properties in the Black Warrior Basin and the Inside FERC prices for CenterPoint Energy Gas Transmission (East), Natural Gas Pipeline Company of America (Midcontinent), the CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), Panhandle Eastern Pipe Line (Texas, Oklahoma) and Southern Star Central Gas Pipeline (Texas, Oklahoma, Kansas) with respect to our properties in the Cherokee Basin, the Inside FERC price for the CenterPoint Energy Gas Transmission (East) for our properties in the Woodford Shale, NYMEX West Texas Intermediate (Cushing, Oklahoma) for our oil production and the spot market prices applicable to all of our oil and natural gas production. Historically, pricing for oil and natural gas has been volatile and unpredictable and we expect this volatility to continue in the future. We are currently operating in an environment characterized by low natural gas prices which tends to lower the revenues that we realize on our unhedged natural gas production and limit the amount of operating cash flows available for maintenance capital expenditures, distributions to unitholders, or further debt reduction, if warranted. The prices we receive for oil and natural gas production depend on many factors outside our control, including weather, economic conditions, and the total supply of oil and natural gas available for sale in the market.

We have entered into hedging arrangements with respect to a portion of our projected future production through various derivatives that hedge the future prices received. These hedging activities are intended to support commodity sales prices at targeted levels and to manage our exposure to commodity price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes. The use of hedging transactions also involves the risk that one or more of the counterparties will be unable to meet the financial terms of the transactions executed. We attempt to minimize this risk by entering into our derivative transactions with counterparties that are lenders, or affiliated with a lender, in our reserve-based credit facility. The table below presents the hypothetical changes in fair values arising from potential changes in the quoted market prices of the commodity underlying the derivative instruments used to mitigate these market risks. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the sale of the hedged production, which are not included in the table. These derivatives do not hedge all of our commodity price risk related to our forecasted sales of oil and natural gas production and, as a result, we are subject to commodity price risk on our remaining unhedged oil and natural gas production.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	**Fair Value**	**(Decrease)**	**Fair Value**	**Increase**
			(in 000 s)		
Impact of changes in commodity prices on derivative commodity instruments at December 31, 2011	$ 42,026	$ 33,884	$ (8,142)	$ 50,168	$ 8,142

Interest Rate Risk

At December 31, 2011, the one-month LIBOR rate was 0.295%, the three-month LIBOR rate was 0.581%, and our applicable margin on LIBOR borrowings was 3.25%. At December 31, 2011, the ABR rate was 3.25%, and our applicable margin on ABR borrowings was 2.25%. At December 31, 2011, we had debt outstanding of $98.4 million. This amount incurred interest at various LIBOR rates plus an applicable margin of 3.25% based on utilization. We had no debt outstanding at the ABR rate. At December 31, 2011, the carrying value and fair value of our debt is $98.4 million.

The table below presents the hypothetical changes in fair values arising from potential changes in the quoted interest rate underlying the derivative instruments used to mitigate these market risks.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	**Fair Value**	**Increase**	**Fair Value**	**(Decrease)**
			(in 000 s)		
Impact of changes in LIBOR on derivative interest rate instruments at December 31, 2011	$ (4,804)	$ (4,284)	$ 520	$ (5,324)	$ (520)

We enter into hedging arrangements to reduce the impact of volatility of changes in the LIBOR interest rate on our interest payments for $93.0 million of our outstanding debt balance of $98.4 million at February 29, 2012. If we reduce our outstanding debt balance to $93.0 million or lower, our cash interest costs for our effective LIBOR rate would begin to approximate the settlements on these interest rate swaps. At December 31, 2011, we have the following outstanding interest rate swaps that fix our LIBOR rate:

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Maturity Date	Total Debt Hedged (in 000 s)	LIBOR Fixed Rate
August 20, 2014	$ 11,000	2.370%
September 20, 2014	$ 31,000	2.520%
October 19, 2014	$ 23,500	2.680%
October 22, 2014	$ 7,500	2.610%
November 20, 2014	$ 14,000	2.535%
November 20, 2014	$ 6,000	2.690%

Item 8. Financial Statements and Supplementary Data

The Reports of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required to be filed under this item are presented in PART IV. Item 15. Exhibits and Financial Statement Schedules of this Annual Report on Form 10-K, and are incorporated herein by reference.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and the Chief Financial Officer of CEP have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of December 31, 2011 (the Evaluation Date). Based on such evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that, as of the Evaluation Date, our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and is accumulated and communicated to our management, including our Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

During the three months ended December 31, 2011, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), was enacted into law. The Dodd-Frank Act provides non-accelerated filers with a permanent exemption from the requirement to obtain an external audit on the effectiveness of internal financial reporting controls provided in Section 404(b) of the Sarbanes-Oxley Act. We utilized this exemption under the Dodd-Frank Act for the year ended December 31, 2011. We still disclosed management s assessment of the effectiveness of internal control over financial reporting as required in Section 404(a) of the Sarbanes-Oxley Act. The amendment to the Sarbanes-Oxley Act was effective immediately and is intended to reduce compliance costs for smaller companies. The use of this exemption was reviewed and approved by our audit committee.

Report of Management

Financial Statements

The management of Constellation Energy Partners LLC (our , the Company or CEP) is responsible for the information and representations in our financial statements. We prepare the financial statements in accordance with accounting principles generally accepted in the United States of America based upon available facts and circumstances and management s best estimates and judgments of known conditions.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the financial statements and expressed their opinion on the financial statements. They performed their audit in accordance with the standards of the Public Company Accounting Oversight Board

(United States).

The audit committee of our board of managers, which consists of three independent managers, meets periodically with management, our internal auditor, and PricewaterhouseCoopers LLP to review the activities of each in discharging their responsibilities. Our internal auditor and PricewaterhouseCoopers LLP have free access to the audit committee.

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Management s Report on Internal Control Over Financial Reporting

Our management, under the direction of our principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rule 13a-15(f).

Our system of internal control over financial reporting is designed to provide reasonable assurance to our management and board of managers regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

Our management conducted an evaluation of the effectiveness of our internal control over financial reporting using the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable-not absolute-assurance to management and the board of managers regarding achievement of an entity s financial reporting objectives. Based upon the evaluation under this framework, management concluded that our internal control over financial reporting was effective as of December 31, 2011.

Item 9B. Other Information

None.

PART III

Item 10. Managers, Executive Officers and Corporate Governance

The following table shows information for members of our board of managers and our executive officers as of December 31, 2011. Members of our board of managers are elected for one year terms, and our executive officers will hold office at the discretion of, and may be removed by, our board of managers in its discretion.

Name	Age	Position with Constellation Energy Partners LLC
Richard H. Bachmann	59	Independent manager
Stephen R. Brunner	53	Chief Executive Officer, Chief Operating Officer and President
John R. Collins	54	Manager
Michael B. Hiney	43	Chief Accounting Officer and Controller
Richard S. Langdon	61	Chairman of the Board and independent manager
Hugh M. McIntosh	66	Manager
Lisa J. Mellencamp	56	General Counsel and Secretary
John N. Seitz	60	Independent manager
Charles C. Ward	51	Chief Financial Officer and Treasurer

Richard H. Bachmann has been an independent member of our board of managers and our audit, compensation, conflicts, and nominating and governance committees and chair of our conflicts committee since November 2006. Mr. Bachmann joined the general partner (the General Partner) of Enterprise Products Partners L.P. (Enterprise) and Enterprise Products Company, a privately-held affiliate of Enterprise, as Executive Vice President, Chief Legal Officer and Secretary in January, 1999. Mr. Bachmann resigned such positions in November 2010. Also since January 1999, Mr. Bachmann has served as a Director of Enterprise Products Company. He previously served as a Director of the General Partner from June 2000 to January 2004 and was re-elected and continued as a Director of the General Partner from February 2006 until April 2010. Mr. Bachmann was elected Group Vice Chairman, Chief Legal Officer and Secretary of Enterprise Products Company in December 2007. Since April 2010, Mr. Bachmann has been and continues as the President and Chief Executive Officer of Enterprise Products Company. From August 2005 until April, 2010, Mr. Bachmann served as Executive Vice President, Chief Legal Officer and Secretary of EPE Holdings LLC, the sole general partner of Enterprise GP Holdings L.P., a publicly-traded partnership and an affiliate of Enterprise. Mr. Bachmann was also elected a Director of EPE Holdings in February 2006. In April 2010, Mr. Bachmann resigned his positions as Chief Legal Officer and Secretary of EPE Holdings LLC, but remained as a director and an Executive Vice President of that company until its merger with and into a subsidiary of Enterprise. After the merger in November 2010, Mr. Bachmann was elected a director of the post-merger general partner of Enterprise. In October 2006, Mr. Bachmann was elected President, Chief Executive Officer and a Director of DEP Holdings LLC, the sole general partner of Duncan Energy Partners L.P., a publicly-traded partnership, but resigned those positions in April 2010 to devote more time to his position at Enterprise Products Company. All of the foregoing entities perform various transportation and other services to the energy and petrochemical industries. Prior to joining Enterprise Products Company in 1999, Mr. Bachmann served as a Partner in the law firms of Snell & Smith P.C. from

1993 to 1998 and Butler & Binion from 1988 to 1993.

Stephen R. Brunner was a member of our board of managers from March 2008 until August 2011 and serves as our Chief Executive Officer, Chief Operating Officer, and President. He was appointed President and Chief Executive Officer of CEP in March 2008 and became an employee of the company in January 2009. He continues to serve in the role of Chief Operating Officer of the Company, a role he assumed in February 2008. Mr. Brunner has over 25 years of experience operating oil and gas properties both domestically and internationally. Prior to joining CEP, Mr. Brunner also served as a Vice President for CCG, where he provided support for CEP in various operational activities. Prior to joining CCG in February 2008, Mr. Brunner served as the Executive Vice President of Operations for Pogo Producing Company, where he was responsible for all aspects of exploration, production, acquisition and divestiture activity for seven business units in the United States, Canada, New Zealand and Vietnam. During his 13-year tenure at Pogo, Mr. Brunner also served as Vice President of Operations, overseeing both domestic and international operations. He served as the Resident Manager of Thaipo Limited, a subsidiary of Pogo, as well as Offshore Operations Manager. Prior to his career with Pogo, he held various positions with Zilkha Energy Company, Chevron Corporation and Tenneco Oil Company.

John R. Collins has been a member of our board of managers since November 2006. Since August 2011, Mr. Collins has served as the Chief Financial Officer of Enduring Hydro, LLC, a privately held company which provides strategic advice on and investments in hydroelectric and other clean energy generation. Mr. Collins served as Senior Vice President of Constellation Energy Group, Inc., or Constellation, from October 2008 to December 2010. Prior to that, Mr. Collins was the Chief Financial Officer of Constellation from May 2007 to October 2008 and a member of Constellation s Executive Committee, a Senior Vice President of Constellation from January 2004 to July 2007 and Constellation s Chief Risk Officer from December 2001 to January 2008. Mr. Collins was also Managing Director-Finance and Treasurer of Constellation Power Source Holdings, Inc. from January 2000 to December 2001. From February 1997 to December 2001, Mr. Collins served as the senior financial officer of CCG. Mr. Collins is the former Chairman of the Board of the Committee of Chief Risk Officers, an energy industry association of risk management professionals.

Michael B. Hiney has served as our Chief Accounting Officer and Controller since March 2008 and became an employee of the Company in January 2009. Mr. Hiney has over 20 years of energy industry and energy related accounting and finance experience. He served as a Vice President of CCG from July 2006 until December 2008 where he served as Controller for CEP and helped to lead the company through its initial public offering in November 2006. During the 16 years prior to that time, he held various positions at El Paso Exploration and Production Company, including Director and Assistant Controller from January 2004 to June 2006.

Richard S. Langdon has been an independent member of our board of managers and our audit, compensation, conflicts, and nominating and governance committees and chair of our audit committee since November 2006 and the chairman of our board of managers since October 2011. Mr. Langdon is also currently the President, Chief Executive Officer and Chairman of KMD Operating Company LLC (KMD Operating), a position held since November 2011, and President and Chief Executive Officer of Sigma Energy Ventures, LLC (a position held since November 2007), each of which is a privately held exploration and production company. Mr. Langdon was the President and Chief Executive Officer of Matris Exploration Company L.P., a privately held exploration and production company (Matris Exploration), from July 2004 and Executive Vice President and Chief Operating Officer of KMD Operating from August 2009 until the merger of Matris Exploration into KMD Operating in November 2011, which merger was effective January 2011. From 1997 until 2002, Mr. Langdon served as Executive Vice President and Chief Financial Officer of EEX Corporation, a publicly traded exploration and production company that merged with Newfield Exploration Company in 2002. Prior to that, Mr. Langdon held various positions with the Pennzoil Companies from 1991 to 1996, including Executive Vice President International Marketing Pennzoil Products Company; Senior Vice President Business Development Pennzoil Company; and Senior Vice President Commercial & Control Pennzoil Exploration & Production Company. Mr. Langdon also serves as a director of Gasco Energy, Inc., a publicly traded exploration and production company.

Hugh M. McIntosh has been a member of our board of managers since August 2011. Since June 2010, Mr. McIntosh has served as Head of School of Episcopal High School of Baton Rouge, Louisiana. Mr. McIntosh served as Head of School of Keystone School in San Antonio, Texas from January 2004 to June 2010, an educational consultant from 2002 to 2003, and as Chaplain at Punahou School in Honolulu, Hawaii from July 2001 to June 2002. Mr. McIntosh was formerly a lawyer and partner at the law firm of Vinson & Elkins LLP from 1973 to 1998 in Houston, Texas and Washington, D.C., where he was active in the energy transactions practice for approximately 25 years and had responsibilities for the operation and administration of the firm s Washington, D.C. office for approximately 10 years. In 1998, Mr. McIntosh withdrew from Vinson & Elkins LLP to attend Harvard Divinity School and obtained a Master of Divinity in 2001. Mr. McIntosh has extensive civic and charitable involvement and has served on the boards of several non-profit entities providing arts and services to the community.

Lisa J. Mellencamp has served as our General Counsel and Secretary since January 2009. Ms. Mellencamp has over 25 years of legal experience with an extensive energy background. She served as Associate General Counsel for Constellation Energy Resources from March 2008 until December 2008 and as Senior Counsel of CCG from March 2005 to February 2008. Prior to that time she was Associate General Counsel at Duke Energy Americas from July 2003 to March 2005. Earlier in her career, she was Assistant General Counsel at Enron North America Corporation and served as a partner in the law firm of Gardere Wynne Sewell LLP from 1998 to 1999 and Hutcheson & Grundy L.L.P. from 1988 to 1998.

John N. Seitz has been an independent member of our board of managers and our audit, compensation, conflicts, and nominating and governance committees and chair of our compensation and nominating and governance committees since November 2006. Mr. Seitz is also currently Vice Chairman of the Board of Directors of Endeavour International Corporation, a publicly traded oil and gas exploration and production company which he founded in February 2004, and a director for ION Geophysical Corporation, f/k/a Input Output, Inc., a publicly traded provider of seismic products and services. In February 2004, Mr. Seitz co-founded Endeavour International Corporation and served as its co-Chief Executive Officer until September 2006. Prior to founding Endeavour International Corporation, Mr. Seitz served as Chief Executive Officer, President and Chief Operating Officer of Anadarko Petroleum Corporation from January 2002 to March 2003, and prior to being named Chief Executive Officer, President and Chief Operating Officer, Mr. Seitz was the Chief Operating Officer and President of Anadarko Petroleum Corporation beginning in 1999. Mr. Seitz also served as Anadarko Petroleum Corporation s Executive Vice President, Exploration and Production and as a member of its board of directors from 1997 to 1999.

Charles C. Ward was appointed chief financial officer and treasurer of CEP in March 2008 and became an employee of the Company in January 2009. Mr. Ward has over 15 years of finance and energy industry experience. Prior to joining CEP, Mr. Ward also served as a vice president for CCG from November 2005 to December 2008 where he provided support for CEP in various finance activities and helped to lead the company through its initial public offering in November 2006. Prior to joining CCG in November 2005, Mr. Ward was a Vice President of Enron North America Corporation from March 2002 to November 2005. Prior to that time, Mr. Ward also held various positions at Enron North America Corporation, El Paso Corporation, and Tenneco Corp.

Determination of Independence

A majority of our managers are required to be independent in accordance with NYSE Amex listing standards, the exchange to which we transferred our listing in February 2012. For a manager to be considered independent, the board of managers must affirmatively determine that such manager has no material relationship with us. When assessing the materiality of a manager s relationship with us, the board of managers considers the issue from both the standpoint of the manager and from that of persons and organizations with whom or with which the manager has an affiliation. The board of managers has adopted standards to assist it in determining if a manager is independent. A manager will be deemed to have a material relationship with us and will not be deemed to be an independent manager if:

- A manager who is an employee (other than as an interim executive officer for less than one year), or whose immediate family member (defined below) is an executive officer, of the Company is not independent until three years after the end of such employment relationship;

- A manager who receives, or whose immediate family member receives, more than $120,000 in any 12-month period in direct compensation from the Company (other than manager and committee fees, compensation paid to an immediate family member who is an employee, compensation paid for service as an interim executive officer for less than one year, benefits under a tax-qualified retirement plan or non-discretionary compensation) is not independent until three years after receiving more than $120,000 in such compensation in a 12-month period;

- A manager who is or whose immediate family member is a current partner or was a partner or employee of the outside auditor of the Company is not independent until three years after the end of such relationship;

- A manager who is employed, or whose immediate family member is employed, as an executive officer of another entity where any of the Company s executive officers serve on that entity s compensation committee is not independent until three years after the end of such service or the employment relationship; or

A manager who is, or whose immediate family member is, a partner, a controlling shareholder or an executive officer of an organization that makes payments to, or receives payments from, the Company in an amount which, in any single fiscal year, exceeds the greater of $200,000, or 5% of such other organization s consolidated gross revenues, is not independent until three years after falling below such threshold.

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An immediate family member includes a person s spouse, parents, children, siblings, mothers- and fathers-in-law, sons- and daughters-in-law, brothers- and sisters-in-law, and anyone (other than domestic employees) who resides in said person s home.

Each of Messrs. Bachmann, Langdon and Seitz is independent under the NYSE Amex listing standards. In addition, the audit, compensation and nominating and corporate governance committees are composed entirely of independent managers in accordance with NYSE Amex listing standards, SEC requirements and other applicable laws, rules and regulations. Other than as set forth below, there are no transactions, relationships or other arrangements between us and our independent managers that need to be considered under the NYSE Amex listing standards in determining that such managers are independent.

We sold natural gas from the Black Warrior Basin to an affiliate of EPCO Inc. in each of 2011, 2010, and 2009. Mr. Bachman is an executive officer of EPCO Inc. As the sales did not exceed 2% of the consolidated gross revenues of EPCO Inc. at any time during those periods, the board of managers determined that the relationship was immaterial and did not impair Mr. Bachmann s independence.

Qualifications of Board of Managers

At the time of our initial public offering in November 2006, Class A and Class B managers were selected to serve on our board of managers. CEPM appoints two Class A managers and our Class B unitholders elect three Class B managers. Some of the key criteria for serving on our board of managers as a Class B manager include independence from Constellation and PostRock, experience in the E&P industry, familiarity with master limited partnerships, and corporate governance, financial, or other management experience. Our Class B managers, and the specific experience, qualifications, attributes and skills that led the board to conclude that they should serve as managers, are:

Mr. Seitz brings to our board significant managerial and operational experience in the oil and gas industry. He is the current vice chairman of Endeavor International Corporation, a publicly traded oil and gas exploration company, and has served as the chief executive officer of Anadarko Petroleum, one of the largest independent oil and gas companies in North America. His specialized technical experience in the oil and gas industry adds significant value to the board s contribution to our performance. He also has prior public company board experience, which is beneficial for the operations of our board, and currently serves as a director of ION Geophysical Corporation, a publicly traded provider of seismic services to the E&P industry, and as a director of Gulf United Energy, Inc., a publicly traded independent energy company with interests in international oil and natural gas properties. Mr. Seitz is independent of Constellation and PostRock.

Mr. Langdon brings to our board considerable financial and managerial experience in the energy industry as well as his entrepreneurial abilities, which are valuable to a small company such as us. He has served as the chief financial officer of EEX Corporation, a publicly traded exploration and production company that merged with Newfield Exploration. He has also held significant commercial positions with the Pennzoil Companies, including roles in business development and marketing. He is also the founder and owner of two privately held oil and gas companies. Mr. Langdon has extensive experience in finance and accounting that adds significant value to the board s oversight role of our financial reporting. He has prior public company board and audit committee experience, which is beneficial for our board operations, and currently serves as the chairman of the audit committee of Gasco Energy, Inc., a publicly traded exploration and production company. Mr. Langdon is independent of Constellation and PostRock.

Mr. Bachmann brings to our board significant experience in the master limited publicly traded partnership sector and extensive legal and corporate governance skills. Mr. Bachmann has had a long-time affiliation with the Enterprise family of master limited partnerships, a large and successful group of energy-focused master limited partnerships. He has served in key leadership roles for Enterprise and its affiliates, including chief legal officer, director, president and chief executive officer. His experiences with Enterprise contribute to our board s understanding of the business model for master limited partnerships. His experience and knowledge of legal affairs and corporate governance in the energy industry contributes to the efficiency and effectiveness of our board. Mr. Bachmann is independent of Constellation and PostRock.

CEPM has appointed Messrs. Collins and McIntosh as our two Class A managers to represent its interests on our board. Our Class A managers, and the specific experience, qualifications, attributes and skills that led CEPM and the board to conclude that they should serve as managers, are:

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Mr. Collins brings to our board his substantial experiences in risk management, finance and investor relations. He was a long-time Constellation employee who has held various executive-level positions with the diversified energy firm, including leadership roles in finance and risk management. He has valuable historical perspectives on our growth and operations. He contributes cross-industry experience and depth of knowledge of finance, risk management, and corporate processes which offers our board important insights into the role of finance and risk management in our business and strategy. He adds value to the board oversight role of investor communications. He acts as a liaison with PostRock and ensures our board has continuing dialogue with our largest unitholder.

Mr. McIntosh brings to our board his significant professional, educational, and charitable experiences. He was a partner with the Vinson & Elkins LLP law firm where he developed an in-depth understanding of project finance, mergers and acquisitions, and corporate law. These experiences contribute to our ability to achieve our business plans and objectives, particularly those dealing with our capital structure and developing growth and expansion strategies, including the potential acquisition of additional properties through mergers and acquisitions. Mr. McIntosh has an exemplary educational background and has earned degrees from Harvard University, the University of Virginia, and Mississippi State University. He also has extensive civic and charitable involvement and has served on the boards of several non-profit entities providing arts and services to the community. These diverse educational, leadership and charitable experiences contribute to the capabilities of our board to act efficiently and effectively. He acts as a liaison with PostRock and ensures our board has continuing dialogue with our largest unitholder.

Since our initial public offering, all of our Class B managers have been reelected by our unitholders. CEPM elects its Class A managers concurrent with our annual meeting.

Corporate Governance

Board Leadership Structure and Risk Oversight

Our board has three independent members as Class B managers and two managers appointed by CEPM as Class A managers. One of our independent managers, Richard S. Langdon, is currently our non-executive chairman of the board. Our independent board members are currently serving or have served as members of senior management of other public companies and have served as managers or directors of other public companies. We have four board committees comprised solely of independent managers, each with an independent manager serving as chair of the committee. We believe that the number of independent, experienced managers that make up our board, along with the oversight of the board by an independent manager who is a non-executive chairman of the board, benefits our company and our unitholders.

Under our Second Amended and Restated Operating Agreement, as amended, and corporate governance guidelines, the chairman of the board is responsible for

- chairing board meetings;
- scheduling and setting the agendas for these meetings and
- providing information to board members in advance of each board meeting.

In addition, the board of managers has designated the chairman of the nominating and corporate governance committee, John N. Seitz, to act as Lead Manager. The Lead Manager has the following duties and authority:

- presiding at all board meetings where the Chairman of the board of managers is not present;
- serving as a liaison between the Chairman of the board of managers and the independent managers;

- approving (i)information sent to the board and (ii) agendas and meeting schedules for board meetings;
- calling meetings of the non-management managers;
- ensuring his availability for direct consultation upon request of a major unitholder;
- chairing the executive session of non-management managers; and
- serving as a contact for unitholder complaints, other than those involving auditing/accounting matters.

Interested parties may communicate directly with Mr. Seitz in his capacity as Lead Manager by writing to the Secretary, Constellation Energy Partners LLC, 1801 Main Street, Suite 1300, Houston, Texas 77002.

In accordance with NYSE Amex requirements, our audit committee charter provides that the audit committee is responsible for overseeing the risk management function in the company. While the audit committee has primary responsibility for overseeing risk management, our entire board of managers is actively involved in overseeing risk management for the company. For example, on at least a quarterly basis, our audit committee and our full board receive a risk management report from the company s chief financial officer. The full board also engages in periodic discussion with other company officers as the board may deem appropriate. In addition, each of our board committees considers the risks within its area of responsibilities. For example, our compensation committee considers the risks that may be implicated by our executive compensation programs. We believe that the leadership structure of our board supports the board s effective oversight of our risk management.

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On an annual basis, as part of our review of corporate governance, the board evaluates our board leadership structure to ensure that it remains the optimal structure for our company and our unitholders. We recognize that different board leadership structures may be appropriate for companies with different histories and cultures, as well as companies with varying sizes and performance characteristics. We believe our current leadership structure under which Mr. Langdon, an independent manager, serves as chairman of the board, the board committees are chaired by independent managers and a lead manager assumes specified responsibilities remains the optimal board leadership structure for our company and our unitholders at this time.

During 2011, the board of managers met 9 times. Each manager attended at least 75% of the meetings of the board and of each committee on which he served.

The board of managers has adopted a policy that encourages each manager to attend the annual meeting of unitholders. All of the persons then serving as our managers attended the 2011 Annual Meeting of Unitholders.

Committees of the Board of Managers

Audit Committee

As described in the audit committee charter, the audit committee is directly responsible for the appointment, compensation, retention and oversight of the work of the independent public accountants to audit our financial statements, including assessing the independent auditor s qualifications and independence, and establishes the scope of, and oversees, the annual audit. The committee also approves any other services provided by public accounting firms. The audit committee provides assistance to the board in fulfilling its oversight responsibility to the unitholders, the investment community and others relating to the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor s qualifications and independence and the performance of our internal audit function. The audit committee oversees our system of disclosure controls and procedures and system of internal controls regarding financial, accounting, legal compliance and ethics that management and our board of managers established. In doing so, it will be the responsibility of the audit committee to maintain free and open communication between the committee and our independent auditors, the internal accounting function and management of our company.

The board of managers has determined that the chairman of the audit committee is an audit committee financial expert as that term is defined in the applicable rules of the SEC. The audit committee held 5 meetings in 2011. Mr. Langdon is Chairman, and Messrs. Seitz and Bachmann are members.

Compensation Committee

As described in the compensation committee charter, the compensation committee establishes and reviews general policies related to our compensation and benefits. The compensation committee determines and approves, or makes recommendations to the board of managers with respect to, the compensation and benefits of our board of managers and our named executive officers and employees.

The compensation committee held 8 meetings in 2011. Mr. Seitz is Chairman, and Messrs. Bachmann and Langdon are members.

Conflicts Committee

Our board of managers has established a conflicts committee to review specific matters that the board believes may involve conflicts of interest, including transactions with related persons such as PostRock and Constellation or their respective affiliates or our managers and executive officers. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to our Company. Our limited liability company agreement provides that members of the conflicts committee may not be officers or employees of our Company, or directors, officers or employees of any of our affiliates, and must meet the independence standards for service on an audit committee of a board of directors as established by NYSE Amex and SEC rules. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to our Company and approved by all of our unitholders. However, the board is not required by the terms of our limited liability company agreement to submit the resolution of a potential conflict of interest to the conflicts committee, and may itself resolve such conflict of interest if the board determines that (i) the terms of the related person transaction are no less favorable to us than those generally being provided to or available from unrelated third parties or (ii) the transaction is fair and reasonable to us, taking into account the totality of the relationships between the parties involved. Any matters approved by the board in this manner will be deemed approved by all of our unitholders.

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The conflicts committee held 6 meetings in 2011. Mr. Bachmann is Chairman, and Messrs. Seitz and Langdon are members.

Nominating and Governance Committee

As described in the nominating and governance committee charter, the nominating and governance committee nominates candidates to serve on our board of managers. The nominating and governance committee is also responsible for monitoring a process to review manager, board and committee effectiveness, developing and implementing our corporate governance guidelines, recommending committee members and committee chairpersons and otherwise taking a leadership role in shaping the corporate governance of our company.

The nominating and governance committee held 4 meetings in 2011. Mr. Seitz is Chairman, and Messrs. Bachmann and Langdon are members.

We maintain on our website, *www.constellationenergypartners.com*, copies of the charters of each of the committees of the board of managers (except the conflicts committee which does not have a charter), as well as copies of our Corporate Governance Guidelines, Code of Ethics for Chief Executive Officer, Chief Financial Officer and Principal Accounting Officer, and Code of Business Conduct and Ethics. Copies of these documents are also available in print upon request of our Corporate Secretary. The Code of Business Conduct and Ethics provides guidance on a wide range of conduct, conflicts of interest and legal compliance issues for all of our managers, officers and employees, including the chief executive officer, chief financial officer and chief accounting officer. We will post any amendments to, or waivers of, the Code of Business Conduct and Ethics applicable to our Chief Executive Officer, Chief Financial Officer or Principal Accounting Officer on our website.

Nominations for Manager

The board of managers seeks diverse candidates who possess the background, skills and expertise to make a significant contribution to the board of managers, us and our unitholders. Annually, the nominating and corporate governance committee reviews the qualifications and backgrounds of the managers, as well as the overall composition of the board of managers, and recommends to the full board of managers the slate of Class B manager candidates to be nominated for election at the next annual meeting of unitholders. The board of managers has adopted a policy whereby the nominating and corporate governance committee will consider the recommendations of unitholders with respect to candidates for election to the board of managers and the process and criteria for such candidates will be the same as those currently used by us for manager candidates recommended by the board of managers or management.

Our Corporate Governance Guidelines, a copy of which is maintained on our website, *www.constellationenergypartners.com*, include criteria that are to be considered by the nominating and corporate governance committee and board of managers in considering candidates for nomination to the board of managers. These criteria require that a candidate:

- has the business and/or professional knowledge and experience applicable to us, our business and the goals and perspectives of our unitholders;
- is well regarded in the community, with a long-term, good reputation for highest ethical standards;
- has good common sense and judgment;
- has a positive record of accomplishment in present and prior positions;
- has an excellent reputation for preparation, attendance, participation, interest and initiative on other boards on which he or she may serve; and
- has the time, energy, interest and willingness to become involved with us and our future.

Within our Corporate Governance Guidelines there is no specific requirement that the nominating and corporate governance committee or the board of managers consider diversity in identifying candidates for nomination to the board of managers.

A unitholder who wishes to recommend to the nominating and corporate governance committee a nominee for manager for the 2012 Annual Meeting of Unitholders should submit the recommendation in writing to the Secretary, Constellation Energy Partners LLC, 1801 Main Street, Suite 1300, Houston, Texas 77002 so it is received by June 14, 2012 but not earlier than May 15, 2012.

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Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires our directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of ownership of our equity securities and reports of changes in ownership of our equity securities with the SEC. Such persons are also required by SEC regulation to furnish us with copies of all Section 16(a) forms they file.

Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and managers, we believe that during 2011 all Section 16(a) reporting persons complied with all applicable filing requirements in a timely manner.

Certifications

The NYSE Amex requires the Chief Executive Officer of each listed company to certify annually that he is not aware of any violation by the company of the NYSE Amex s corporate governance listing standards, qualifying the certification to the extent necessary. In accordance with the rules of the NYSE Amex, we will provide such a certification within 30 days after our 2012 annual meeting. We filed our 2011 certification with NYSE Arca within 30 days of our 2011 annual meeting. The certifications of our Chief Executive Officer and Chief Financial officer required by Sections 302 and 906 of the Sarbanes-Oxley Act have been included as exhibits to our Annual Report on Form 10-K which was filed on February 29, 2012.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Overview

This compensation discussion and analysis provides a description of the material elements of our executive compensation programs, as well as perspective and context for decisions made during 2011 regarding the compensation for our named executive officers who are identified below:

- Mr. Stephen R. Brunner, Chief Executive Officer, Chief Operating Officer and President
- Mr. Charles C. Ward, Chief Financial Officer and Treasurer
- Ms. Lisa J. Mellencamp, General Counsel and Secretary
- Mr. Michael B. Hiney, Chief Accounting Officer and Controller

Executive Summary

Our overall compensation structure is designed to align our executive s compensation with our business strategies and annual business plan that is approved by our board of managers. We maintain a compensation mix that includes a fixed base salary, short-term annual performance-based cash bonus awards, and long-term incentives including unit-based compensation.

During 2011, our Company s performance exceeded or achieved the metrics and goals set forth in our 2011 business plan that was approved by our board of managers. Most importantly, we have successfully reduced our debt from a high of $220.0 million in 2009 to $98.4 million at December 31, 2011. This reduction in outstanding debt, combined with our operational performance, reductions in our operating expenses and the success of our capital expenditure program, may allow us to consider the reinstatement of a cash distribution to unitholders in 2012.

Compensation Philosophy

Our compensation philosophy is founded on the guiding principles that the Company s compensation programs will be:

aligned with the long-term interest of the company s unitholders;

performance-based to motivate strong company and individual performance and reward management for achieving results;

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competitive with market practices to enable the company to attract and retain management and technical talent;

flexible to optimize the value and efficiency of compensation programs; and

transparent, straightforward, and well-communicated to facilitate a strong understanding by all stakeholders, both internally and externally.

In developing our compensation program, we have considered: 1) the necessity of transitioning and inducing our management from being employees of an affiliate of our former sponsor to being employees of our company, 2) the positioning of our company in its life cycle to ensure that we have the necessary leadership, experience and technical skills to operate our company, 3) the current competitive environment for oilfield executive and managerial talent, and 4) the Company s performance.

Our compensation policies are also intended to focus the efforts of our named executive officers and our employees on the achievement of our 2011 business plan which included both operational and financial targets. The actual compensation awarded to individuals is generally based on the company s achievement of its annual business plan that was reviewed and approved by our board of managers as well as each individual s contribution toward meeting the plan.

Role of the Compensation Committee, Board of Managers, and Management

Our compensation committee consists of three managers who are all independent under the independence standards established by NYSE Amex and SEC rules. The committee establishes and reviews general policies related to our compensation and benefits, and annually reviews and approves the compensation paid to our executive officers and non-employee managers. The committee also approves the annual performance-based bonus award pool and long-term incentive equity awards for all employees.

Our chief executive officer makes recommendations to the compensation committee regarding the compensation for the executive officers, other than himself. Specific recommendations include base salary adjustments, targets and goals for the annual performance-based bonus plan, and long-term incentive awards. The committee considers and, in its sole discretion, makes the final determination about compensation actions for the chief executive officer. The committee also recommends to our board of managers compensation actions for the other executive officers, which our board of managers, in its sole discretion, finally determines.

When assessing compensation actions for the chief executive officer and the other executive officers, the compensation committee considers several factors including comparative market data, the level of achievement of our annual business plan, our performance against our peer group, individual executive officer performance, scope of job responsibilities, and the individual s industry experience, technical skills and tenure with the Company.

Role of the Compensation Consultant

Our compensation committee is authorized to retain compensation consultants at Company expense and obtain any compensation surveys or reports regarding the design and implementation of compensation programs that it may find necessary in designing, implementing or administering compensation programs. During 2011, the committee retained Meridian Compensation Partners, LLC (Meridian). The committee confirmed the retention of Meridian after a review of the independence factors included in the Dodd-Frank Wall Street Reform and Consumer Protection Act for compensation consultants and considering Meridian s independence based on such factors. The amount paid to Meridian in 2011 was less than $150,000.

Benchmarking Compensation

During the first quarter of 2011, the compensation committee reviewed the compensation levels for our named executive officers. The committee examined comparable market compensation data contained in oil and gas exploration and production (E&P) industry compensation surveys and an executive compensation analysis prepared by Meridian. As part of this review, Meridian assessed the overall competitiveness of the compensation of our named executives relative to a peer group of E&P companies selected based on several factors including assets, revenues, reserves, standardized measure, market capitalization, enterprise value, and scope of operations. The resulting peer group used to benchmark compensation for the named executive officers included the following companies:

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- Brigham Exploration Company;
- Carrizo Oil & Gas, Inc.;
- Crimson Exploration Inc.;
- Gastar Exploration Ltd.;
- GMX Resources Inc.;
- PetroQuest Energy, Inc.;
- PostRock Energy Corporation;
- Rosetta Resources Inc.;
- Stone Energy Corporation; and
- Vanguard Natural Resources, LLC.

The compensation committee believes the peer companies provide an overall fit with our geographic footprint and our strategic focus on unconventional natural gas resources.

The E&P industry surveys indicated that the 2010 compensation levels for our named executive officers were below median levels of comparable companies. The Meridian analysis confirmed that the target total compensation for our named executive officers was positioned below the 25th percentile of peer benchmark levels. Additional review of E&P industry survey data indicated that the 2010 compensation levels for our named executive officers were below median levels of comparable companies.

Based on these outcomes, the compensation committee undertook actions for 2011 that would narrow the gap between our compensation levels and the benchmark median. As discussed below, the compensation committee increased the 2011 base salaries for our named executive officers and granted unit-based awards under our 2009 Omnibus Incentive Compensation Plan to our named executive officers. These actions were necessary in order to make our compensation more comparable with market practices and to enable the Company to retain management and operational and technical talent needed to operate the business.

Elements of Compensation

With the help of our compensation consultant, we have developed a compensation mix that includes 1) a fixed base salary, 2) short-term annual performance-based cash bonus awards, and 3) long-term incentives including unit-based compensation.

The following is a discussion of the major components of our compensation program:

Fixed Base Salary

Our fixed base salaries are intended to provide a market-competitive level of cash compensation to recognize the skills and experience of our named executives. Base salaries are reviewed annually with adjustments made based on market conditions, individual performance, and internal equity considerations.

During 2010, in light of market conditions and our desire to reduce expenses to provide for additional funds to reduce our outstanding debt level, the compensation committee determined it would be appropriate to freeze base salaries at the 2009 levels for our named executive officers and all employees except for salary increases related to promotions. This contributed to base salaries for certain of our employees falling below comparable market salaries, including the named executive officers. For 2011, the compensation committee approved ten percent increases to the base salaries for our named executive officers to improve their overall competitive positioning; specifically, the 2011 base salaries for the named executives are as follows:

Mr. Brunner	$330,000
Mr. Ward	$247,500
Ms. Mellencamp	$220,000
Mr. Hiney	$192,500

Following these increases, Mr. Brunner s base salary remains below the 25th percentile of benchmark peer group base salary levels; Messrs. Ward and Hiney and Ms. Mellencamp are positioned approximately 10% below median benchmark peer group base salary levels.

Short-term Annual Performance-Based Bonus Awards

We maintain a short-term annual performance-based bonus award program covering all of our employees, including our named executive officers. The goal of our performance-based bonus award program is to motivate and reward both financial and operational contributions for the achievement of our annual business plan. Our annual business plan is reviewed and approved by our board of managers. Our compensation committee establishes the annual performance-based bonus award pool at the end of the year after reviewing the Company s performance during the year. The target and maximum bonus opportunities specified for our named executive officers were based on Meridian s input and market data. The target bonus opportunities (as a percentage of base salary) were generally set at the median of the respective peer group benchmarks. Target bonus opportunities in 2011 for each of the named executives are specified as a percentage of his or her base salary, pursuant to their employment agreements, as follows:

Mr. Brunner 100%

Mr. Ward 75%

Ms. Mellencamp 65%

Mr. Hiney 55%

The target bonus opportunities generally approximate the median of each named executive s respective peer group benchmark levels and, when applied to base salaries, are intended to target total cash compensation near median peer group benchmark levels. The named executives may earn up to two times their target bonus opportunity based on the Company s performance. Earned short-term cash performance-based awards are paid in March of the following year. Prior to payment of any awards, the compensation committee is required to review and confirm the Company s performance against our annual business plan to determine and approve the recommended level of performance-based awards for the chief executive officer. The full board of managers is required to perform the same review to determine and approve the recommended level of performance-based awards for the named executive officers other than our chief executive officer.

For 2011 the compensation committee reviewed the Company s performance and approved the payout of bonus awards for our named executive officers at 130% of target levels for each named executive officer, as follows:

Mr. Brunner $429,000

Mr. Ward $241,313

Ms. Mellencamp $185,900

Mr. Hiney $137,638

These payouts are based, in the compensation committee s and board of managers sole discretion and business judgment, upon satisfactory achievement of our 2011 business plan goals, including those relating to production, operating expenses, drilling capital efficiency, debt reduction, and the Company s corporate strategy, as well as positioning the Company to consider reinstating a cash distribution to unitholders in 2012 and developing an inventory of oil opportunities for the Company. The compensation committee and the board of managers also considered the individual performance of each named executive. Specific individual performance considerations were as follows:

Mr. Brunner implementation of our Company strategy, demonstrated ability to improve our operational execution, capital efficiency, risk management and financial performance, and ability to manage the organization to focus on personnel safety, environmental stewardship and regulatory compliance;

Mr. Ward management of the Company s borrowing base, reduction in the Company s debt balance to below $100.0 million, leadership of the Company s business development and acquisition activities, and execution of our risk management plans;

Ms. Mellencamp support in organizing Company records, additional responsibilities of supervising land staff and environmental, health and safety matters, and efforts to favorably resolve outstanding litigation and legal matters; and

Mr. Hiney leadership of the accounting and tax functions, efforts to consolidate the Company s accounting outsource providers, the reduction of costs for administrative and overhead functions, and efforts to comply with SEC disclosure changes, trends and best practices.

Long-term Incentives

Our long-term incentive program is intended to encourage our named executive officers, key employees, and consultants to focus on our long-term performance and to align their interests with the interests of our unitholders. The program also provides an opportunity for increased equity ownership, which fosters retention, and assists in maintaining competitive levels of total compensation. Long-term incentive awards are made pursuant to the 2009 Omnibus Incentive Compensation Plan, which was adopted and approved by our board of managers on April 28, 2009, and approved by our common unitholders on December 1, 2009. The plan provides for a variety of unit-based and performance-based awards, including unit options, restricted units, unit grants, notional units, unit appreciation rights, performance awards and other unit-based awards. Awards under the plan may be paid in cash, units, or any combinations thereof as determined by the compensation committee.

In 2011, the compensation committee approved grants of unit-based awards to each of the named executive officers. The number of unit-based awards granted to each named executive was determined based on the committee s assessment of competitive long-term incentive awards and the intent to target the total compensation of each of the named executive officers near their respective median benchmark levels. Below are the unit awards granted to the named executive officers in 2011(each unit has a value of $100):

Mr. Brunner 10,000 units

Mr. Ward 3,500 units

Ms. Mellencamp 3,000 unit

Mr. Hiney 1,500 units

Pursuant to these awards, which will be settled in cash, executives may earn between 0% and 200% of the number of units granted based on the achievement of absolute CEP unit price targets during a three-year performance period from January 2011 through December 2013. The selection of price targets as the performance metric for the unit-based awards is intended to align the compensation of the named executive officers with the creation of value for our unitholders and an increase in the trading price of our units. Accordingly, awards may be earned based on the following schedule which defines CEP unit price targets and corresponding cash payout levels:

Threshold 50% cash payout at $3.50/CEP unit

Target 100% cash payout at $4.00/CEP unit

Stretch 200% cash payout at $6.00/CEP unit

Cash payouts for results between these points will be interpolated on a linear basis. Failure to achieve the threshold CEP unit price will result in no cash payout of the awards granted. The determination of the level of achievement and number of unit-based awards earned will be based on a calculation of CEP s unit price at the end of the performance period. This price calculation will be based on the average of the closing daily prices for the final 20 trading days of the performance period. In addition, the unit-based awards will vest earlier if any of the following events occur: a change of control, a CEG ownership event, death of the executive, delivery by the Company of a disability notice with respect to the executive, or an involuntary termination of the executive (with each of the foregoing terms having the corresponding definitions set forth in the respective employment agreement with the Company). As of February 29, 2012, none of such events has yet occurred. Any cash payment will be made at the end of the performance period except in the case of certain change of control events, which may accelerate payment. The program is intended to benefit our unitholders by focusing the recipient s efforts on increasing our absolute unit price over the performance period.

Executive Inducement Bonus Program

In 2009, an Executive Inducement Bonus Program of 300,000 common units was adopted and approved by our board of managers without unitholder approval in reliance on the exemption provided in NYSE Arca rule 5.3(d)(5)(A). The units granted under this program are the unit-based component of the one-time inducement bonuses for our named executive officers described below. After the vesting of 125,615 common units to our named executives (50% on January 1, 2010 and 50% on January 1, 2011), we cancelled the 174,385 units which were unissued under the program.

In 2009, to encourage employees of our former sponsor to become employees of CEP, we adopted a one-time, inducement sign-on bonus program that was paid to our named executives in a combination of approximately 75% in cash and approximately 25% in unit-based compensation, as well as to certain other key employees in 100% cash. The inducement bonuses vested 50% on January 1, 2010 and 50% on

January 1, 2011. These inducement bonuses were intended to encourage retention and to provide a bridge from our former sponsor s compensation policies to those of CEP and were a key part of the effort to transition the remaining employees and services being provided by our former sponsor under a management services agreement to us. For our named executive officers, the inducement bonus was also intended to bring their total compensation for 2009 to just above the 50th percentile of the peer group industry median according to a survey done by our compensation consultant at such time. Without the inducement awards, their total compensation, assuming a target performance bonus award, would have been from approximately 10% to 20% below the peer group industry median. The unit-based component of the inducement bonuses for our named executive officers was also intended to align management with the interest of our unitholders. Messrs. Brunner, Ward and Hiney and Ms. Mellencamp received cash and unit inducement awards in an aggregate amount of $616,727, $462,546, $359,758, and $411,150, respectively (based on the grant date fair value of the unit awards). The amount of the awards was based on the compensation committee s discretion of an appropriate amount and represented approximately 200% of their annual base salary. This program, which has been discontinued, was successful in retaining our named executives through the second anniversary of their employment on January 1, 2011.

Other Compensation Policies

Company Benefits

Our named executive officers are eligible to participate in Company benefit plans such as medical, dental, life, and disability insurance, 401k and flexible spending accounts on the same terms as all our employees.

Perquisites

We do not provide any perquisites for our named executive officers.

Unit Ownership Requirements

We do not require specific unit ownership targets for our named executive officers or managers. However, each of the named executive officers currently maintains significant ownership in the Company.

Hedging Policies

We have a policy that does not allow speculative or proprietary trading of derivatives that create incentives to engage in risky activities that fall outside of our annual business plan. We also have a policy that prohibits employees or managers from purchasing any financial instruments that are designed to hedge or offset any decease in the market value of our units granted to them as compensation or otherwise held directly or indirectly by them.

Compensation Risk Assessment

Our compensation committee has a risk assessment process for compensation programs and found no policies or practices that would rise to the level of being reasonably likely to have a material adverse effect on the Company. We believe our compensation programs do not encourage our employees to take excessive risks to achieve larger performance-based bonus awards or additional unit-based compensation above their individual targets.

Clawback Provisions

The employment contracts with our four named executive officers contain clawback provisions. In the event of a restatement of our financial statements that are filed with the SEC, our executives must refund the amounts actually paid by us for the performance-based bonus award for the two years immediately prior to such restatement that exceed the amounts that the committee determines, in its discretion, should have been paid for those two years based on the financial results reflected in the restated financial statements. In the event there has been a final and non-appealable judgment entered by a court of competent jurisdiction that found willful misconduct by an executive in the performance of his or her duties prior to the termination of his or her employment, all payments made in the event of a voluntary or involuntary termination must be refunded.

2012 Compensation Actions

In the fourth quarter of 2011, the compensation committee requested that Meridian conduct an updated competitive review of the compensation for our named executives. The analysis of base salary, target bonus opportunity, target cash compensation, annualized grant value of long-term incentives, and target total compensation was based on public disclosures from their selected peer group used to benchmark 2011 compensation. The review was based on an assessment of these peer companies and included an analysis of total assets, revenues, standardized measure, reserves, market capitalization, enterprise value, and scope of operations. Meridian determined that no changes to the peer group used for 2011 compensation benchmarking were necessary as the peer group provides an effective working range of competitive compensation information. The review indicated that the aggregate total compensation for our named executives is 24% below our peer benchmark median levels and is generally aligned with the 25th percentile of peer companies. Our target total cash compensation is also positioned 26% below median levels. Competitive positioning of our targeted long-term incentive award values varied by named executive but in the aggregate is positioned between the 25th percentile and the median of market levels. However, the compensation committee has not yet taken any actions with respect to the compensation arrangements for our named executive officers for 2012.

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Summary Compensation Table

The following table sets forth the compensation of our named executive officers for 2011, 2010 and 2009:

Name and Principal Position	Year	Salary	Cash Bonus[(a)]	Unit Grants[(b)]	All Other Compensation[(c)]	Total
Stephen R. Brunner	2011	$ 330,000	$ 429,000	$ 262,100	$ 248,095	$ 1,269,195
Chief Executive Officer, Chief Operating Officer, and President[(d)]	2010	$ 300,000	$ 300,000	$ 808,176	$ 248,260	$ 1,656,436
	2009	$ 300,000	$ 300,000	$ 1,563,672	$ 18,492	$ 2,182,164
Michael B. Hiney	2011	$ 192,500	$ 137,638	$ 39,315	$ 141,904	$ 511,357
Chief Accounting Officer and Controller[(d)]	2010	$ 175,000	$ 96,250	$ 88,396	$ 141,916	$ 501,562
	2009	$ 175,000	$ 70,000	$ 253,429	$ 10,726	$ 509,155
Lisa J. Mellencamp	2011	$ 220,000	$ 185,900	$ 78,630	$ 165,916	$ 650,446
General Counsel and Secretary[(d)]	2010	$ 200,000	$ 130,000	$ 202,047	$ 167,340	$ 699,387
	2009	$ 200,000	$ 130,000	$ 463,309	$ 12,538	$ 805,847
Charles C. Ward	2011	$ 247,500	$ 241,313	$ 91,735	$ 184,847	$ 765,395
Chief Financial Officer and Treasurer [(d)]	2010	$ 225,000	$ 168,750	$ 269,392	$ 187,015	$ 850,157
	2009	$ 225,000	$ 168,750	$ 651,531	$ 12,988	$ 1,058,269

(a) The amount in this column reflects each named employee s annual cash incentive bonus earned for 2011, 2010 and 2009 performance. The annual cash incentive bonuses were determined by our compensation committee based on assessments of both Company and individual performance. The amounts for each of Messrs. Brunner, Hiney, and Ward and Ms. Mellencamp were awarded in recognition of the achievement of overall performance at a target level.

(b) The amount in this column reflects the grant date fair value of all unit awards in 2011, 2010, and 2009 calculated in accordance with FASB ASC Topic 718. These unit awards vest between 2012 and 2015. See Part IV. Exhibits and Financial Statements Schedules Notes to Consolidated Financial Statements-12. Unit-Based Compensation for further information.

(c) The amount in this column reflects the vested amount of the cash portion of the one-time inducement sign-on bonus during 2011 and 2010, and the amount of matching contributions made to each employee under our 401k plan and the cost of life insurance equal to the executive officer s salary for 2011, 2010, and 2009. The cash portion of the one-time inducement sign-on bonus for Messrs. Brunner, Ward and Hiney and Ms. Mellencamp was $225,000, $168,750, $131,250, and $150,000, respectively. The 401k plan portion for Messrs. Brunner, Ward and Hiney and Ms. Mellencamp was $22,000, $10,015, $15,185 and $15,276, respectively. The cost of life insurance for Messrs. Brunner, Ward and Hiney and Ms. Mellencamp was $1,095, $639, $731, and $821, respectively.

(d) Our named executive officers are eligible to participate in Company benefit plans such as medical, dental, life, and disability insurance, 401k and flexible spending accounts on the same terms as all our employees.

Grants of Plan-Based Awards for 2011

The following table sets forth the grants of plan-based awards to our named executive officers for 2011:

Name		Grant date	Compensation Committee approval date	Unit-Based Awards; number of units	Grant date fair value of units
Stephen R. Brunner	(a)	4/19/2011	4/19/2011	10,000	$ 262,100
				10,000	$ 262,100
Michael B. Hiney	(a)	4/19/2011	4/19/2011	1,500	$ 39,315
				1,500	$ 39,315
Lisa J. Mellencamp	(a)	4/19/2011	4/19/2011	3,000	$ 78,630

				3,000	$	78,630
Charles C. Ward	(a)	4/19/2011	4/19/2011	3,500	$	91,735
				3,500	$	91,735

(a) These are unit-based awards issued under the 2009 Omnibus Incentive Compensation Plan. See Compensation Discussion and Analysis Elements of Compensation Long-Term Unit-Based Compensation 2009 Omnibus Incentive Compensation Plan.

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Outstanding Equity Awards at Fiscal Year-End

The following table sets forth the outstanding equity awards and their market value using the closing price of our common units at December 31, 2011 for our named executive officers:

	Outstanding Equity Awards at December 31, 2011			
Name	Number of Restricted Units Not Vested	Number of Unit-Based Awards Not Vested	Fair Market Value of Units Not Vested	Vesting Dates
Stephen R. Brunner	89,323		$ 175,073	1/1/2012
	178,650		$ 350,154	50% from 2013 to 2014
	186,862		$ 366,250	25% from 2012 to 2015
		10,000	$ 128,600	12/31/2013
	454,835	10,000	$ 1,020,077	
Michael B. Hiney	9,773		$ 19,155	1/1/2012
	19,548		$ 38,314	50% from 2013 to 2014
	20,439		$ 40,060	25% from 2012 to 2015
		1,500	$ 19,290	12/31/2013
	49,760	1,500	$ 116,819	
Lisa J. Mellencamp	22,330		$ 43,767	1/1/2012
	44,665		$ 87,543	50% from 2013 to 2014
	46,717		$ 91,565	25% from 2012 to 2015
		3,000	$ 38,580	12/31/2013
	113,712	3,000	$ 261,455	
Charles C. Ward	33,496		$ 65,652	1/1/2012
	66,995		$ 131,310	50% from 2013 to 2014
	62,288		$ 122,084	25% from 2012 to 2015
		3,500	$ 45,010	12/31/2013
	162,779	3,500	$ 364,056	

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Vested Equity Awards for the Fiscal Year

The following table sets forth the outstanding equity awards and their market value using the closing price of our common units on the vesting date for our named executive officers that were realized by each named executive officer in 2011:

	Number of Restricted Common Units Acquired on Vesting	Value Realized on Vesting
Stephen R. Brunner	163,953	$ 463,062
Michael B. Hiney	31,166	$ 88,363
Lisa J. Mellencamp	52,618	$ 148,910
Charles C. Ward	70,003	$ 198,107

Employment Agreements

As part of the transition, we entered into definitive employment agreements on May 1, 2009, with each of our named executive officers. Pursuant to the terms of the employment agreements, each named executive officer received in 2011:

Name	Base Salary	Bonus Target	Maximum Bonus	Unit Based Awards (a)	50% of Inducement Bonus Vesting on 1/1/2011
Stephen R. Brunner	$ 330,000	100%	200%	10,000 units	$225,000 cash and 26,979 restricted common units
Michael B. Hiney	$ 192,500	55%	80%	1,500 units	$131,250 cash and 15,738 restricted common units
Lisa J. Mellencamp	$ 220,000	65%	130%	3,000 units	$150,000 cash and 17,986 restricted common units
Charles C. Ward	$ 247,500	75%	150%	3,500 units	$168,750 cash and 20,234 restricted common units

(a) Each of our named executive officer s employment agreement includes the right to participate in the 2009 Omnibus Incentive Compensation Plan. Any annual grants of unit-based compensation under the plan are determined by the compensation committee and the board of managers.

Termination of Employment

Each executive s employment may be terminated at any time and for any reason by either or both of the company and the executive. Except as described below, if the executive terminates his or her employment, all unvested or unearned awards will be forfeited. If the executive s employment is terminated in connection with an Involuntary Termination at any time prior to a change of control of the company or after two years have elapsed following a change of control, the company will, pursuant to the terms of the employment agreements, make payments and take actions as follows (such payments and actions, the Severance Amount):

- make a cash payment of (i) one and one-half times the executive s then-current annual compensation, which includes (A) the target-level bonus plus (B) the greater of the annual base salary in effect on the date of the Involuntary Termination or the annual base salary in effect 180 days prior to the Involuntary Termination;

- cause any unvested awards granted under the Plan to become immediately vested and cause any and all nonqualified deferred compensation to become immediately nonforfeitable; and

- cause a continuation of medical and dental benefits for one year following the Involuntary Termination.

If the executive s employment is terminated (i) by the executive through the exercise of the Special Termination Option (described below) or (ii) in connection with an Involuntary Termination during the two-year period following a change of control of the Company, the Company will, pursuant to the terms of his or her Employment Agreement, make payments and take actions as follows (such payments and actions, the

Enhanced Severance Amount);

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make a cash payment of (i) two times the executive s then-current annual compensation, which includes (A) the target level bonus plus (B) the greater of the annual base salary in effect on the date of the Involuntary Termination, the annual base salary in effect 180 days prior to the Involuntary Termination, or the annual base salary in effect immediately prior to the change of control, plus (iii) the performance award and target-based grants payable under the Plan for the then-current year, paid as if the target-level performance was achieved for the entire year, prorated based on the number of whole or partial months completed at the time of the Involuntary Termination;

cause any unvested awards granted under the 2009 Omnibus Incentive Compensation Plan to become immediately vested and cause any and all nonqualified deferred compensation to become immediately nonforfeitable;

cause a continuation of medical and dental benefits for one year following the change of control; and

provide for a full tax gross-up in connection with any excise tax levied on the items described in the preceding three bullets.

The Special Termination Option permits each executive to terminate his or her employment at any time within the one-year period following the acquisition by Constellation or its affiliates of at least 49% of our outstanding common units.

The Severance Amount and Enhanced Severance Amount are contingent on the execution of a release of any claims the terminated executive may have against us and our affiliates. In addition, any such amounts must be repaid if a final and non-appealable judgment is entered by a court of competent jurisdiction finding that the executive s conduct in performance of his or her duties under the employment agreement constituted willful misconduct.

The initial term of the employment agreements will expire on the third anniversary of each employment agreement unless sooner terminated in accordance with the employment agreement. If the agreements have not otherwise been terminated prior to the expiration of the initial term, the employment agreements will automatically be extended for an additional one-year period unless either party to such employment agreement delivers written notice 180 days prior to the expiration of the initial term. We guaranteed the obligations of CEP Services Company, Inc. under the employment agreements.

Potential Payments Upon Voluntary Termination, Involuntary Termination or Change In Control

As of December 31, 2011, we have employment agreements in place that provide for payments to the named executive officers in connection with certain voluntary or involuntary terminations of the individual or a change in control of CEP. The following table summarizes the value of these provisions of these employment agreements if the named executive officer is entitled to a severance amount because of an involuntary termination (including a resignation by the officer for an event of good reason thereunder) other than during a change of control as of December 31, 2011:

	Severance Amount			
Name	**Cash Value of Salary and Bonus**	**Market Value of Units To Be Vested (a)**	**All Other Compensation(b)**	**Total Severance**
Stephen R. Brunner	$ 990,000	$ 891,477	$ 22,339	$ 1,903,816
Michael B. Hiney	$ 447,563	$ 97,530	$ 7,567	$ 552,660
Lisa J. Mellencamp	$ 544,500	$ 222,876	$ 21,191	$ 788,567
Charles C. Ward	$ 649,688	$ 319,047	$ 22,339	$ 991,074

(a) The market value of the unit-based awards is $0 assuming a change of control occurred on December 31, 2011. The company s unit price closed at $1.96 per unit on the nearest trading date, which is below the minimum price of $3.50 per unit for a cash payout award. Refer to 2009 Omnibus Incentive Compensation Plan above for additional information on the grants of unit-based awards made under this plan.

(b) All Other Compensation represents the value of medical and dental insurance for one year.

The following table summarizes the value of these provisions of these employment agreements if the named executive officer is entitled to an enhanced severance amount because of an involuntary termination (including a resignation by the officer for an event of good reason thereunder) during a change of control period or the named executive terminates his or her employment within a one year period following the acquisition by

Constellation or its affiliates of at least 49% of our outstanding common units as of December 31, 2011:

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Name	Cash Value of Salary and Bonus	Market Value of Units To Be Vested[(a)]	Enhanced Severance Amount All Other Compensation[(b)]	Excise Tax[(c)]	Total Enhanced Severance
Stephen R. Brunner	$ 1,650,000	$ 891,477	$ 22,339	$	$ 2,563,816
Michael B. Hiney	$ 702,625	$ 97,530	$ 7,567	$	$ 807,722
Lisa J. Mellencamp	$ 869,000	$ 222,876	$ 21,191	$	$ 1,113,067
Charles C. Ward	$ 1,051,875	$ 319,047	$ 22,339	$	$ 1,393,261

(a) The market value of the unit-based awards is $0 assuming a change of control occurred on December 31, 2011. The company s unit price closed at $1.96 per unit on the nearest trading date, which is below the minimum price of $3.50 per unit for a cash payout award. Refer to 2009 Omnibus Incentive Compensation Plan above for additional information on the grants of unit-based awards made under this plan.

(b) All Other Compensation represents the value of medical and dental insurance for one year.

(c) Excise tax is calculated in accordance with IRS Regulation 1.280G-1 and using 2011 Form W-2 income from CEP Services Company, Inc.

Compensation of Managers

Our board of managers, based on recommendations from our compensation committee, input from Meridian, and a 2007 Towers Perrin report for the compensation committee, approved the following individual non-employee manager annual cash compensation program:

- $40,000 annual retainer for each manager;
- the chairman of the board of managers will receive a $50,000 annual retainer (commencing October 25, 2011) and the chairman of the audit committee will receive a $10,000 annual retainer;
- $2,500 fee for each meeting of the board of managers and each committee meeting attended by a member thereof that occurs on a day when there is no board meeting; and
- reasonable travel expenses to attend meetings.

Our board of managers, based on recommendations from our compensation committee, input from Meridian, and a 2007 Towers Perrin report for the compensation committee, also approved the following non-employee manager unit-based compensation program:

- Each non-employee manager will receive an annual restricted common unit award with a value of $75,000, to be granted as of March 1 of each year, such award to have a one-year vesting period and to be forfeited on a pro-rata basis if service as a manager terminates prior to the one-year vesting period. The compensation committee and the board of managers may elect to pay this amount in cash, which they elected to do for 2011.

The number of any restricted common units granted to each non-employee manager is computed based on the date of the grant as determined by the compensation committee, rounded to the nearest unit. Cash distributions on any restricted common units are made at the time such distributions are made to other holders of common units.

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The following table sets forth a summary of the 2011 non-employee manager compensation, as determined by our board of managers:

	Manager Compensation			
Name	Fees Earned or Paid in Cash	Unit Awards	All Other Compensation [a]	Total
Richard H. Bachmann	$ 75,000	$	$ 75,000	$ 150,000
John R. Collins (b)	$ 21,630	$	$ 39,041	$ 60,671
Richard S. Langdon	$ 94,239	$	$ 75,000	$ 169,239
Hugh M. McIntosh (b)	$ 21,630	$	$ 39,041	$ 60,671
John N. Seitz	$ 75,000	$	$ 75,000	$ 150,000

(a) For 2011, due to the limited number of units remaining under our Long-Term Incentive Plan and our 2009 Omnibus Incentive Compensation Plan, instead of receiving an annual restricted common unit award of $75,000 to be paid in March 2012, each manager received a cash award of $75,000 to be paid in March 2012.

(b) Historically, the two Class A members of our board of managers did not receive compensation from us for serving as our managers. Beginning on August 24, 2011, the two Class A members of our board of managers now receive the same compensation package as our three independent managers.

In 2012, all managers will receive the same compensation package except that each is again to be paid $75,000 in cash on March 1, 2013, instead of being awarded restricted common units with a value of $75,000. In addition, each manager will be indemnified by us for actions associated with being a manager to the full extent permitted under Delaware law.

Compensation Committee Interlocks and Insider Participation

During 2011, none of our named executive officers served as a member of the board of directors or compensation committee of any entity that had one or more of its named executive officers serving as a member of our board of managers or compensation committee.

Compensation Committee Report

The compensation committee of the board of managers has reviewed and discussed the *Compensation Discussion and Analysis* with management. Based on such review and discussions, the compensation committee recommended to the board of managers that the *Compensation Discussion and Analysis* be included in this Form 10-K.

John N. Seitz, Chairman

Richard H. Bachmann

Richard S. Langdon

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

The following table sets forth the beneficial ownership of our units held by:

- each unitholder who is a beneficial owner of more than 5% of our outstanding units;
- each of our managers and named executive officers; and
- our managers and named executive officers as a group.

The amounts and percentage of common units and Class A units beneficially owned are reported on the basis of the SEC rules governing the determination of beneficial ownership of securities. Under the SEC rules, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, and/or investment power, which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

Percentage of total units beneficially owned is based on 23,712,857 common units and 483,936 Class A units outstanding. Except as indicated by footnote, to our knowledge the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable. The address of all of our managers and named executive officers is c/o Constellation Energy Partners LLC, 1801 Main Street, Houston, Texas 77002. Ownership amounts are as of February 29, 2012.

Name of Beneficial Owner	Common Units Beneficially Owned Number	Common Units Beneficially Owned Percentage	Class A Units Beneficially Owned Number	Class A Units Beneficially Owned Percentage	Percentage of Total Units Beneficially Owned Percentage
PostRock Energy Corporation[(1)]	5,918,894	24.9%	483,936	100%	26.4%
Volosin Adrian[(2)]	1,195,000	5.0%			14.9%
Essex Equity Capital Management, LLC[(3)]	2,168,312	9.1%			9.0%
Richard H. Bachmann	60,612	*			*
Stephen R. Brunner	712,400	3.0%			2.9%
John R. Collins					
Michael B. Hiney	105,985	*			*
Richard S. Langdon	40,100	*			*
Hugh M. McIntosh					
Lisa J. Mellencamp	188,300	*			*
John N. Seitz	51,612	*			*
Charles C. Ward	309,233	1.3%			1.3%
All managers and named executive officers as a group (9 persons)	1,468,242	6.2%			6.1%

* Less than 1%

(1) Ownership data as reported on Schedule 13D filed on December 20, 2011, by Constellation Energy Partners Management, LLC, PostRock Energy Corporation, White Deer Energy L.P., White Deer Energy TE L.P., White Deer Energy FI L.P., Edelman & Guill Energy L.P., Edelman & Guill Energy Ltd., Thomas J. Edelman, and Ben A. Guill. PostRock Energy Corporation, through its direct ownership of Constellation Energy Partners Management, LLC, may be deemed to beneficially own the Class B common units and Class A units held by Constellation Energy Partners Management, LLC. The address of PostRock Energy Corporation and Constellation Energy Partners Management, LLC is 210 Park Avenue, Oklahoma City, Oklahoma 73102. The address of the other entities reported is White Deer Energy L.P., 667 Madison Avenue, 4th fl., New York, NY 10065.

(2) Ownership data as reported on Schedule 13G filed on September 13, 2011 by Volosin Adrian and TOTUS s.r.o. The filing lists 415,000 Class B common units owned by Volosin Adrian and 780,000 Class B common units by TOTUS s.r.o., of which they have the sole power to vote, direct to vote, dispose of or direct the disposition of the units. The address of Volosin Adrian and TOTUS s.r.o is Dubovicka Roven 13, Lipany, 08271 Slovak Republic.

(3) Ownership data as reported on Schedule 13G filed on February 14, 2012, by Essex Equity Capital Management, LLC, Essex Equity Joint Investment Vehicle, LLC, Richmond Hill Investment Co., LP, Richmond Hill Capital Management, LLC, Richmond Hill Advisors, LLC, and Ryan P. Taylor. The address of Essex Equity Capital Management, LLC is 375 Hudson Street, 12th Floor, New York, New York 10014. The filing lists 2,020,896 Class B common units owned by Essex Equity Joint Investment Vehicle, LLC and 147,416 Class B common units owned by Richmond Hill Capital Partners, LP, of which they have sole voting power and shared voting power, respectively.

Equity Compensation Plan Information

The following table reflects our equity compensation plan information for our Long-Term Incentive Plan, our 2009 Omnibus Incentive Compensation Plan, and our Executive Inducement Bonus Program as of December 31, 2011:

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Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders (a)		$	357,746
Equity compensation plans not approved by security holders		$	
Total		$	357,746

(a) As of February 29, 2012, the number of securities remaining available for future issuance under our Long-Term Incentive Plan as was 124,728 and the number remaining available under our 2009 Omnibus Incentive Plan was 286,793.

Each of these unit-based compensation programs are further discussed in Item 11. Executive Compensation-*Compensation Discussion and Analysis.*

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

Both Constellation and PostRock, through subsidiaries, own a significant number of our units. As of December 31, 2011, CEPM, a subsidiary of PostRock, owns all of our Class A units and 5,918,894 Class B common units. Constellation Energy Partners Holdings, LLC, or CEPH, a subsidiary of Constellation, owns all of our Class C management incentive interests and all of our Class D interests. As discussed in Item 10. Managers, Executive Officers and Corporate Governance-*Committees of the Board of Managers Conflicts Committee* , either our board of managers or the board s conflicts committee reviews all related person transactions.

Our board of managers has established a conflicts committee to review specific matters that the board believes may involve conflicts of interest, including transactions with related persons such as Constellation, PostRock or their affiliates, including CEPH and CEPM. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to our company. Our limited liability company agreement provides that members of the conflicts committee may not be officers or employees of our company, or directors, officers or employees of any of our affiliates, and must meet the independence standards for service on an audit committee of a board of directors as established by NYSE Amex and SEC rules. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to our company and approved by all of our unitholders. For 2011, there were no related party transactions with Constellation, PostRock or their affiliates that were reviewed or required to be reviewed by the conflicts committee other than a partial review of the initial agreement between Constellation and PostRock regarding the sale of all of Constellation s interests in our Company to PostRock which was not consummated on the terms presented. Our board is not required by the terms of our limited liability company agreement to submit the resolution of a potential conflict of interest to the conflicts committee, and may itself resolve such conflict of interest if the board determines that (i) the terms of the related person transaction are no less favorable to us than those generally being provided to or available from unrelated third parties or (ii) the transaction is fair and reasonable to us, taking into account the totality of the relationships between the parties involved. Any matters approved by the board in this manner will be deemed approved by all of our unitholders.

Distributions and Payments to Constellation Entities

The following summarizes the distributions and payments made or to be made by us to Constellation and its subsidiaries, including CCG and CEPH, in connection with our ongoing operations and any liquidation of us. CEPM was acquired by PostRock in August 2011, and is no longer a subsidiary of Constellation.

Distributions of available cash to CEPH

We generally make any cash distributions 98% to common unitholders, including CEPH, a subsidiary of Constellation, until December 19, 2011, when it sold its remaining Class B common units to CEPM. During 2011 and 2010, CEPH received no distributions on the Class B common units that it owned. In addition, if distributions exceed the Target Distribution (as defined in our limited liability company agreement) and certain other requirements are met, CEPH will be entitled in respect of its Class C management incentive interests to 15% of distributions above the Target Distribution. None of these applicable requirements have been met, and, as a result, CEPH has not been entitled to receive any Class C management incentive interest distributions.

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Distributions to CEPH for Class D interests

CEPH holds all of our Class D interests. The Class D interests will remain outstanding until the liquidation of CEP, but CEPH will be entitled to a zero liquidation amount at that time.

Conversion of Class C management incentive interests

Generally, if the common unitholders vote to eliminate the special voting rights of the holder of our Class A units, the Class A units will be converted into Class B common units on a one-for-one basis, and CEPH will have the right to elect to convert its Class C management incentive interests into Class B common units at fair market value. Should CEPH s Class C management incentive interests convert into Class B common units, CEPH will receive any cash distributions on its Class B common units.

Liquidation

Upon our liquidation, the unitholders, including CEPH as the holder of the Class C management incentive interests and Class D interests that are then outstanding, will be entitled to receive liquidating distributions according to its respective capital account balances.

Omnibus Agreement

At the closing of our initial public offering in November 2006, we entered into an omnibus agreement with CCG, a subsidiary of Constellation. Under the omnibus agreement, CCG agreed to indemnify us against certain liabilities relating to:

- for a period of six years and 30 days after our initial public offering, any of our income tax liabilities, or any income tax liability attributable to our operation of our properties, in each case relating to periods prior to the closing of our initial public offering;
- legal actions pending against Constellation or us at the time of our initial public offering;
- events and conditions associated with the ownership by Constellation or its affiliates of the undivided mineral interest in certain of our properties in the Robinson s Bend Field for depths generally below 100 feet below the base of the lowest producing coal seam; and
- for a period of one year after our initial public offering, any miscalculation in the amount payable to the Trust in respect of the NPI for any period prior to the initial public offering, provided that (i) such miscalculation relates to amount(s) payable no more than four years prior to our initial public offering and (ii) the aggregate amount payable by CCG pursuant to this bullet point does not exceed $0.5 million.

We made a claim under the Omnibus Agreement to CCG as a result of the litigation with respect to the Torch NPI calculation for periods prior to our initial public offering. CCG has reimbursed us for one half of our legal costs associated with the Torch-related litigation and for one half of the $1.2 million settlement which was effective in June 2011.

Trademark License

In connection with our initial public offering, Constellation granted a limited license to us for the use of certain trademarks in connection with our business. The license will terminate upon the elimination of the right of the holder or holders of our Class A units to elect the Class A managers pursuant to our limited liability company agreement. The license did not terminate upon the sale by Constellation of our Class A units to PostRock. Constellation will indemnify us from any third-party claims alleging trademark infringement that may arise out of our use of the Constellation trademarks under the license. No amounts were paid under this agreement during 2011 or 2010.

PostRock-Related Announcement

On August 8, 2011, PostRock announced that it had acquired all of our Class A units and 3,128,670 of our Class B common units in a transaction with Constellation. As a result of the transaction, PostRock received the right to appoint two Class A managers to our board of managers. On December 19, 2011, PostRock acquired Constellation s remaining 2,790,224 Class B common units. The units acquired in these two transactions in aggregate represent a 26.4% interest in us as of December 31, 2011. Approval of these transactions was neither required nor given by our board of managers or conflicts committee. We believe PostRock is now an interested unitholder under Section 203 of the Delaware General Corporation Law. Section 203 as it applies to us prohibits an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in business combinations with us for three years following the

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time such person becomes an interested unitholder without the approval of our board of managers and the vote of 66 2/3% of our outstanding Class B common units, excluding those held by the interested unitholder. Section 203 broadly defines business combination to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. In addition to limiting our ability to enter into transactions with PostRock or its affiliates, this provision of our limited liability company agreement could have an anti-takeover effect with respect to transactions not approved in advance by our board of managers, including discouraging takeover attempts that might result in a premium over the market price for our common units.

Distributions and Payments to PostRock Entities

The following summarizes the distributions and payments made or to be made by us to PostRock and its subsidiaries, including CEPM, in connection with our ongoing operations and any liquidation of us. CEPM was a subsidiary of Constellation until August 2011, at which time it became a subsidiary of PostRock.

Distributions of available cash to CEPM

We generally make any cash distributions 98% to common unitholders, including CEPM, and 2% to CEPM in respect of its Class A units. During 2011 and 2010, CEPM received no distributions on its Class A units or on its Class B common units.

Conversion of Class A units

Generally, if the common unitholders vote to eliminate the special voting rights of the holder of our Class A units, the Class A units will be converted into Class B common units on a one-for-one basis. Should CEPM s Class A units convert into Class B common units, CEPM will receive any cash distributions on its Class B common units.

Liquidation

Upon our liquidation, the unitholders, including CEPM, as a common unitholder and as the holder of the Class A units that are then outstanding, will be entitled to receive liquidating distributions according to its respective capital account balances.

Board Independence

Refer to Item 10. Managers, Executive Officers and Corporate Governance for a discussion of our board of managers.

Item 14. Principal Accounting Fees and Services

We engaged our principal accountant, PricewaterhouseCoopers LLP, to audit our financial statements and perform other professional services for the fiscal years ended December 31, 2011 and 2010.

Audit Fees. The aggregate fees billed for the financial statement audit or services provided in connection with statutory or regulatory filings for the years ended 2011 and 2010 were $583,640 and $897,344, respectively.

Audit-Related Fees. The aggregate audit-related fees billed by PricewaterhouseCoopers LLP for the years ended 2011 and 2010 were $8,300 and $11,970, respectively. These fees related to consents for registration statements.

Tax Fees. The aggregate fees related to the preparation of K-1 statements for the years ended 2011 and 2010 were $449,052 and $684,728, respectively.

All Other Fees. The other fees billed by our principal accountant for the years ended 2011 and 2010 for services other than those described above were $23,000 and $7,500, respectively.

Audit Committee Pre-Approval Policies and Practices

Our audit committee must pre-approve any audit and permissible non-audit services performed by our independent registered public accounting firm. Additionally, the audit committee has oversight responsibility to ensure the independent registered public accounting firm is not engaged to perform certain enumerated non-audit services, including but not limited to bookkeeping, financial information system design and implementation, appraisal or valuation services, internal audit outsourcing services and legal services. The audit committee has adopted an audit and non-audit services pre-approval policy, which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent registered public accounting firm must be approved. Pursuant to the policy, all services must be reviewed and approved and the chairman of the audit committee has been delegated the authority to specifically pre-approve services, which pre-approval is subsequently reviewed with the committee.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as a part of this Annual Report on Form 10-K:

1. Financial Statements:

Reports of Independent Registered Public Accounting Firm dated February 29, 2012 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Income (Loss) Constellation Energy Partners LLC for the three years ended December 31, 2011

Consolidated Balance Sheets Constellation Energy Partners LLC at December 31, 2011 and December 31, 2010

Consolidated Statements of Cash Flows Constellation Energy Partners LLC for the three years ended December 31, 2011

Consolidated Statements of Changes in Members Equity Constellation Energy Partners LLC for the three years ended December 31, 2011

Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

Schedule II Valuation and Qualifying Accounts

Schedules other than Schedule II are omitted as not applicable or not required

3. Exhibits Required by Item 601 of Regulation S-K.

Exhibit Number	**Description**
2.1	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.2	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC, Kansas Production EQR, LLC and Kansas Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.3	Agreement of Merger, dated as of July 12, 2007, among AMVEST Osage, Inc., AMVEST Oil & Gas, Inc. and CEP Mid-Continent LLC, f/k/a CEP Cherokee Basin LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).
2.4	Purchase and Sale Agreement, dated as of August 2, 2007, between Newfield Exploration Mid-Continent Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).
2.5	Nominee Agreement, dated as of September 21, 2007, by and between Newfield Exploration Mid-Continent Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
2.6	Asset Purchase and Sale Agreement, dated as of May 12, 2005, by and among Everlast Energy LLC, RB Marketing Company LLC, Robinson s Bend Operating Company LLC and CBM Equity IV, LLC (incorporated herein by reference to Exhibit 10.9 to Amendment No. 2 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners

LLC on September 29, 2006.

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Exhibit Number	Description
2.7	Agreement for Purchase and Sale, dated as of February 19, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.8	First Amendment to Agreement for Purchase and Sale, dated as of March 31, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.9	Oil and Gas Purchase Contract, dated as of October 1, 1993, by and between Torch Energy Marketing, Inc. and Torch Royalty Company (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2 to the Registration Statement on Form S-1 filed by Constellation Energy Partners LLC on June 29, 2006, File No. 333-134995).
3.1	Certificate of Formation of Constellation Energy Partners LLC, as amended (incorporated herein by reference to Exhibit 3.1 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 12, 2007, File No. 001-33147).
3.2	Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
3.3	Amendment No. 1 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of April 23, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
3.4	Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of July 25, 2007. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).
3.5	Amendment No. 3 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of September 21, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).
3.6	Amendment No. 4 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of December 28, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on December 28, 2007, File No. 001-33147).
10.1	Omnibus Agreement, dated as of November 20, 2006, among Constellation Energy Partners LLC, Constellation Energy Commodities Group, Inc., Robinson s Bend Production II, LLC, Robinson s Bend Operating II, LLC and Robinson s Bend Marketing II, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
10.2	$350,000,000 Amended and Restated Credit Agreement, dated as of November 13, 2009, among Constellation Energy Partners LLC, as borrower, The Royal Bank of Scotland plc, as administrative agent, RBS Securities Inc., as joint lead arranger and sole book runner, The Bank of Nova Scotia, as joint lead arranger and co-syndication agent, BNP Paribas, as joint lead arranger and co-syndication agent, and the lenders party hereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 16, 2009, File No. 001-33147).
10.3	First Amendment to Amended and Restated Credit Agreement, dated as of February 11, 2010, by and among Constellation Energy Partners LLC and the lenders signatory thereto (incorporated herein by reference to Exhibit 10.7 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 25,2010, File No. 001-33147).
10.4	Second Amendment to Amended and Restated Credit Agreement, effective as of June 3, 2011, by and among Constellation Energy Partners LLC, the lenders signatory thereto and The Royal Bank of Scotland plc (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 3, 2011, File No. 001-33147).

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Exhibit Number	Description
10.5	Trademark License Agreement, dated as of November 20, 2006, by and among Constellation Energy Group, Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
10.6	Exploration and Development Agreement, dated July 25, 2005, by and between The Osage Nation and AMVEST Osage, Inc. (incorporated herein by reference to Exhibit 10.23 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.7	Substituted and Replaced First Amendment to the Exploration and Development Agreement, dated October 18, 2006, by and between The Osage Nation and AMVEST Osage, Inc. (incorporated herein by reference to Exhibit 10.24 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.8	Assignment, Assumption and Ratification Agreement, dated as of July 25, 2007, by and between AMVEST Osage, Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 10.25 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.9	Water Gathering and Disposal Agreement, dated as of August 9, 1990, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.17 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.10	First Amendment to Water Gathering and Disposal Agreement, dated as of October 1, 1993, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.18 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File NO. 001-33147).
10.11	Second Amendment to Water Gathering and Disposal Agreement, dated as of November 30, 2004, by and between Robinson s Bend Operating Company, LLC and Everlast Energy LLC (incorporated herein by reference to Exhibit 10.19 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File NO. 001-33147).
10.12	Third Amendment, dated June 13, 2011, to Water Gathering and Disposal Agreement dated November 30, 2004, by and between Robinson s Bend Operating II, LLC, Robinson s Bend Production II, LLC and Torch Energy Associates Ltd. (incorporated herein by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 15, 2011, File No. 001-33147).
10.13	Settlement and Release Agreement, effective as of June 13, 2011, by and among Trust Venture Company, LLC, Trust Acquisition Company, LLC, Wilmington Trust Company, Constellation Energy Partners LLC, Robinson s Bend Production II, LLC and Robinson s Bend Operating II, LLC (incorporated herein by reference to Exhibit 99.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 15, 2011, File No. 001-33147).
+10.14	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Stephen R. Brunner (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
+10.15	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Charles C. Ward (incorporated herein by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on November 6, 2009, File No. 001-33147).
+10.16	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Lisa J. Mellencamp (incorporated herein by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on November 6, 2009, File No. 001-33147).
+10.17	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Michael B. Hiney (incorporated herein by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on November 6, 2009, File No. 001-33147).

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Exhibit Number	Description
+10.18	Constellation Energy Partners LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 20, 2006, File No. 001-33147).
+10.19	Constellation Energy Partners LLC 2009 Omnibus Incentive Compensation Plan (incorporated herein by reference to Exhibit A to the Proxy Statement filed by Constellation Energy Partners LLC on October 22, 2009, File No. 001-33147).
+10.20	Form of Grant Agreement Relating to Notional Units with DERs Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.9 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 4, 2009, File No. 001-33147).
+10.21	Form of Grant Agreement Relating to Notional Units with DERs Independent Managers (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.10 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 4, 2009, File No. 001-33147).
+10.22	Form of Grant Agreement Relating to Restricted Units Executives (under the 2009 Omnibus Incentive Compensation Plan incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on March 3, 2010, File No. 001-33147).
+10.23	Form of Amended and Restated Grant Agreement Relating to Unit-Based Awards Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on August 5, 2011, File No. 001-33147).
+10.24	Form of Grant Agreement Relating to Restricted Units Independent Managers (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.30 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 25, 2010, File No. 001-33147).
*12.1	Computation of Ratio of Earnings to Fixed Charges.
*21.1	List of subsidiaries of Constellation Energy Partners LLC.
*23.1	Consent of PricewaterhouseCoopers LLP.
*23.2	Consent of Netherland, Sewell & Associates, Inc.
*31.1	Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	Report of Netherland, Sewell & Associates, Inc.
**101.INS	XRBL Instance Document
**101.SCH	XRBL Schema Document
**101.CAL	XRBL Calculation Linkbase Document
**101.LAB	XRBL Label Linkbase Document

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Exhibit Number	Description
**101.PRE	XRBL Presentation Linkbase Document
**101.DEF	XRBL Definition Linkbase Document

* Filed herewith
\+ Management contract or compensatory plan or arrangement.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders and Board of Managers of Constellation Energy Partners LLC:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations and comprehensive income (loss), of cash flows, and of changes in members equity present fairly, in all material respects, the financial position of Constellation Energy Partners LLC and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 29, 2012

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Income (Loss)

	For the year ended December 31, 2011	For the year ended December 31, 2010	For the year ended December 31, 2009
		(In 000 s except unit data)	
Revenues			
Natural gas sales	$ 133,769	$ 103,997	$ 118,580
Oil and liquid sales	10,870	4,695	4,546
Gain / (Loss) from mark-to-market activities (see Note 3)	(39,422)	42,081	19,410
Total revenues	105,217	150,773	142,536
Expenses:			
Operating expenses:			
Lease operating expenses	27,949	30,798	33,535
Cost of sales	2,188	2,473	2,638
Production taxes	2,897	3,179	3,153
General and administrative	16,599	20,351	18,506
Exploration costs	131	760	855
(Gain) / Loss on sale of assets	19	(18)	
Depreciation, depletion and amortization	22,139	85,263	71,173
Asset impairments (see Note 5)	2,935	272,487	5,113
Accretion expense	907	822	406
Total operating expenses	75,764	416,115	135,379
Other expense / (income)			
Interest expense	8,886	12,721	11,967
Interest expense (Gain)/Loss from mark-to-market activities (see Note 3)	1,232	(765)	4,338
Interest (income)	(2)	(3)	(2)
Other expense (income)	(249)	(385)	(123)
Total other expenses / (income)	9,867	11,568	16,180
Total expenses	85,631	427,683	151,559
Net income (loss)	$ 19,586	$ (276,910)	$ (9,023)
Other comprehensive income (loss)	(5,483)	(17,447)	(21,760)
Comprehensive income (loss)	$ 14,103	$ (294,357)	$ (30,783)
Earnings per unit (see Note 1)			
Earnings (loss) per unit Basic	$ 0.81	$ (11.36)	$ (0.40)
Units outstanding Basic	24,273,491	24,370,545	22,664,895
Earnings (loss) per unit Diluted	$ 0.81	$ (11.36)	$ (0.40)
Units outstanding Diluted	24,273,491	24,370,545	22,664,895
Distributions declared and paid per unit	$	$	$ 0.26

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

	December 31, 2011	December 31, 2010
	(In 000 s)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 17,176	$ 7,892
Accounts receivable	6,394	7,371
Prepaid expenses	1,243	1,315
Risk management assets (see Note 3)	20,283	36,513
Total current assets	45,096	53,091
Oil and natural gas properties (See Note 5)		
Oil and natural gas properties, equipment and facilities	787,322	774,060
Material and supplies	1,243	2,073
Less accumulated depreciation, depletion, amortization, and impairments	(522,480)	(499,214)
Net oil and natural gas properties	266,085	276,919
Other assets		
Debt issue costs (net of accumulated amortization of $6,465 at December 31, 2011 and $4,888 at December 31, 2010)	2,423	3,727
Risk management assets (see Note 3)	17,603	46,986
Other non-current assets	3,099	3,654
Total assets	$ 334,306	$ 384,377
LIABILITIES AND MEMBERS EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 1,404	$ 1,418
Accrued liabilities	10,638	10,369
Royalty payable	2,134	2,605
Risk management liabilities (see Note 3)	378	141
Total current liabilities	14,554	14,533
Other liabilities		
Asset retirement obligation	14,047	13,024
Risk management liabilities (see Note 3)	286	
Other non-current liabilities	99	
Debt	98,400	165,000
Total other liabilities	112,832	178,024
Total liabilities	127,386	192,557
Commitments and contingencies (See Note 8)		
Class D Interests		6,667
Members equity		
Class A units, 485,033 and 487,750 shares authorized, issued and outstanding, respectively	4,030	3,485
Class B units, 24,124,378 and 24,298,763 shares authorized, respectively, and 23,766,632 and 23,899,758 issued and outstanding, respectively	197,453	170,748
Accumulated other comprehensive income	5,437	10,920

Total members equity	206,920	185,153
Total liabilities and members equity	$ 334, 306	$ 384,377

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Cash Flows

	For the year ended December 31, 2011	For the year ended December 31, 2010	For the year ended December 31, 2009
		(In 000 s)	
Cash flows from operating activities:			
Net income (loss)	$ 19,586	$ (276,910)	$ (9,023)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	22,139	85,263	71,173
Asset impairments (see Note 5)	1,935	272,487	5,113
Amortization of debt issuance costs	1,577	1,964	1,429
Accretion expense	907	822	406
Equity (earnings) losses in affiliate	(286)	(385)	(125)
(Gain) Loss from disposition of property and equipment	19	(18)	
Bad debt expense	12	69	
Dryhole costs		61	173
Hedge ineffectiveness			267
(Gain) Loss from mark-to-market activities	40,654	(42,846)	(15,072)
Unit-based compensation programs	1,341	1,849	1,308
Changes in Assets and Liabilities:			
Change in net risk management assets and liabilities	(1)	(1)	420
(Increase) decrease in accounts receivable	965	939	984
(Increase) decrease in prepaid expenses	118	(15)	(275)
(Increase) decrease in other assets	1,050	1	33
Increase (decrease) in accounts payable	(14)	316	(1,707)
Increase (decrease) in payable to affiliate		(201)	(842)
Increase (decrease) in accrued liabilities	(1,940)	(424)	2,203
Increase (decrease) in royalty payable	(471)	(2,142)	(378)
Increase (decrease) in other liabilities	99		
Net cash provided by operating activities	87,690	40,829	56,087
Cash flows from investing activities:			
Cash paid for acquisitions, net of cash acquired	(350)	(6,369)	(291)
Development of natural gas properties	(10,967)	(7,973)	(22,913)
Proceeds from sale of equipment	139	91	130
Distributions from equity affiliate	465	485	503
Net cash used in investing activities	(10,713)	(13,766)	(22,571)
Cash flows from financing activities:			
Members distributions			(5,820)
Proceeds from issuance of debt			37,500
Repayment of debt	(66,600)	(30,000)	(55,000)
Units tendered by employees for tax withholdings	(344)	(376)	(6)
Equity issue costs	(46)	(2)	(82)
Debt issue costs	(703)	(130)	(5,026)
Net cash (used in) provided by financing activities	(67,693)	(30,508)	(28,434)

Net (decrease) increase in cash	9,284	(3,445)	5,082
Cash and cash equivalents, beginning of period	7,892	11,337	6,255
Cash and cash equivalents, end of period	$ 17,176	$ 7,892	$ 11,337
Supplemental disclosures of cash flow information:			
Change in accrued capital expenditures	$ 1,720	$ 523	$ (2,760)
Cash received during the period for interest	$ 2	$ 3	$ 2
Cash paid during the period for interest	$ (5,101)	$ (7,106)	$ (6,225)
Cash paid during the period for income taxes	$ (37)	$ (2)	$ (2)

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Changes in Members Equity

	Class A		Class B		Accumulated Other Comprehensive Income	Total Members Equity
	Units	Amount	Units	Amount		
			(In 000 s, except unit data)			
Balance, December 31, 2008	447,721	$ 9,265	21,938,342	$ 454,030	$ 50,127	$ 513,422
Distributions		(116)		(5,704)		(5,820)
Equity Issuance Cost		(2)		(82)		(84)
Units tendered by employees for tax withholding	(37)	(0)	(1,792)	(6)		(6)
Change in fair value of commodity hedges					17,694	17,694
Cash settlement of commodity hedges					(46,730)	(46,730)
Change in fair value of interest rate hedges					7,276	7,276
Unit-based compensation programs	29,266	26	1,439,586	1,282		1,308
Net income (loss)		(180)		(8,843)		(9,023)
Balance, December 31, 2009	476,950	$ 8,993	23,376,136	$ 440,677	$ 28,367	$ 478,037
Distributions						
Units tendered by employees for tax withholding	(1,885)	(8)	(92,353)	(368)		(376)
Change in fair value of commodity hedges					(495)	(495)
Cash settlement of commodity hedges					(17,341)	(17,341)
Cash settlement of interest rate hedges					389	389
Unit-based compensation programs	12,685	37	615,975	1,812		1,849
Net income (loss)		(5,538)		(271,372)		(276,910)
Balance, December 31, 2010	487,750	$ 3,484	23,899,758	$ 170,749	$ 10,920	$ 185,153
Distributions						
Units tendered by employees for tax withholding	(2,448)	(7)	(119,963)	(337)		(344)
Change in fair value of commodity hedges					232	232
Cash settlement of commodity hedges					(5,715)	(5,715)
Class D liquidation		134		6,533		6,667
Unit-based compensation programs	(269)	27	(13,163)	1,314		1,341
Net income (loss)		392		19,194		19,586
Balance, December 31, 2011	485,033	$ 4,030	23,766,632	$ 197,453	$ 5,437	$ 206,920

See accompanying notes to consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2011, 2010 and 2009

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Basis of Presentation

Constellation Energy Partners LLC (CEP , we , us , our or the Company) was organized as a limited liability company on February 7, 2005, u the laws of the State of Delaware. We completed our initial public offering on November 20, 2006, and currently trade on the NYSE Amex LLC (NYSE Amex) under the symbol CEP . Both Constellation Energy Group, Inc. (NYSE: CEG) (Constellation or CEG) and PostRock Energy Corporation (NASDAQ: PSTR) (PostRock), through subsidiaries, own a significant number of our units. As of December 31, 2011, Constellation Energy Partners Management, LLC (CEPM), a subsidiary of PostRock, owns all 485,033 of our Class A units and 5,918,894 of our Class B common units. Constellation Energy Partners Holdings, LLC, or CEPH, a subsidiary of Constellation, owns all of our Class C management incentive interests and all of our Class D interests.

We are currently focused on the development and acquisition of natural gas properties in the Black Warrior Basin in Alabama, the Cherokee Basin in Kansas and Oklahoma, the Woodford Shale in Oklahoma, and the Central Kansas Uplift in Kansas and Nebraska.

Accounting policies used by us conform to accounting principles generally accepted in the United States of America. The accompanying financial statements include the accounts of us and our wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. We operate our oil and natural gas properties as one business segment: the exploration, development and production of oil and natural gas. Our management evaluates performance based on one business segment as there are not different economic environments within the operation of our oil and natural gas properties.

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash equivalents. Checks-in-transit were $1.8 million in 2011 and $1.6 million in 2010 and are included in accounts payable in our consolidated balance sheets.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject us to a concentration of credit risk consist of cash and cash equivalents, accounts receivable and derivative financial instruments. We place our cash with high credit quality financial institutions. We place our derivative financial instruments with financial institutions that participate in our reserve-based credit facility and maintain an investment grade credit rating. Substantially all of our accounts receivables are due from purchasers of oil and natural gas. These sales are generally unsecured and, in some cases, may carry a parent guarantee. As we generally have fewer than 10 large customers for our oil and natural gas sales, we routinely assess the financial strength of our customers. Bad debt expense is recognized on an account-by-account review and when recovery is not probable. Our allowance for doubtful accounts was less than $0.1 million in 2011, less than $0.1 million in 2010 and none in 2009. We have no off-balance-sheet credit exposure related to our operations or customers.

For the year ended December 31, 2011, five customers accounted for approximately 28%, 17%, 7%, 5% and 5% of our sales revenues. For the year ended December 31, 2010, five customers accounted for approximately 30%, 17%, 9%, 6% and 5% of our sales revenues. For the year ended December 31, 2009, five customers accounted for approximately 31%, 10%, 10%, 9% and 6% of our sales revenues.

Oil and Natural Gas Properties

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for our oil and natural gas exploration, development and production activities. Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

Effective for fiscal years ending on or after December 31, 2009, new accounting rules require that we price our future oil and natural gas production at the preceding twelve-month average of the first-day-of-the-month reference prices as

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adjusted for location and quality differentials. Prior to the new rules, we were required to price our future oil and natural gas production at an SEC-required price which is based on the oil and natural gas prices in effect at the end of each fiscal quarter. Such SEC-required prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Our proved reserve estimates exclude the effect of any derivatives we have in place.

Depreciation and depletion of producing oil and natural gas properties is recorded at the field level, based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs (including wells and related equipment and facilities) are amortized on the basis of proved developed reserves. It has been our historical practice to use our year-end reserve report to adjust our depreciation, depletion, and amortization expense for the fourth quarter. Prior to the fourth quarter 2009, depreciation, depletion, and amortization expense was calculated using year-end reserve reports based on year-end pricing, however for the fourth quarter 2009 the SEC-required price was used to calculate depreciation, depletion, and amortization expense. As more fully described in Note 15, proved reserves estimates are subject to future revisions when additional information becomes available.

As described in Note 9, estimated asset retirement costs are recognized when the asset is acquired or placed in service, and are amortized over proved developed reserves using the units-of-production method. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

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

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. The cash flow estimates are based upon third party reserve reports using future expected oil and natural gas prices adjusted for basis differentials. Cash flow estimates for the impairment testing exclude derivative instruments. Refer to Note 5 for additional information.

Unproven properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred. Impairment is deemed to have occurred if a lease is going to expire prior to any planned drilling on the leased property.

Property acquisition costs are capitalized when incurred.

Support Equipment and Facilities

Support equipment and facilities consist of certain of our water treatment facilities, gathering lines, roads, pipelines, and other various support equipment. Items are capitalized when acquired and depreciated using the straight-line method over the useful life of the assets.

Materials and Supplies

Materials and supplies consist of well equipment, parts and supplies. They are valued at the lower of cost or market, using either the specific identification or first-in first-out method, depending on the inventory type. Materials and supplies are capitalized as used in the development or support of our oil and natural gas properties.

Depreciation, depletion and amortization of oil and natural gas properties was computed using the units-of-production method based on estimated proved reserves.

Oil and Natural Gas Reserve Quantities

Our estimate of proved reserves was based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Proved reserves were calculated based on various factors, including consideration of an independent reserve engineers report on proved reserves and an economic evaluation of all of our properties on a well-by-well basis. The process used to complete the estimates of proved reserves at December 31, 2011, 2010 and 2009 is described in detail in Note 15.

Reserves and their relation to estimated future net cash flows impact depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The accuracy of reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Proved reserve estimates were a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Derivatives and Hedging Activities

We use derivative financial instruments to achieve a more predictable cash flow from our oil and natural gas production by reducing our exposure to price fluctuations. Additionally, we use derivative financial instruments in the form of interest rate swaps to mitigate interest rate exposure on our borrowings under our reserve-based credit facility.

We account for all our open derivatives as mark-to-market activities. All derivative instruments are recorded in the consolidated balance sheet as either an asset or a liability measured at fair value with changes in fair value recognized in earnings. All of our open derivatives are effective as economic hedges of our commodity price or interest rate exposure. These contracts are accounted for using the mark-to-market accounting method. Using this method, the contracts are carried at their fair value on our consolidated balance sheets under the captions Risk management assets and Risk management liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statements of operations and comprehensive income (loss) under the caption Gain (loss) from mark-to-market activities. We record settled oil or natural gas swaps as Oil and liquid sales or Natural gas sales and settled interest rate swaps as Interest expense.

Revenue Recognition

Sales of oil and natural gas are recognized when oil or natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale are reasonably assured and the sales price is fixed or determinable. Oil and natural gas is sold on a monthly basis. Most of our sales contracts pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil or natural gas, and prevailing supply and demand conditions, so that the price of the oil or natural gas fluctuates to remain competitive with other available energy supplies. As a result, revenues from the sale of oil and natural gas will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our oil and natural gas contracts are customary in the industry.

Gas imbalances occur when sales are more or less than the entitled ownership percentage of total gas production. We use the entitlements method when accounting for gas imbalances. Any amount received in excess is treated as a liability. If less than the entitled share of the production is received, the excess is recorded as a receivable. There were no gas imbalance positions at December 31, 2011, 2010, or 2009.

Income Taxes

CEP and each of its wholly-owned subsidiary LLCs are treated as a partnership for federal and state income tax purposes. Essentially all of our taxable income or loss, which may differ considerably from net income or loss reported for financial reporting purposes, is passed through to the federal income tax returns of its members. As such, no federal income tax for these entities has been provided for in the accompanying financial statements. CEP is subject to franchise tax obligations in Kansas and Texas and state tax obligations in Alabama, Oklahoma, and Nebraska. CEP also has informational filing requirements in Georgia, Indiana, Maine, Missouri, New Jersey, New York, Oregon, Pennsylvania, and West Virginia because we have resident unitholders in these states.

Our wholly-owned subsidiary, CEP Services Company, Inc. is a taxable entity. For the years ended December 31, 2011, and 2010, the current federal and state tax liability for the entity was less than $0.1 million and $0.1 million, respectively. The entity has no deferred tax assets or liabilities. Taxes are paid to the IRS or the applicable states in quarterly installments.

Use of Estimates

Estimates and assumptions are made when preparing financial statements under accounting principles generally accepted in the United States of America. These estimates and assumptions affect various matters, including:

- reported amounts of revenue and expenses in the Consolidated Statements of Operations and Other Comprehensive Income (Loss) during the reported periods,

reported amounts of assets and liabilities in the Consolidated Balance Sheets at the dates of the financial statements,

disclosure of quantities of reserves and use of those reserve quantities for depreciation, depletion and amortization, and

disclosure of contingent assets and liabilities at the date of the financial statements.

These estimates involve judgments with respect to numerous factors that are difficult to predict and are beyond management s control. As a result, actual amounts could materially differ from these estimates.

Earnings per Unit

Basic earnings per unit (EPU) are computed by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. At December 31, 2011, we had 485,033 Class A units and 23,766,632 Class B common units outstanding. Of the Class B common units, 1,112,150 units are restricted unvested common units granted and outstanding.

The following table presents earnings per common unit amounts:

Year ended December 31, 2011	Income (loss)	Units	Per Unit Amount
	(In 000 s except unit data)		
Basic EPU:			
Income (loss) allocable to unitholders	$ 19,586	24,273,491	$ 0.81
Diluted EPU:			
Income (loss) allocable to unitholders	$ 19,586	24,273,491	$ 0.81

Year ended December 31, 2010	Income (loss)	Units	Per Unit Amount
	(In 000 s except unit data)		
Basic EPU:			
Income (loss) allocable to unitholders	$ (276,910)	24,370,545	$ (11.36)
Diluted EPU:			
Income (loss) allocable to unitholders	$ (276,910)	24,370,545	$ (11.36)

Year ended December 31, 2009	Income (loss)	Units	Per Unit Amount
	(In 000 s except unit data)		
Basic EPU:			
Income (loss) allocable to unitholders	$ (9,023)	22,664,895	$ (0.40)
Diluted EPU:			
Income (loss) allocable to unitholders	$ (9,023)	22,664,895	$ (0.40)

Comprehensive Income (Loss)

Comprehensive income (loss) includes net earnings (loss) as well as unrealized gains and losses on derivative instruments that were previously accounted for as cash flow hedges.

Environmental Cost

We record environmental liabilities at their undiscounted amounts on our balance sheets in other current and long-term liabilities when our environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies clean-up experience and data released by the Federal Environmental Protection Agency (EPA) or other organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and we recognize a current period charge in operation and maintenance expense when clean-up efforts do not benefit future periods.

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Unit-Based Compensation

We record compensation expense for all equity grants issued under the Long-Term Incentive Program and the 2009 Omnibus Incentive Compensation Plan based on the fair value at the grant date, recognized over the vesting period.

Other Contingencies

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against the associated reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

Recent Accounting Pronouncements and Accounting Changes

In June 2011, the FASB issued ASU 2011-05, *Comprehensive Income (Topic 220)* that requires entities to present net income and other comprehensive income in either a single continuous statement or in two separate, but consecutive, statements of net income and other comprehensive income. The option to present items of other comprehensive income in the statement of changes in equity is eliminated. In December 2011, the FASB issued new authoritative accounting guidance which effectively deferred the requirement to present the reclassification adjustments on the face of the financial statements. The amended guidance is effective for us in the first quarter of 2012 and will not have any material impact on our financial statements or our disclosures.

In May 2011, the FASB issued ASU 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs*, and the IASB issued IFRS 13, *Fair Value Measurement* (together, the new guidance). The new guidance results in a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between U.S. GAAP and IFRS. The new guidance changes some fair value measurement principles and disclosure requirements. and is effective for interim and annual periods beginning on or after December 15, 2011. The amended guidance is effective for us in the first quarter of 2012 and we do not believe that this guidance will have any material impact on our financial statements or our disclosures.

2. ACQUISITIONS

Central Kansas Uplift Non-Operated Acquisition

On December 21, 2010, we acquired from a private seller, effective November 1, 2010, non-operated oil properties in the Central Kansas Uplift in northern Kansas and southern Nebraska for an all cash purchase price of approximately $5.6 million, including $0.3 million in post-closing adjustments received in 2011. At the acquisition, the properties produced approximately 126 barrels of oil equivalent per day from 36 wells. The operator of the properties is Murfin Drilling Company, Inc. Proved oil reserves were estimated to be 0.8 Bcfe, of which approximately 81% were classified as proved developed producing. The acquisition was funded with cash on hand. Our results of operations include the results of the non-operated wells after the date of acquisition.

The total consideration paid was $5.6 million, which consisted of $5.6 million in cash and assumed liabilities of less than $0.1 million, primarily associated with asset retirement obligations on the properties. The following table summarizes the allocation of the purchase price to the assets acquired and liabilities assumed at the date of acquisition.

Acquired December 21, 2010	**(in millions)**
Oil and Natural Gas Properties	$ 5.6
Total assets acquired	5.6
Asset retirement obligations	(0.0)
Net assets acquired	$ 5.6

The purchase price allocation is based on fair value evaluations of proved oil and natural gas reserves, discounted cash flows, quoted market prices, and other estimates by management.

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3. DERIVATIVE AND FINANCIAL INSTRUMENTS

Mark-to-Market Activities

We have hedged a portion of our expected natural gas and oil sales from currently producing wells through December 2015 and entered into hedging arrangements in the form of interest rate swaps to reduce the impact of volatility stemming from changes in the London interbank offered rate (LIBOR) on $93.0 million of our outstanding debt for various maturities extending through November 2014. All of our derivatives were accounted for as mark-to-market activities as of December 31, 2011.

For 2011 and 2010, we recognized mark-to-market losses of approximately $39.4 million and mark-to-market gains of approximately $42.1 million, respectively, in connection with our oil and natural gas commodity derivatives. For the year ended December 31, 2011 and 2010, we recognized a mark-to-market loss of approximately $2.1 million and a loss of approximately $0.8 million, respectively, in connection with our interest rate derivatives. At December 31, 2011 and December 31, 2010, the fair value of our derivatives accounted for as mark-to-market activities amounted to a net asset of approximately $37.2 million and a net asset of approximately $83.4 million, respectively.

Accumulated Other Comprehensive Income

Prior to the first quarter of 2009, we accounted for certain of our commodity and interest rate derivatives as hedging activities. The value of the cash flow hedges included in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets was an unrecognized gain of approximately $5.4 million and an unrecognized gain of $10.9 million at December 31, 2011 and December 31, 2010, respectively. We expect that the unrecognized gain will be reclassified from accumulated other comprehensive income (loss) (AOCI) to the income statement in the following periods:

For the Quarter Ended	Commodity Derivatives	Non-performance Risk	Total AOCI
March 31, 2012	718	(22)	696
June 30, 2012	1,928	(66)	1,862
September 30, 2012	1,721	(63)	1,658
December 31, 2012	1,271	(50)	1,221
Total	$ 5,638	$ (201)	$ 5,437

Hedge Restructuring

During the second quarter of 2011, we amended our existing NYMEX swap agreements to reset the NYMEX fixed-for-floating price to $5.75 per MMBtu for our natural gas production from January 2012 through December 2014. In conjunction with the transaction, we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million, which increased our reported operating cash flows. For tax purposes, the one-time cash payment from our swap counterparties will be amortized over the remaining life of the NYMEX contracts in accordance with the timing of the actual settlement of delivery of natural gas per the swap agreements.

Fair Value Measurements

We measure fair value of our financial and non-financial assets and liabilities on a recurring basis. Accounting standards define fair value, establish a framework for measuring fair value and require certain disclosures about fair value measurements for assets and liabilities measured on a recurring basis. All of our derivative instruments are recorded at fair value in our financial statements. Fair value is the exit price that we would receive to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date.

The following hierarchy prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices available in active markets for identical assets or liabilities as of the reporting date.

Level 2 Pricing inputs other than quoted prices in active markets included in Level 1 which are either directly or indirectly observable as of the reporting date. Level 2 consists primarily of non-exchange traded oil and natural gas commodity derivatives and interest rate derivatives.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. As of December 31, 2011, all of our derivatives were classified as Level 2. The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2 or Level 3. We prioritize the use of the highest level inputs available in determining fair value.

Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. Because of the long-term nature of certain assets and liabilities measured at fair value as well as differences in the availability of market prices and market liquidity over their terms, inputs for some assets and liabilities may fall into any one of the three levels in the fair value hierarchy. While we are required to classify these assets and liabilities in the lowest level in the hierarchy for which inputs are significant to the fair value measurement, a portion of that measurement may be determined using inputs from a higher level in the hierarchy.

The following tables set forth by level within the fair value hierarchy our assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2011 and December 31, 2010.

At December 31, 2011	**Level 1**	**Level 2**	**Level 3**	**Netting and Cash Collateral***	**Total Fair Value**
			(In 000	**s)**	
Risk management assets	$	$ 37,886	$	$	$ 37,886
Risk management liabilities		(664)			(664)
Total	$	$ 37,222	$	$	$ 37,222

* *We currently use our reserve-based credit facility to provide credit support for our derivative transactions and therefore we do not post cash collateral with our counterparties.*

At December 31, 2010	**Level 1**	**Level 2**	**Level 3**	**Netting and Cash Collateral***	**Total Fair Value**
			(In 000	**s)**	
Risk management assets	$	$ 83,499	$	$	$ 83,499
Risk management liabilities		(141)			(141)
Total	$	$ 83,358	$	$	$ 83,358

* *We currently use our reserve-based credit facility to provide credit support for our derivative transactions and therefore we do not post cash collateral with our counterparties.*

Risk management assets and liabilities in the table above represent the current fair value of all open derivative positions. We classify all of our derivative instruments as Risk management assets or Risk management liabilities in our Consolidated Balance Sheets. In order to conform with the current period presentation, we have reclassified our interest rate derivatives of approximately $3.6 million at December 31, 2010 from Level 3 to Level 2.

We use observable market data or information derived from observable market data in order to determine the fair value amounts presented above. We currently use our reserve-based credit facility to provide credit support for our derivative transactions. As a result, we do not post cash collateral with our counterparties, and have minimal non-performance credit risk on our liabilities with counterparties. We utilize observable market data for credit default swaps to assess the impact of non-performance credit risk when evaluating our net assets from counterparties. At December 31, 2011, the impact of non-performance credit risk on the valuation of our assets from counterparties was $1.0

million, of which $0.8 million was reflected as a decrease to our non-cash market-to-market gain and $0.2 million was reflected as a reduction to our accumulated other comprehensive income. At December 31, 2010, the impact of non-performance credit risk on the valuation of our assets from counterparties was $1.9 million, of which $1.4 million was reflected as a decrease to our non-cash market-to-market gain and $0.5 million was reflected as a reduction to our accumulated other comprehensive income.

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Fair Value of Financial Instruments

At December 31, 2011, the carrying values of cash and cash equivalents, accounts receivable, other current assets and current liabilities on the Consolidated Balance Sheets approximate fair value because of their short term nature. We believe the carrying value of long-term debt approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms, which represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties.

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The following fair value disclosures are applicable to our financial statements as of December 31, 2011, and 2010:

Derivative Type	Location of Asset/ (Liability) on Balance Sheet for Derivatives	Fair Value of Asset/ (Liability) on Balance Sheet (in 000 s) Year Ended December 31, 2011	Year Ended December 31, 2010
Commodity-MTM	Risk management assets-current	$ 27,208	$ 38,945
Commodity-MTM	Risk management assets-non-current	23,732	60,324
Commodity-MTM	Risk management assets-current	(6,925)	(2,432)
Commodity-MTM	Risk management assets-non-current	$ (1,325)	$ (9,765)
Commodity-MTM	Risk management liabilities-current	(664)	(141)
Interest Rate-MTM	Risk management assets-non-current	(4,804)	(3,573)
	Total Derivatives	$ 37,222	$ 83,358

Derivative Type	Location of Gain/(Loss) Recognized in Income for Derivatives	Amount of Gain/(Loss) in Income (in 000 s) Quarter Ended December 31, 2011	Quarter Ended December 31, 2010
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ 8,524	$ (10,464)
Commodity-MTM	Natural gas sales	9,666	7,978
Commodity-MTM	Oil and liquids sales	321	
Interest Rate-MTM	Interest expense-Gain/(Loss) from mark-to-market activities	(602)	1,939
Interest Rate-MTM	Interest expense	(535)	(631)
	Total	$ 17,374	$ (1,178)

Derivative Type	Location of Gain/(Loss) Recognized in Income for Derivatives	Amount of Gain/(Loss) in Income (in 000 s) Year Ended December 31, 2011	Year Ended December 31, 2010
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ (39,422)	$ 41,368
Commodity-MTM	Natural gas sales	76,367	$ 23,011
Commodity-MTM	Oil and liquids sales	605	$
Interest Rate-MTM	Interest expense-Gain/(Loss) from mark-to-market activities	(1,232)	765
Interest Rate-MTM	Interest expense	(2,131)	(3,454)
	Total	$ 34,187	$ 61,690

Derivative Type	Location of Gain / (Loss) Recognized in Income for Derivatives	Amount of Gain /(Loss) Reclassified from AOCI into Income (in 000 s) Quarter Ended December 31, 2011	Quarter Ended December 31, 2010

Commodity-Cash Flow	Gain/(Loss) from mark-to-market activities	$		$	713
Commodity-Cash Flow	Natural gas sales		1,283		3,568
Interest Rate-Cash Flow	Interest expense				
	Total	$	1,283	$	4,281

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Derivative Type	Location of Gain / (Loss) Recognized in Income for Derivatives	Amount of Gain /(Loss) Reclassified from AOCI into Income (in 000 s) Year Ended December 31, 2011	Year Ended December 31, 2010
Commodity-Cash Flow	Gain/(Loss) from mark-to-market activities	$	$ 713
Commodity-Cash Flow	Natural gas sales	5,715	17,341
Interest Rate-Cash Flow	Interest expense		(389)
	Total	$ 5,715	$ 17,665

As of December 31, 2011, we have interest rate swaps on $93.0 million of outstanding debt for various maturities extending through November 2014, various commodity swaps for 23,555,000 MMbtu of natural gas production through December 2014, various basis swaps for 16,606,526 MMbtu of natural gas production in the Cherokee Basin through December 2014, and commodity swaps for 215,138 Bbls of oil production through December 2015.

4. DEBT

Reserve-Based Credit Facility

On June 3, 2011, we executed a second amendment to our $350.0 million reserve-based credit facility with The Royal Bank of Scotland plc as administrative agent and a syndicate of lenders extending its maturity date to November 13, 2013. Borrowings under the reserve-based credit facility are secured by various mortgages of oil and natural gas properties that we and certain of our subsidiaries own as well as various security and pledge agreements among us and certain of our subsidiaries and the administrative agent. The current lenders and their percentage commitments in the reserve-based credit facility are The Royal Bank of Scotland plc (26.84%), BNP Paribas (21.95%), The Bank of Nova Scotia (21.95%), Societe Generale (14.63%), and ING Capital LLC (14.63%). See Note 17 for additional information.

The amount available for borrowing at any one time under the reserve-based credit facility is limited to the borrowing base for our oil and natural gas properties. As of December 31, 2011, our borrowing base was $125.0 million. The borrowing base is redetermined semi-annually, and may be redetermined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas prices prevailing at such time. Our next semi-annual borrowing base redetermination is scheduled during the second quarter of 2012. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders.

Borrowings under the reserve-based credit facility are available for acquisition, exploration, operation and maintenance of oil and natural gas properties, payment of expenses incurred in connection with the reserve-based credit facility, working capital and general limited liability company purposes. The reserve-based credit facility has a sub-limit of $20.0 million which may be used for the issuance of letters of credit. As of December 31, 2011, no letters of credit are outstanding.

At our election, interest for borrowings are determined by reference to (i) the London interbank rate, or LIBOR, plus an applicable margin between 2.50% and 3.50% per annum based on utilization or (ii) a domestic bank rate (ABR) plus an applicable margin between 1.50% and 2.50% per annum based on utilization plus (iii) a commitment fee of 0.50% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The reserve-based credit facility contains various covenants that limit, among other things, our ability and certain of our subsidiaries ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions.

In addition, we are required to maintain (i) a ratio of Total Net Debt (defined as Debt (generally indebtedness permitted to be incurred by us under the reserve-based credit facility) less Available Cash (generally, cash, cash equivalents, and cash reserves of the Company)) to Adjusted EBITDA (generally, for any period, the sum of consolidated net income for such period plus (minus) the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets, (gain) loss on sale of assets, exploration costs, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on derivatives and realized (gain) loss on cancelled derivatives, and other similar charges) of not more than 3.50 to 1.0; (ii) Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and (iii) consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities and current maturities of debt (to the extent such payments are not past due), of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143 (including the current liabilities in respect of the termination of oil and natural gas and interest rate swaps). All financial covenants are calculated using our consolidated financial information.

The reserve-based credit facility also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, guaranties not being valid under the reserve-based credit facility and a change of control. A change of control is generally defined as the occurrence of both of the following events: (i) wholly owned subsidiaries of Constellation are the owner of 20% or less of an interest in us (which has now occurred) and (ii) any person or group of persons acting in concert are the owner of more than 35% of an interest in us. If an event of default occurs, the lenders will be able to accelerate the maturity of the reserve-based credit facility and exercise other rights and remedies. The reserve-based credit facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the reserve-based credit facility and would be in default, which could cause all of our existing indebtedness to become immediately due and payable.

The reserve-based credit facility limits our ability to pay distributions to unitholders. We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the reserve-based credit facility, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the reserve-based credit facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. As of December 31, 2011, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions. The reserve-based credit facility permits us to hedge our projected monthly production, provided that (a) for the immediately ensuing twelve month period, the volumes of production hedged in any month may not exceed our reasonable business judgment of the production for such month consistent with the application of petroleum engineering methodologies for estimating proved developed producing reserves based on the then-current strip pricing (provided that such projection shall not be more than 115% of the proved developed producing reserves forecast for the same period derived from the most recent reserve report of our petroleum engineers using the then strip pricing), and (b) for the period beyond twelve months, the volumes of production hedged in any month may not exceed the reasonably anticipated projected production from proved developed producing reserves estimated by our petroleum engineers. The reserve-based credit facility also permits us to hedge the interest rate on up to 90% of the then-outstanding principal amounts of our indebtedness for borrowed money.

The reserve-based credit facility contains no covenants related to PostRock s or Constellation s ownership in us.

Debt Issue Costs

As of December 31, 2011, our unamortized debt issue costs were approximately $2.4 million. These costs are being amortized over the life of the credit facility through November 2013.

Funds Available for Borrowing

As of December 31, 2011, we had $98.4 million in outstanding debt under our reserve-based credit facility and $26.6 million in remaining borrowing capacity. As of December 31, 2010, we had $165.0 million in outstanding debt under our reserve-based credit facility.

Compliance with Financial Covenants

At December 31, 2011, we believe that we were in compliance with the financial covenant ratios contained in our reserve-based credit facility. We monitor compliance on an ongoing basis. As of December 31, 2011, our actual Total Net Debt to annual Adjusted EBITDA ratio was 1.5 to 1.0 as compared with a required ratio of not greater than 3.5 to 1.0, our actual ratio of consolidated current assets to consolidated current liabilities was 3.6 to 1.0 as compared with a required ratio of not less than 1.0 to 1.0, and our actual quarterly Adjusted EBITDA to cash interest expense ratio was 13.5 to 1.0 as compared with a required ratio of not less than 2.5 to 1.0.

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If we are unable to remain in compliance with the debt covenants associated with our reserve-based credit facility or maintain the required ratios discussed above, we could request waivers from the lenders in our bank group. Although the lenders may not provide a waiver, we could take additional steps in the event of not meeting the required ratios or in the event of a reduction in our borrowing base, as determined by our lenders, to a level that is below our outstanding debt. During 2011, we have used our surplus operating cash flows to reduce our outstanding debt. If it becomes necessary to reduce debt by amounts that exceed our operating cash flows, we could reduce capital expenditures, suspend our quarterly distributions to unitholders, sell oil and natural gas properties, liquidate in-the-money derivative positions, reduce operating and administrative costs, or take additional steps to increase liquidity. If we become unable to obtain a waiver and were unsuccessful at reducing our debt to the necessary level, our debt could become due and payable upon acceleration by the lenders. To the extent that we do not enter into an agreement to refinance or extend the due date on the reserve-based credit facility, the outstanding debt balance at November 13, 2012, will become a current liability.

5. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties consist of the following:

	December 31, 2011	December 31, 2010 (In 000 s)	December 31, 2009
Oil and natural gas properties and related equipment (successful efforts method)			
Property (acreage) costs			
Proved property	$ 785,089	$ 772,450	$ 756,461
Unproved property	1,321	698	37,147
Total property costs	786,410	773,148	793,608
Materials and supplies	1,243	2,073	4,312
Land	912	912	912
Total	788,565	776,133	798,832
Less: Accumulated depreciation, depletion, amortization and impairments	(522,480)	(499,214)	(186,207)
Oil and natural gas properties and equipment, net	$ 266,085	$ 276,919	$ 612,625

Depletion, depreciation, amortization and impairments consisted of the following:

	Twelve Months Ended December 31, 2011	Twelve Months Ended December 31, 2010 (In 000 s)	Twelve Months Ended December 31, 2009
DD&A of oil and natural gas-related assets	$ 22,139	$ 85,263	$ 71,173
Asset impairments	2,935	272,487	5,113
Total	$ 25,074	$ 357,750	$ 76,286

Impairment of Oil and Natural Gas Properties and Other Non-Current Assets

In 2011, we recorded a total non-cash impairment charge of approximately $2.9 million, composed of $1.6 million to impair the value of our oil and natural gas properties in the Central Kansas Uplift, $1.0 million related to the extinguishment of the NPI and $0.3 million to impair certain of our wells in the Woodford Shale. This impairment of our proved oil and natural gas properties in the Central Kansas Uplift and the impairment of certain of our wells located in the Woodford Shale were recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by estimated cash flows reported in a third party reserve report. This report was based upon future oil and natural gas prices, which are based on observable inputs adjusted for basis differentials, which are Level 2 inputs. Significant assumptions in valuing the proved reserves included the reserve quantities, anticipated drilling and operating costs, anticipated production taxes, future expected oil and natural gas prices and basis differentials, anticipated drilling schedules, anticipated production declines, and an appropriate discount rate commensurate with the risk of the underlying cash flow estimates for the properties of 10.0%. The impairments were caused by the impact of lower future oil and natural gas prices and performance-related reserve revisions. After the impairments, the remaining net capitalized costs subject to impairment in the Woodford Shale is approximately $3.9 million and in the Central Kansas Uplift is approximately $3.5 million. Cash flow estimates for the impairment testing exclude derivative instruments used to mitigate the risk of lower future oil and natural gas prices. These asset impairments have no impact on our cash flows, liquidity position, or debt covenants.

In 2010, we recorded a total non-cash impairment charge of approximately $272.5 million, composed of $263.4 million to impair the value of our proved and unproved oil and natural gas properties in the Cherokee Basin, $6.3 million to impair our other non-current assets related to our activities in the Cherokee Basin, $0.4 million to impair the value of inventory in the Cherokee basin, $1.9 million to impair certain of our wells in the Woodford Shale, and $0.5 million to impair the value of our casing inventory. This impairment of our proved Cherokee Basin oil and natural gas properties and the impairment of certain of our wells located in the Woodford Shale was recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by estimated cash flows reported in a third party reserve report. This report was based upon future oil and natural gas prices, which are based on observable inputs adjusted for basis differentials, which are Level 2 inputs. Significant assumptions in valuing the proved reserves included the reserve quantities, anticipated drilling and operating costs, anticipated production taxes, future expected natural gas prices and basis differentials, anticipated drilling schedules, anticipated production declines, and an appropriate discount rate commensurate with the risk of the underlying cash flow estimates for the coalbed methane and non-operated shale properties of 10.0%. The impairment was caused by the impact of lower future natural gas prices. Particularly during the third quarter of 2010, future natural gas price curves shifted significantly lower in the Cherokee Basin, especially in the years 5 through 15, and an impairment was recorded. Cash flow estimates for the impairment testing exclude derivative instruments used to mitigate the risk of lower future natural gas prices. Our unproved properties in the Cherokee Basin were impaired based on the drilling locations for the probable and possible reserves becoming uneconomic at the lower future expected natural gas prices, our limited future capital budgets, and our future expected drilling schedules. Significant assumptions in valuing the unproved reserves included the evaluation of the probable and possible reserves included in the third party reserve report, future expected natural gas prices and basis differentials, and our anticipated drilling schedules and capital availability. The impairment of our other non-current assets was recorded because the net capitalized costs of the intangible assets exceeded the fair value of the assets as measured by estimated cash flows based on lower observable future expected natural gas prices adjusted for basis differentials, which are Level 2 inputs. These asset impairments had no impact on our cash flows, liquidity position, or debt covenants. As of December 31, 2010, we reviewed our other properties for impairment and the estimated undiscounted future cash flows exceeded the net capitalized costs, thus no impairment was required to be recognized.

In 2009, we recorded a total non-cash impairment charge of approximately $5.1 million, composed of $4.8 million to impair the value of certain of our wells located in the Woodford Shale in Oklahoma and approximately $0.3 million to impair the value of certain obsolete inventory and straight-line assets. This impairment was recorded because the carrying value of certain of the wells exceeded the fair value of the wells as measured by estimated cash flows reported in a third party reserve report that was based upon future expected oil and natural gas prices, which are based on observable inputs adjusted for basis differentials, which are Level 2 inputs. The impairment is primarily caused by the impact of lower future expected natural gas prices. Cash flow estimates for the impairment testing exclude derivative instruments. As of December 31, 2009, we reviewed our other properties for impairment and the estimated undiscounted future cash flows exceeded the net capitalized costs, thus no impairment was required to be recognized.

Asset Sales

In 2011, we sold miscellaneous equipment and surplus inventory for approximately $0.1 million and recorded a gain of approximately $0.02 million on the sales. See Note 17 for additional information.

In 2010, we sold miscellaneous equipment and surplus inventory for approximately $0.1 million and recorded a gain of approximately $0.02 million on the sales.

In 2009, we sold two tractors, casing, a ditch witch, and other miscellaneous equipment for approximately $0.1 million and recorded a loss of approximately $0.03 million on the sales.

Useful Lives

Our furniture, fixtures, and equipment are depreciated over a life of one to seven years, buildings are depreciated over a life of twenty years, and pipeline and gathering systems are depreciated over a life of twenty-five to forty years.

Exploration and Dry Hole Costs

Our exploration and dry hole costs were $0.1 million, $0.8 million, and $0.9 million in 2011, 2010, and 2009, respectively. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on our unproved properties.

6. BENEFIT PLANS

Eligible employees of CEP participate in an employment savings plan. Matching contributions made by us were approximately $0.5 million, $0.5 million, and $0.4 million for the years ended December 31, 2011, 2010, and 2009 respectively.

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7. RELATED PARTY TRANSACTIONS

Unit Ownership

Both Constellation and PostRock, through subsidiaries, own a portion of our outstanding units. As of December 31, 2011, CEPM, a subsidiary of PostRock, owns all of our Class A units and 5,918,894 of our Class B common units. CEPH, a subsidiary of Constellation, owns all of our Class C management incentive interests and all of our Class D interests.

PostRock-Related Announcements

On August 8, 2011, PostRock announced that it had acquired all of our Class A units and 3,128,670 of our Class B common units in a transaction with Constellation. As a result of the transaction, PostRock received the right to appoint two Class A managers to our board of managers. On December 19, 2011, PostRock acquired Constellation s remaining 2,790,224 Class B common units. The units acquired in these two transactions in aggregate represent a 26.4% interest in us as of December 31, 2011. Approval of these transactions was neither required nor given by our board of managers or conflicts committee. We believe PostRock is now an interested unitholder under Section 203 of the Delaware General Corporation Law. Section 203 as it applies to us prohibits an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in business combinations with us for three years following the time such person becomes an interested unitholder without the approval of our board of managers and the vote of 66 2/3% of our outstanding Class B common units, excluding those held by the interested unitholder. Section 203 broadly defines business combination to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. In addition to limiting our ability to enter into transactions with PostRock or its affiliates, this provision of our limited liability company agreement could have an anti-takeover effect with respect to transactions not approved in advance by our board of managers, including discouraging takeover attempts that might result in a premium over the market price for our common units.

Subsidiaries of Constellation agreed to reimburse us for certain fees and expenses that we incurred in connection with a proposed Constellation and PostRock transaction that was announced on June 21, 2011, and expenses associated with the Torch derivative litigation settlement. We received expense reimbursements of approximately $0.9 million, $0.1 million and $0.2 million from subsidiaries of Constellation during 2011, 2010 and 2009, respectively.

Class C Management Incentive Interests

CEPH, a subsidiary of Constellation, holds the Class C management incentive interests in CEP. These management incentive interests represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in our limited liability company agreement) has been achieved and certain other tests have been met. None of these applicable tests have yet to be met and CEPH has not been entitled to receive any management incentive interest distributions.

Class D Interests

Due to their contingently redeemable feature, the Class D interests have been treated as preferred units subject to contingent redemption. CEPH, a subsidiary of Constellation, holds all of our Class D interests. As described in Note 10, we purchased the NPI from the Trust for $1.0 million as part of the settlement of Torch derivative litigation. Because the NPI was granted to the Trust by a predecessor-in-interest to us, the NPI was extinguished when the NPI was assigned to us by the Trust. The NPI no longer burdens our properties in the Robinson s Bend Field. Further, since the NPI will no longer be paid based upon the sharing arrangement and we have suspended distributions since June 2009, there should be no further distributions required on the Class D interests, as the capital account balance associated with the $6.7 million in unpaid Class D distributions was reduced to zero effective upon the extinguishment of the NPI by transferring its capital account balance to permanent equity. The Class D interests will remain outstanding until the liquidation of CEP, but will be entitled to a zero liquidation amount.

Management Services Agreement

In November 2006, we entered into a management services agreement with a subsidiary of Constellation, to provide certain management, technical and administrative services. This agreement was terminated effective December 15, 2009. Each quarter, Constellation charged us an amount for services provided to us. This amount was agreed to annually and included a portion of the compensation paid by Constellation and its affiliates to personnel who spent time on our business and affairs. The conflicts committee of our board of managers determined that the amounts paid by us for the services performed were fair to and in the best interests of the Company. These costs totaled approximately $1.4 million for the year ended December 31, 2009.

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Natural Gas Purchases

Through March 31, 2009, CCG purchased natural gas from us. The arrangement was reviewed by the conflicts committee of our board of managers. The committee found that the arrangement was fair to and in the best interests of the Company. For the twelve months ended December 31, 2009, CCG paid us $5.7 million for natural gas purchases.

8. COMMITMENTS AND CONTINGENCIES

In the course of its normal business affairs, we are subject to possible loss contingencies arising from federal, state and local environmental, health and safety laws and regulations and third-party litigation and lawsuits. As of December 31, 2011, there were no matters which, in the opinion of management, would have a material adverse effect on the financial position, results of operations or cash flows of CEP, and its subsidiaries, taken as a whole.

9. ASSET RETIREMENT OBLIGATION

We recognize the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred if a reasonable estimate of fair value can be made. Each period, we accrete the ARO to its then present value. The associated asset retirement cost (ARC) is capitalized as part of the carrying amount of our natural gas properties equipment and facilities. Subsequently, the ARC is depreciated using a systematic and rational method over the asset s useful life. The ARO that we record relates to the plugging and abandonment of natural gas wells, and decommissioning of the gas gathering and processing facilities.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions result in adjustments to the recorded fair value of the existing ARO, a corresponding adjustment is made to the ARC capitalized as part of the oil and natural gas property balance.

The following table is a reconciliation of the ARO:

	December 31, 2011	December 31, 2010 (In 000 s)	December 31, 2009
Asset retirement obligation, beginning balance	$ 13,024	$ 12,129	$ 6,754
Liabilities incurred from acquisition of the properties		32	
Liabilities incurred	143	83	3,873
Liabilities settled	(27)	(42)	(12)
Revisions to prior estimates			1,108
Accretion expense	907	822	406
Asset retirement obligation, ending balance	$ 14,047	$ 13,024	$ 12,129

Additional retirement obligations increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Actual expenditures for abandonments of oil and natural gas wells and other facilities reduce the liability for asset retirement obligation. In 2011, 2010, and 2009, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing asset retirement obligations.

10. NET PROFITS INTEREST

Certain of our wells in the Robinson s Bend Field were subject to a non-operating NPI until December 2011. The cumulative Net NPI Proceeds balance must have been greater than $0 before any payments for the NPI were made to the Torch Energy Royalty Trust (Trust). The cumulative Net NPI Proceeds was a deficit for the twelve months ended December 31, 2011, 2010 and 2009, and as a result, no payments for the NPI were made to the Trust.

Settlement of the Litigation Related to Trust Termination and Extinguishment of the NPI

On January 8, 2009, we were served by Trust Venture, on behalf of the Trust, with a purported derivative action filed in the Circuit Court of Tuscaloosa County, Alabama (the Court). The lawsuit alleged, among other things, a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserted that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit sought unspecified damages and an accounting of the NPI. The lawsuit was settled in June 2011. The settlement with Trust Venture, its successor and the Trust provided, among other things, that we pay $1.2 million to reimburse Trust Venture and its successor for their legal fees and expenses incurred in prosecuting the lawsuit and that we acquire the NPI from the Trust for $1.0 million. When the NPI was assigned to us by the Trust in the fourth quarter of 2011, the NPI was extinguished. The NPI no longer burdens our properties in the Robinson s Bend Field, and we recognized a $1.0 million charge to impair the value of the extinguished NPI contract that was acquired. As described in Note 7 above, the finalization of this settlement impacts the liquidation value of our Class D interests.

11. ENVIRONMENTAL LIABILITY

We are subject to costs resulting from federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. As of December 31, 2011, and 2010, we had no material accrued environmental obligations.

12. UNIT-BASED COMPENSATION

We recognized approximately $1.3 million and $1.8 million of expense related to our unit-based compensation plans in the twelve months ended December 31, 2011, and December 31, 2010, respectively. As of December 31, 2011, we had approximately $2.7 million in unrecognized compensation expense related to our unit-based compensation plans expected to be recognized through the first quarter of 2015.

Unit-Based Awards Granted in 2011

In the second quarter of 2011, the compensation committee and board of managers granted approximately 31,000 unit-based awards under our 2009 Omnibus Incentive Compensation Plan to our named executive officers and other key employees. These unit-based awards will be settled in cash instead of units and the employees may earn between 0% and 200% of the number of awards granted based on the achievement of absolute CEP unit price targets during a three-year performance period from January 2011 through December 2013. CEP unit price targets and corresponding cash payout levels are as follows:

Threshold 50% cash payout at $3.50/CEP unit

Target 100% cash payout at $4.00/CEP unit

Stretch 200% cash payout at $6.00/CEP unit

Cash payouts for results between these points will be interpolated on a linear basis.

Failure to achieve the threshold CEP unit price will result in no cash payout of the awards granted. The determination of the level of achievement and number of awards earned will be based on a calculation of CEP s unit price at the end of the performance period. This price calculation will be based on the average of the closing daily prices for the final 20 trading days of the performance period. In addition, the executive unit-based awards will vest earlier if any of the following events occur: a change of control, a CEG ownership event, death of the executive, delivery by the Company of a disability notice with respect to the executive, or an involuntary termination of the executive (with each of the foregoing terms having the corresponding definitions set forth in the respective employment agreement with the Company). The awards may vest earlier with respect to the other key employees under certain of these circumstances. Any cash payment will be made at the end of the performance period except in the case of certain change of control events, which may accelerate payment. The grants are accounted for in our financial statements as a liability-classified award with the fair value remeasured each reporting period until settlement. The fair market value of these awards was approximately $0.9 million and $0.4 million at the grant date and December 31, 2011, respectively. We recognized approximately $0.1 million in non-cash compensation expenses related to the program for the year ended December 31, 2011. The program is intended to benefit our unitholders by focusing the recipient s efforts on increasing our absolute unit price over the performance period.

2010 Grants

Grants under the 2009 Omnibus Incentive Compensation Plan

In March 2010, we granted approximately 498,000 restricted common unit awards to certain employees in Texas under the 2009 Omnibus Incentive Compensation Plan. These units had a total fair market value of approximately $1.7 million based on the closing price of our common units on NYSE Arca on March 1, 2010. All of these service-based restricted units will vest on a five year ratable schedule beginning on March 1, 2010.

Grants under the Long-Term Incentive Program

We granted approximately 195,852 restricted common unit awards under the Long-Term Incentive Plan on March 1, 2010, to certain field employees in Alabama, Kansas, and Oklahoma and to certain employees in Texas. These units had a total fair market value of approximately $0.7 million based on the closing price of our common units on NYSE Arca on March 1, 2010. These service-based restricted units will vest on a three year ratable schedule beginning on March 1, 2010, except for certain employees in Texas which will vest on a five year ratable schedule beginning on March 1, 2010.

We granted approximately 54,747 restricted common unit awards under the Long-Term Incentive Plan on March 1, 2010, to our three independent managers. These units had a total fair market value of approximately $0.2 million based on the closing price of our common units on NYSE Arca on March 1, 2010. These awards vested in March 2011.

2009 Grants

Grants under the 2009 Omnibus Incentive Compensation Plan

We granted approximately 959,914 notional unit awards to certain employees in Texas and 80,937 notional unit awards to our three independent managers under the 2009 Omnibus Incentive Compensation Plan prior to the plan s approval by our common unitholders. Upon the plan s approval on December 1, 2009, these notional units were converted into restricted common units. These units had a total fair market value of approximately $3,518,076 based on the closing price of our common units on NYSE Arca on December 1, 2009. Additionally, in December 2009 we granted approximately 36,170 restricted common units to certain employees in Texas. These units had a total fair market value of approximately $127,327 based on the closing price of our common units on NYSE Arca on their grant dates. All of these service-based restricted units will vest on a five year ratable schedule beginning in 2010 except those granted to our three independent managers which vested in full in March 2010.

Each of these unvested restricted common unit carried the right to receive distribution credits when any distributions were made by us on our common units. Any distribution credits will accrue and be settled in cash or common units, in the discretion of the compensation committee, upon the vesting of the underlying restricted common unit. As of December 31, 2009, a total of 33,467 notional units had been issued as distribution credits.

Until the notional units granted under the 2009 Omnibus Incentive Compensation Plan were converted into restricted common units upon unitholder approval, the notional units were accounted for using the variable plan accounting method. Under the variable method, compensation costs were measured using the quoted market price of our common units on each measurement date and multiplying the compensation cost by the percentage of the vesting period served through the measurement date. Increases or decreases in the quoted market price of the common units between the date of the grant and each measurement date resulted in a change in the compensation expense recognized for the notional units.

Grants under the Executive Inducement Bonus Program

On May 1, 2009, we made grants of an aggregate of 161,871 restricted common units under the Executive Inducement Bonus Program to induce four executives to become employed by us, with an approximate aggregate grant-date value of $500,181 based on the closing price per unit on May 1, 2009. The units vested 50% on January 1, 2010 and 50% vested on January 1, 2011.

Each of these unvested restricted common unit carried the right to receive distribution credits when any distributions were made by us on our common units. Any distribution credits will accrue and be settled in cash or common units, in the discretion of the compensation committee, upon the vesting of the underlying restricted common unit. As of December 31, 2009, a total of 5,612 restricted units had been issued as distribution credits.

2009 Grants

Grants under the Long-Term Incentive Program

We granted approximately 163,340 restricted common unit awards under the Long-Term Incentive Plan on August 1, 2009, to certain field employees in Alabama, Kansas, and Oklahoma. These units had a total fair market value of approximately $529,222 based on the average of the high and low trading price of our common units on NYSE Arca on August 3, 2009. These service-based restricted units will vest on a three year ratable schedule beginning on August 1, 2010.

13. DISTRIBUTIONS TO UNITHOLDERS

Distributions through December 31, 2011

Beginning in June 2009, we suspended our quarterly distributions to unitholders. For the quarters ended March 31, June 30 and September 30, 2011, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions. See Note 17 for additional information.

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Distributions through December 31, 2010

Beginning in June 2009, we have suspended our quarterly distributions to unitholders. For the twelve months ended December 31, 2010, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions.

Distributions through December 31, 2009

We suspended our quarterly distributions to unitholders for the quarters ended December 31, September 30, and June 30, 2009, to remain in compliance with the covenants associated with our reserve-based credit facility.

On May 15, 2009, we paid a distribution for the first quarter of 2009 to the unitholders of record at May 8, 2009. The distribution was paid to holders of common units and Class A units at a rate of $0.13 per unit.

On February 13, 2009, we paid a distribution for the fourth quarter of 2008 to the unitholders of record at February 6, 2009. The distribution was paid to holders of common units and Class A units at a rate of $0.13 per unit.

14. MEMBERS EQUITY

2011 Equity

At December 31, 2011, we had 485,033 Class A units and 23,766,632 Class B common units outstanding, which included 149,869 unvested restricted common units issued under our Long-Term Incentive Plan and 962,281 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan. See Note 17 for additional information.

At December 31, 2011, we had granted 335,529 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 185,660 have vested as of December 31, 2011.

At December 31, 2011, we had granted 1,406,725 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 444,444 have vested as of December 31, 2011.

For the year ended December 31, 2011, 119,963 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.3 million, have been returned to their respective plan and are available for future grants.

2010 Equity

At December 31, 2010, we had 487,750 Class A units and 23,899,758 Class B units outstanding, which included 309,225 unvested restricted common units issued under our Long-Term Incentive Plan, 83,745 unvested restricted common units issued under our Executive Inducement Bonus Program, and 1,248,803 unvested restricted common units under our 2009 Omnibus Incentive Compensation Plan.

At December 31, 2010, we had granted 376,845 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 67,620 have vested as of December 31, 2010.

At December 31, 2010, we had granted 146,551 common units of the 300,000 common units available under our Executive Inducement Bonus Program. Of these grants, 62,807 have vested as of December 31, 2010.

At December 31, 2010, we had granted 1,477,598 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 228,795 have vested as of December 31, 2010.

For the twelve months ended December 31, 2010, 92,353 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.4 million, have been returned to their respective plan and are available for future grants.

2009 Equity

At December 31, 2009, we had 476,950 Class A units and 23,376,136 Class B units outstanding, which included 177,674 unvested restricted common units issued under our Long-Term Incentive Plan, 167,484 unvested restricted common units issued under our Executive Inducement Bonus Program, and 1,110,488 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan.

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At December 31, 2009, we had granted 199,401 common units of the 450,000 common units available under our Long-term Incentive Plan. Of these grants, 21,727 have vested as of December 31, 2009.

At December 31, 2009, we had granted 167,484 common units of the 300,000 common units available under our Executive Inducement Bonus Program. Of these grants, none have vested as of December 31, 2009.

At December 31, 2009, we had granted 1,110,488 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, none have vested as of December 31, 2009.

15. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES (UNAUDITED)

The Supplementary Information on Oil and Natural Gas Producing Activities is presented as required by the appropriate authoritative guidance. The supplemental information includes capitalized costs related to oil and natural gas producing activities; costs incurred for the acquisition of oil and natural gas producing activities, exploration and development activities and the results of operations from oil and natural gas producing activities.

Supplemental information is also provided for per unit production costs; oil and natural gas production and average sales prices; the estimated quantities of proved oil and natural gas reserves; the standardized measure of discounted future net cash flows associated with proved reserves and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved reserves.

Costs

The following table sets forth capitalized costs for the years ended December 31, 2011, 2010, and 2009:

	December 31, 2011	December 31, 2010 (In 000 s)	December 31, 2009
Capitalized costs at the end of the period:[(a)]			
Oil and natural gas properties and related equipment (successful efforts method)			
Property (acreage) costs			
Proved property	$ 785,089	$ 772,450	$ 756,461
Unproved property	1,321	698	37,147
Total property costs	786,410	773,148	793,608
Materials and supplies	1,243	2,073	4,312
Land	912	912	912
Total	788,565	776,133	798,832
Less: Accumulated depreciation, depletion, amortization and impairments	(522,480)	(499,214)	(186,207)
Net capitalized cost	$ 266,085	$ 276,919	$ 612,625

(a) Capitalized costs include the cost of equipment and facilities for our oil and natural gas producing activities. Proved property costs include capitalized costs for leaseholds holding proved reserves; development wells and related equipment and facilities (including uncompleted development well costs); and support equipment. Unproved property costs include capitalized costs for oil and natural gas leaseholds where proved reserves do not exist.

The following table sets forth costs incurred for oil and natural gas producing activities for the years ended December 31, 2011, 2010, and 2009:

	For the year ended December 31, 2011	For the year ended December 31, 2010	For the year ended December 31, 2009
		(In 000 s)	
Costs incurred for the period:			
Acquisition of properties			
Proved	$ (281)	$ 5,691	$ 170
Unproved	631	678	121
Development costs	10,967	7,973	22,913
Total costs incurred	$ 11,317	$ 14,342	$ 23,204

The development costs for the years ended December 31, 2011, 2010, and 2009 primarily represent costs to develop our proved undeveloped reserves. During 2011, approximately 80% of our development expenditures of $10.9 million were for locations in the Cherokee Basin and approximately 20% of the expenditures were for locations in the Black Warrior Basin. We estimate that we will spend $18.8 million, $18.3 million, and $16.7 million to develop our total proved reserves in 2012, 2013, and 2014, respectively. Our 2011 acquisition of properties included leasing $0.6 million of unproved acreage on our concession in Osage County, Oklahoma and other areas of the Cherokee Basin, offset by the receipt of $0.3 million in post-closing adjustments for our December 2010 acquisition of oil properties in the Central Kansas Uplift.

Our exploration and dry hole costs were $0.1 million, $0.8 million, and $0.9 million in 2011, 2010, and 2009, respectively.

Results of Operations

The revenues and expenses associated directly with oil and natural gas producing activities are reflected in the Consolidated Statements of Operations and Comprehensive Income (Loss). All of our operations are oil and natural gas producing activities located in the United States.

Net Proved Oil and Natural Gas Reserves

The following table sets forth information with respect to changes in proved developed and undeveloped reserves. This information excludes reserves related to royalty and net profit interests. All of our reserves are located in the United States.

	For the year ended December 31, 2011	For the year ended December 31, 2010	For the year ended December 31, 2009
		(In MMcfe)	
Beginning Balance	169,007	131,180	232,414
Extensions and discoveries	1,725	226	1,103
Purchases of reserves in place		805	
Sales of reserves in place			
Revisions of previous estimates	42,483	49,027	(85,276)
Production	(11,885)	(12,231)	(17,061)
Ending Balance	201,330	169,007	131,180
Total proved developed reserves	152,632	127,627	112,059
Total proved undeveloped reserves	48,698	41,380	19,121

Reserves and Related Estimates

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Our 2011, 2010 and 2009 reserve estimates were prepared in accordance with the FASB and SEC rules for oil and gas reporting effective at December 31, 2009 using the SEC-required price.

Our December 31, 2011, 2010 and 2009 proved reserve estimates were 201.3 Bcfe, 169.0 Bcfe and 131.2 Bcfe, respectively. For these years, NSAI, an independent petroleum engineering firm, prepared the estimates of our proved reserves which were used to prepare our financial statements.

Our 2011 estimates of total proved reserves increased 32.3 Bcfe from 2010. Of this increase in 2011, 1.7 Bcfe was related to extensions and discoveries in the Cherokee Basin, composed of 1.5 Bcfe of proved undeveloped reserves added for oil opportunities and 0.2 Bcfe of natural gas reserves. Our reserve revisions of 42.5 Bcfe are primarily the result of lower lease operating costs in the Cherokee Basin, which resulted in positive revisions of approximately 22.4 Bcfe, and increased performance and lower production declines, which resulted in positive revisions of approximately 13.2 Bcfe in the Black Warrior Basin and 12.7 Bcfe in the Cherokee Basin. The remainder of our positive revisions was related to our oil drilling

program in the Cherokee Basin and Central Kansas Uplift. Our positive reserve revisions were offset by the impact of a lower SEC-required price used to calculate our reserves in 2011. Our reserves are 97% natural gas and are sensitive to higher prices for natural gas and basis differentials in the Mid-Continent region. Although we utilize swaps and basis swaps to mitigate commodity price risk and basis differentials, these derivatives are not used when preparing our reserve report based on SEC rules. The SEC-required price used to prepare our reserve report was $4.20 in the Black Warrior Basin and $3.88 in the Cherokee Basin. The SEC-required prices used in the Black Warrior Basin and in the Cherokee Basin declined from 2010 to 2011 by $0.35 and $0.10, respectively. These price declines resulted in price-related revisions of approximately 7.8 Bcfe. The remainder of the change in our reserves from 2010 to 2011 was the production in our reserve report of 11.9 Bcfe. Our actual 2011 production of 13.7 Bcfe is 1.8 Bcfe higher than what our 2010 reserve report estimated for 2011. Certain of our wells that actually produced natural gas in 2011 were not included in our 2010 reserve report as they were deemed uneconomic at the SEC-required price which excludes the impact of our swaps and basis swaps used to mitigate commodity price risk and basis differentials. Any of our locations that are scheduled to be drilled after 5 years are classified as probable or possible reserves to the extent they are economic.

Our 2010 estimates of total proved reserves increased 37.8 Bcfe from 2009 primarily due to reserve revisions due to a higher SEC-required price for natural gas. Our reserves were 98% natural gas and were sensitive to higher prices for natural gas and basis differentials in the Mid-Continent region. Although we utilized swaps and basis swaps to mitigate commodity price risk and basis differentials, these derivatives were not used when preparing our reserve report based on SEC rules. The SEC-required price used to prepare our reserve report was $4.55 in the Black Warrior Basin and $3.98 in the Cherokee Basin. The SEC-required price in the Cherokee Basin increased $0.88 from 2009 to 2010 which made 30.2 Bcfe of our proved undeveloped locations economic in the Cherokee Basin. These locations had previously been classified as probable reserves. We also removed approximately 8.0 Bcfe in proven undeveloped locations in the Black Warrior Basin because of approximately $3.0 million in lower capital being deployed in the last four years of our five year plan. Any of our locations that were scheduled to be drilled after 5 years were classified as probable or possible reserves to the extent they were economic. The remainder of the change in our reserves from 2009 to 2010 was 0.8 Bcfe in proved producing reserves acquired in Kansas and Nebraska, additional price-related revisions to our proved producing and proved non-producing of 26.8 Bcfe which were offset by production from wells included in our 2009 reserve report of 12.2 Bcfe. Due to the low SEC-required prices used to prepare our reserve reports, certain of our wells that actually produced natural gas in 2010 were not included in our 2009 reserve report as they were deemed uneconomic at the SEC-required price which excludes the impact of our swaps and basis swaps used to mitigate commodity price risk and basis differentials. Our actual 2010 production of 15.0 Bcfe is 3.0 Bcfe higher than what our 2009 reserve report estimated for 2010. No reserves were attributed to the NPI in 2010.

Our 2009 estimates of total proved reserves decreased 101.2 Bcfe from 2008 primarily due to reserve revisions due to a significantly lower SEC-required price for natural gas. Our reserves were 99% natural gas and are sensitive to lower prices for natural gas and basis differentials in the Mid-Continent region. The SEC-required price used to prepare our reserve report was $3.92 for NYMEX and $3.11 in the Cherokee Basin. Although we utilized swaps and basis swaps to mitigate commodity price risk and basis differentials, these derivatives were not used when preparing our reserve report based on SEC rules. This low SEC-required price makes all of our proved undeveloped locations uneconomic in the Cherokee Basin in 2009. These locations were then classified as probable reserves. We also removed approximately 23.9 Bcfe in proven undeveloped locations in the Black Warrior Basin because of the new SEC requirement to only record locations that are scheduled to be drilled within the next 5 years. Any of our locations that were scheduled to be drilled after 5 years are classified as probable or possible reserves to the extent they are economic. These declines were partially offset by additional proved undeveloped reserve additions in the Black Warrior Basin because of a state ruling allowing 40-acre spacing throughout the Robinson s Bend Field. No reserves were attributed to the NPI in 2009.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas Reserves, Including a Reconciliation of Changes Therein

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved oil and natural gas reserves. Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below.

Future cash inflows are calculated by applying the SEC-required prices of oil and natural gas relating to our proved reserves to the year-end quantities of those reserves. Future cash inflows exclude the impact of our hedging program. Future development and production costs represent the estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. In addition, asset retirement obligations are included within future production and development costs. There are no future income tax expenses because CEP is a non-taxable entity.

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The assumptions used to compute estimated future cash inflows do not necessarily reflect expectations of actual revenues or costs or their present values. In addition, variations from expected production rates could result directly or indirectly from factors outside of our control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production; however, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

The following table summarizes the standardized measure of estimated discounted future cash flows from the oil and natural gas properties:

	For the year ended December 31, 2011	For the year ended December 31, 2010 (In 000 s)	For the year ended December 31, 2009
Future cash inflows	$ 913,532	$ 751,384	$ 522,145
Future production costs	(500,308)	(404,350)	(277,881)
Future estimated development costs	(97,367)	(77,055)	(33,055)
Future net cash flows	315,857	269,979	211,209
10% annual discount for estimated timing of cash flows	(155,166)	(138,292)	(114,009)
Standardized measure of discounted estimated future net cash flows related to proved gas reserves	$ 160,691	$ 131,687	$ 97,200

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

	For the year Ended December 31, 2011	For the year Ended December 31, 2010 (In 000 s)	For the year Ended December 31, 2009
Beginning of the period	$ 131,687	$ 97,200	$ 228,914
Sales and transfers of natural gas, net of production costs	(29,584)	(22,017)	(48,396)
Net changes in prices and production costs related to future production	144	9,480	(98,905)
Development costs incurred during the period	7,166	6,920	26,004
Changes in extensions and discoveries	8,170	424	1,022
Revisions of previous quantity estimates	42,586	45,556	(72,767)
Purchase of reserves in place		4,773	
Accretion discount	13,169	9,720	22,891
Other	(12,647)	(20,369)	38,437
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 160,691	$ 131,687	$ 97,200

16. SUPPLEMENTAL QUARTERLY FINANCIAL DATA (Unaudited)

	2011 Quarters Ended (a)			
	March 31,	June 30,	September 30,	December 31,

			(In 000 s)	
Total revenue	$ 15,804	$ 24,424	$ 31,443	$ 33,546
Operating expenses	14,808	13,937	16,818	13,471
General and administrative expenses	4,223	4,012	4,548	3,816
Net income (loss)	$ (5,152)	$ 2,467	$ 7,144	$ 15,127
Earnings per unit Basic	$ (0.21)	$ 0.10	$ 0.29	$ 0.62
Earnings per unit Diluted	$ (0.21)	$ 0.10	$ 0.29	$ 0.62

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	2010 Quarters Ended			
	March 31,	June 30,	September 30,	December 31,
	(In 000 s)			
Total revenue	$ 64,518	$ 22,529	$ 47,743	$ 15,983
Operating expenses	37,307	35,924	305,980	15,793
General and administrative expenses	5,062	4,188	5,027	6,074
Net income (loss)	$ 18,058	$ (21,092)	$ (267,123)	$ (6,753)
Earnings per unit Basic	$ 0.75	$ (0.87)	$ (10.91)	$ (0.28)
Earnings per unit Diluted	$ 0.75	$ (0.87)	$ (10.91)	$ (0.28)

(a) The table for 2011 reflects the impact of revising our June 30 and September 30, 2011 quarterly data for a non-cash mark-to-market correction to interest expense. The net impact of this non-cash adjustment was a decrease to our net income in the amount of $0.8 million for the three months ended June 30, 2011, $0.3 million for the three months ended September 30, 2011 and a $(0.04) and $(0.01) impact on earnings per unit for the respective quarters. This non-cash adjustment had no impact on the twelve months ended December 31, 2011. We have determined that the adjustment is not material to our consolidated financial statements for any of the quarterly periods affected or to the annual period; therefore, no revisions have been made to the 2011 quarterly financial statements included in our previously filed Form 10-Qs for this matter.

17. SUBSEQUENT EVENTS

The following subsequent events have occurred between January 1, 2011, and February 29, 2012:

Reserve-Based Credit Facility

On February 21, 2012, Wells Fargo & Company announced it had agreed to purchase BNP Paribas energy lending business in the United States and that the purchase is subject to regulatory and other approvals and is expected to close in the second quarter of 2012. BNP Paribas is a lender in our reserve-based credit facility with 21.95% of our current borrowing base of $125.0 million, and a counterparty to certain of our commodity and interest rate derivatives. We would accelerate the amortization of approximately $0.5 million of our $2.4 million in unamortized debt issue costs upon the close of this purchase.

Members Equity

2011 Equity

At February 29, 2012, we had 483,936 Class A units and 23,712,857 Class B units outstanding, which included 124,728 unvested restricted common units issued under our Long-Term Incentive Plan and 286,793, unvested restricted common units under our 2009 Omnibus Incentive Compensation Plan.

At February 29, 2012, we had granted 325,272 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 185,660 have vested.

At February 29, 2012, we had granted 1,363,207 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 575,011 have vested.

Through February 29, 2012, 43,925 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.1 million, have been returned to their respective plan and are available for future grants.

Distribution

Our board of managers has suspended the quarterly distribution to our unitholders for the quarter ended December 31, 2011, which continues the temporary suspension we first announced in June 2009.

Asset Sales

In January 2012, we sold our interests in 14 gross non-operated oil wells in Kansas and Nebraska for approximately $1.4 million in cash, resulting in no material gain or loss on the asset sale.

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SCHEDULE II

CONSTELLATION ENERGY PARTNERS LLC

VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2011, 2010 and 2009

(In 000 s)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2011					
Environmental reserves	$	$			$
2010					
Environmental reserves	$ 193	$ (193)			$
2009					
Environmental reserves	$ 441	$ (248)			$ 193

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Constellation Energy Partners LLC, the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONSTELLATION ENERGY PARTNERS LLC

(REGISTRANT)

Date: February 29, 2012

By /s/ STEPHEN R. BRUNNER

Stephen R. Brunner

Chief Executive Officer, Chief Operating Officer and President

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

	Signature	Title	Date
Principal executive officer:			
By	/s/ STEPHEN R. BRUNNER **Stephen R. Brunner**	Chief Executive Officer, Chief Operating Officer and President	February 29, 2012
Principal financial officer and treasurer:			
By	/s/ CHARLES C. WARD **Charles C. Ward**	Chief Financial Officer and Treasurer	February 29, 2012
Principal accounting officer:			
By	/s/ MICHAEL B. HINEY **Michael B. Hiney**	Chief Accounting Officer and Controller	February 29, 2012
Managers:			
	/s/ RICHARD H. BACHMANN **Richard H. Bachmann**	Manager	February 29, 2012
	/s/ JOHN R. COLLINS **John R. Collins**	Manager	February 29, 2012
	/s/ RICHARD S. LANGDON **Richard S. Langdon**	Manager	February 29, 2012
	/s/ Hugh M. McIntosh **Hugh M. McIntosh**	Manager	February 29, 2012

/s/ John N. Seitz	Manager	February 29, 2012
John N. Seitz		

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EXHIBIT INDEX

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.2	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC, Kansas Production EQR, LLC and Kansas Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.3	Agreement of Merger, dated as of July 12, 2007, among AMVEST Osage, Inc., AMVEST Oil & Gas, Inc. and CEP Mid-Continent LLC, f/k/a CEP Cherokee Basin LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).
2.4	Purchase and Sale Agreement, dated as of August 2, 2007, between Newfield Exploration Mid-Continent Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).
2.5	Nominee Agreement, dated as of September 21, 2007, by and between Newfield Exploration Mid-Continent Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
2.6	Asset Purchase and Sale Agreement, dated as of May 12, 2005, by and among Everlast Energy LLC, RB Marketing Company LLC, Robinson s Bend Operating Company LLC and CBM Equity IV, LLC (incorporated herein by reference to Exhibit 10.9 to Amendment No. 2 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on September 29, 2006.
2.7	Agreement for Purchase and Sale, dated as of February 19, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.8	First Amendment to Agreement for Purchase and Sale, dated as of March 31, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.9	Oil and Gas Purchase Contract, dated as of October 1, 1993, by and between Torch Energy Marketing, Inc. and Torch Royalty Company (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2 to the Registration Statement on Form S-1 filed by Constellation Energy Partners LLC on June 29, 2006, File No. 333-134995).
3.1	Certificate of Formation of Constellation Energy Partners LLC, as amended (incorporated herein by reference to Exhibit 3.1 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 12, 2007, File No. 001-33147).
3.2	Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
3.3	Amendment No. 1 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of April 23, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
3.4	Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of July 25, 2007. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).
3.5	Amendment No. 3 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of September 21, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).

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Exhibit Number	Description
3.6	Amendment No. 4 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of December 28, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on December 28, 2007, File No. 001-33147).
10.1	Omnibus Agreement, dated as of November 20, 2006, among Constellation Energy Partners LLC, Constellation Energy Commodities Group, Inc., Robinson s Bend Production II, LLC, Robinson s Bend Operating II, LLC and Robinson s Bend Marketing II, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
10.2	$350,000,000 Amended and Restated Credit Agreement, dated as of November 13, 2009, among Constellation Energy Partners LLC, as borrower, The Royal Bank of Scotland plc, as administrative agent, RBS Securities Inc., as joint lead arranger and sole book runner, The Bank of Nova Scotia, as joint lead arranger and co-syndication agent, BNP Paribas, as joint lead arranger and co-syndication agent, and the lenders party hereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 16, 2009, File No. 001-33147).
10.3	First Amendment to Amended and Restated Credit Agreement, dated as of February 11, 2010, by and among Constellation Energy Partners LLC and the lenders signatory thereto (incorporated herein by reference to Exhibit 10.7 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 25,2010, File No. 001-33147).
10.4	Second Amendment to Amended and Restated Credit Agreement, effective as of June 3, 2011, by and among Constellation Energy Partners LLC, the lenders signatory thereto and The Royal Bank of Scotland plc (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 3, 2011, File No. 001-33147).
10.5	Trademark License Agreement, dated as of November 20, 2006, by and among Constellation Energy Group, Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
10.6	Exploration and Development Agreement, dated July 25, 2005, by and between The Osage Nation and AMVEST Osage, Inc. (incorporated herein by reference to Exhibit 10.23 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.7	Substituted and Replaced First Amendment to the Exploration and Development Agreement, dated October 18, 2006, by and between The Osage Nation and AMVEST Osage, Inc. (incorporated herein by reference to Exhibit 10.24 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.8	Assignment, Assumption and Ratification Agreement, dated as of July 25, 2007, by and between AMVEST Osage, Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 10.25 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.9	Water Gathering and Disposal Agreement, dated as of August 9, 1990, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.17 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.10	First Amendment to Water Gathering and Disposal Agreement, dated as of October 1, 1993, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.18 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File NO. 001-33147).
10.11	Second Amendment to Water Gathering and Disposal Agreement, dated as of November 30, 2004, by and between Robinson s Bend Operating Company, LLC and Everlast Energy LLC (incorporated herein by reference to Exhibit 10.19 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File NO. 001-33147).

Exhibit Number	Description
10.12	Third Amendment, dated June 13, 2011, to Water Gathering and Disposal Agreement dated November 30, 2004, by and between Robinson s Bend Operating II, LLC, Robinson s Bend Production II, LLC and Torch Energy Associates Ltd. (incorporated herein by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 15, 2011, File No. 001-33147).
10.13	Settlement and Release Agreement, effective as of June 13, 2011, by and among Trust Venture Company, LLC, Trust Acquisition Company, LLC, Wilmington Trust Company, Constellation Energy Partners LLC, Robinson s Bend Production II, LLC and Robinson s Bend Operating II, LLC (incorporated herein by reference to Exhibit 99.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 15, 2011, File No. 001-33147).
+10.14	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Stephen R. Brunner (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
+10.15	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Charles C. Ward (incorporated herein by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on November 6, 2009, File No. 001-33147).
+10.16	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Lisa J. Mellencamp (incorporated herein by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on November 6, 2009, File No. 001-33147).
+10.17	Employment Agreement, dated May 1, 2009, by and between CEP Services Company, Inc. and Michael B. Hiney (incorporated herein by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on November 6, 2009, File No. 001-33147).
+10.18	Constellation Energy Partners LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 20, 2006, File No. 001-33147).
+10.19	Constellation Energy Partners LLC 2009 Omnibus Incentive Compensation Plan (incorporated herein by reference to Exhibit A to the Proxy Statement filed by Constellation Energy Partners LLC on October 22, 2009, File No. 001-33147).
+10.20	Form of Grant Agreement Relating to Notional Units with DERs Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.9 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 4, 2009, File No. 001-33147).
+10.21	Form of Grant Agreement Relating to Notional Units with DERs Independent Managers (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.10 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 4, 2009, File No. 001-33147).
+10.22	Form of Grant Agreement Relating to Restricted Units Executives (under the 2009 Omnibus Incentive Compensation Plan incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on March 3, 2010, File No. 001-33147).
+10.23	Form of Amended and Restated Grant Agreement Relating to Unit-Based Awards Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on August 5, 2011, File No. 001-33147).
+10.24	Form of Grant Agreement Relating to Restricted Units Independent Managers (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.30 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 25, 2010, File No. 001-33147).

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Exhibit Number	Description
*12.1	Computation of Ratio of Earnings to Fixed Charges.
*21.1	List of subsidiaries of Constellation Energy Partners LLC.
*23.1	Consent of PricewaterhouseCoopers LLP.
*23.2	Consent of Netherland, Sewell & Associates, Inc.
*31.1	Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	Report of Netherland, Sewell & Associates, Inc.
**101.INS	XRBL Instance Document
**101.SCH	XRBL Schema Document
**101.CAL	XRBL Calculation Linkbase Document
**101.LAB	XRBL Label Linkbase Document
**101.PRE	XRBL Presentation Linkbase Document
**101.DEF	XRBL Definition Linkbase Document

* Filed herewith
\+ Management contract or compensatory plan or arrangement.