UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2010

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 ☐ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☑

(Do not check if a smaller reporting company)

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

Aggregate market value of Constellation Energy Partners LLC Common Stock, without par value, held by non-affiliates as of June 30, 2010 was approximately $57,972,310 based upon New York Stock Exchange 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 25, 2011: 23,835,303 units.

Documents Incorporated by Reference: None

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PART I

Item 1. Business

Overview

We are a limited liability company that was formed by Constellation Energy Group, Inc. ("Constellation") in 2005 to acquire oil and natural gas reserves. We are focused on the acquisition, development and production of oil and natural gas properties as well as related midstream assets. Our primary business objective is to create long-term value and to generate stable cash flows allowing us to resume making 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, 2010 were approximately 169.0 Bcfe, approximately 76% of which were classified as proved developed, and 98% of which are natural gas and 2% of which are oil. At December 31, 2010, we owned approximately 2,783 net producing wells. Our total average proved reserve-to-production ratio is approximately 11.5 years and our portfolio decline rate is 13 to 15 percent based on our estimated proved reserves at December 31, 2010 and production for the month ended December 31, 2010.

We completed our initial public offering on November 20, 2006 and our common units, representing Class B limited liability company interests, are listed on the NYSE Arca, Inc. 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 "successor company" or the "Company" means Constellation Energy Partners LLC and its subsidiaries. References in this Annual Report on Form 10-K to "CCG" and to "CEPM" are to Constellation Energy Commodities Group, Inc., and Constellation Energy Partners Management, LLC, respectively, each wholly-owned subsidiaries of Constellation.

Business Strategies

Our primary business objective is to create long-term value and to generate stable cash flows allowing us to resume making 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;
- reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient hedging programs;
- improve our liquidity position by reducing our outstanding debt level and actively managing our operating expenses; 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, which may include associated midstream assets such as gathering systems, compression, dehydrating and treating facilities and other similar facilities.

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, calculated before the Torch Royalty NPI, or NPI, described in Item 1. "Business—Operations—Torch Royalty NPI") in the Black Warrior Basin, which had 493 producing natural gas wells as of December 31, 2010.

Our properties in the Black Warrior Basin were first drilled in the early 1990s by Torch Energy Corporation ("Torch Energy") and its affiliates to take advantage of certain tax credits. Therefore, most of our wells were drilled before 1992. The properties in the Black Warrior Basin were owned and operated by Torch Energy until January 2003, when they were acquired by Everlast Energy LLC ("Everlast"), a company formed by a former Torch Energy executive. We acquired our initial properties in the Black Warrior Basin from Everlast in June 2005.

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.

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 Enterprise Alabama Intrastate, LLC pipeline ("Enterprise Alabama") from the Maxwell Crossing Module. Water produced from our wells is transferred via a facility pipeline to one of 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, 2010 were approximately 75.7 Bcfe, approximately 85% 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 adds moderate cash flow. In addition, there are other productive shale zones, as well as conventional sandstone and limestone potential that can add gas 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. Offsetting the 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.

At December 31, 2010, we own approximately 2,272 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, 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 wells operated by Bullseye Operating, L.L.C. 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, 2010 were approximately 88.2 Bcfe, approximately 66% of which were classified as proved developed and 97% of which were natural gas and 3% of which were oil.

Woodford Shale

The Woodford Shale is located in the Arkoma Basin in southern Oklahoma. We own 83 well bores, or approximately 10 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, 2010, our 83 wells have an average gross working interest of 11.4% and an average net revenue interest of 9.2%. 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, 2010 were approximately 4.3 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, 2010, we have a gross acreage position of 4,345 acres, or approximately 1,050 net acres and we own 36 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 usually 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 21.29% and the average net revenue interest is 17.16%.

Our estimated proved reserves in the Central Kansas Uplift at December 31, 2010 were approximately 0.8 Bcfe, approximately 91% 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:	2010	2009	2008
Estimated proved reserves:			
Oil (MBbl)	0.5	0.3	0.3
Natural gas (Bcf)	166.0	129.4	230.7
Total proved reserves (Bcfe)	169.0	131.2	232.4
Estimated proved developed reserves:			
Oil (MBbl)	0.4	0.3	0.3
Natural gas (Bcf)	124.9	110.3	157.2
Total proved developed reserves (Bcfe)	127.6	112.1	159.0
Estimated proved undeveloped reserves:			
Oil (MBbl)	0.1	0.0	0.0
Natural gas (Bcf)	41.1	19.1	73.4
Total proved undeveloped reserves (Bcfe)	41.4	19.1	73.4
Proved developed reserves as a percent of total reserves	76%	85%	68%
Standardized Measure (in millions) (a)	$131.7	$ 97.2	$228.9

(a) Standardized Measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (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 and debt service or to depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. Our Standardized Measure does not include future federal income taxes because we are not subject to federal income taxes. Standardized Measure does not give effect to derivative transactions and has no reserves attributable to the NPI. In 2009 the SEC adopted reserve reporting rules requiring that the Standardized Measure be calculated using an average 12-month price for 2010 and 2009 instead of a year-end price which was required to be used for 2008.

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. The reserve estimates for 2010 and 2009 were prepared using the SEC rules effective for the fiscal year ended December 31, 2009, which we further discuss on page 99.

At December 31, 2010, 2009, and 2008, 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 330 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 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, until 2020 and we have leasehold availability for our other proved undeveloped locations. Because of the increase in the SEC-required price from 2009 to 2010 utilized to determine our proved reserves, our 2010 reserve report now has proved undeveloped reserves recorded in the Cherokee Basin. During 2010, we did not develop the 10 proved undeveloped locations in the Black Warrior Basin that were included in our 2009 SEC reserve report. Instead, all our development drilling during 2010 occurred in the Cherokee Basin. During 2009, no proved undeveloped locations in the Cherokee Basin were recorded in our SEC reserve report because they were uneconomic at the SEC-required price. Our drilling decisions are not based on the SEC-required price. During 2011, we currently expect to drill 6 development wells in the Black Warrior Basin and 8 new wells in the Cherokee Basin.

The following table summarizes our inventory of proved undeveloped locations:

Year PUD Originally Booked		Year PUD Is Scheduled To Be Developed 2011	2012	2013	2014	2015
Total PUD Booked In Reserve Report	Number of Locations	31	112	94	74	70
	Equivalents-Bcfe	3.1	10.3	11.1	9.4	7.5
	Capital Estimate-$millions	$4.8	$16.0	$16.8	$14.0	$11.4

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.

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 Pipeline 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:

Market Prices:	Prices on January 1, 2011	2010	2009
Natural gas price—NYMEX (Henry Hub)	$ 4.22	$ 5.82	$ 6.16
Natural gas price—CenterPoint Energy Gas Transmission Co. (East)	$ 3.96	$ 5.67	$ 4.46
Natural gas price—Natural Gas Pipeline Co. of America (Midcontinent)	$ 3.96	$ 5.77	$ 4.66
Natural gas price—ONEOK Gas Transportation LLC (Oklahoma)	$ 4.10	$ 5.79	$ 4.61
Natural gas price—Panhandle Eastern Pipeline Co. (Texas, Oklahoma)	$ 3.93	$ 5.73	$ 4.57
Natural gas price—Southern Natural Gas Co. (Louisiana)	$ 4.27	$ 5.87	$ 6.21
Natural gas price—Southern Star Central Gas Pipeline Inc. (Texas, Oklahoma, Kansas)	$ 3.88	$ 5.79	$ 4.74
Oil price—West Texas Intermediate—Cushing	$91.38	$79.39	$44.60

We enter into derivative transactions in the form of hedging arrangements to reduce the impact of natural gas price volatility on our cash flow from operations. Currently, we use fixed price swaps and from time to time options to hedge New York Mercantile Exchange, or "NYMEX", 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. We currently do not have any oil hedges. By removing the price volatility from a significant portion of our natural gas production, we have mitigated, but not eliminated, the potential effects of fluctuating natural gas prices on our cash flow from operations for those periods. All of our derivative positions are outlined starting on page 70.

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, 2010	For the year ended December 31, 2009	For the year ended December 31, 2008
Net Production:			
Total production (MMcfe)	15,037	17,061	17,384
Average daily production (Mcfe/d)	41,197	46,742	47,497
Average Sales Prices:			
Price per Mcfe including hedges[a]	$ 10.03	$ 8.35	$ 9.39
Price per Mcfe excluding hedges	$ 4.54	$ 3.75	$ 8.13
Average Unit Costs Per Mcfe:			
Field operating expenses[b]	$ 2.26	$ 2.15	$ 2.57
Lease operating expenses	$ 2.05	$ 1.97	$ 2.09
Production taxes	$ 0.21	$ 0.18	$ 0.48
General and administrative expenses	$ 1.35	$ 1.08	$ 0.81
Depreciation, depletion and amortization	$ 5.67	$ 4.17	$ 3.01
Asset impairments	$ 18.12	$ 0.30	$ 1.47

(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.
(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		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
Volumes (MMcfe)	4,703	4,887	5,052	9,767	11,401	11,391	567	773	941
Sales Price per Mcfe, without hedges	$ 4.50	$ 4.07	$ 9.18	$ 4.52	$ 3.60	$ 7.61	$5.30	$3.60	$5.89
Lease Operating Expense per Mcfe	$ 1.51	$ 1.47	$ 1.45	$ 2.33	$ 2.19	$ 2.42	$1.58	$1.86	$1.36

Productive Wells

The following table sets forth information at December 31, 2010 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 production, 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, 2010		Oil December 31, 2010	
	Gross	Net	Gross	Net
Operated	2,345	2,291	134	134
Non-operated	797	330	96	28
Total	3,142	2,621	230	162

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, 2010, 2009 and 2008. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of oil or natural gas, regardless of whether they produce a reasonable rate of return. No exploratory wells were drilled during the years ended December 31, 2010, 2009 or 2008.

	Year Ended December 31,			Wells in Progress as of December 31,
	2010	2009	2008	2010
Gross:				
Development				
Productive	17	60	130	5
Dry	—	1	—	—
Recompletions	14	17	47	—
Total	31	78	177	5
Net:				
Development				
Productive	17	60	115	5
Dry	—	1	—	—
Recompletions	14	17	43	—
Total	31	78	158	5

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2010 relating to our leasehold acreage.

	Developed Acreage[(a)]		Undeveloped Acreage[(b)]	
	Gross[(c)]	Net[(d)]	Gross[(c)]	Net[(d)]
Total	263,439	247,866	34,517	29,556

(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.

This acreage includes areas leased under a concession agreement that we have with the Osage Nation in Osage County, Oklahoma, which provides us the exclusive right to lease up to approximately 560,000 acres within the Osage Nation. 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) wherein not less than 440 production wells shall be drilled and completed; (ii) Phase II (four year term of January 1, 2009 through December 31, 2012) wherein 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) wherein 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) wherein 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, 2008, the end of Phase I, we believe we have earned approximately 702 production well credits. As of December 31, 2009, we believe we have earned approximately 757 production well credits and our leased acreage totaled approximately 49,880 acres. As of December 31, 2010, we believe we have earned approximately 782 total developed and undeveloped production well credits and our total developed and undeveloped leased acreage totaled approximately 68,160 acres. Generally, we have the right each year to elect to license up to a certain acreage for that year for a specified license payment, and a license must be obtained before we lease acreage. During the term of the concession agreement, however, we have the exclusive right to lease the acreage covered thereunder unless we notify the Osage Nation in writing that we have no intention to lease any particular acreage. If the drilling requirement for a particular phase is not met, we have the option to make a payment equal to the shortfall of 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 shall be the termination of the concession agreement at the expiration of the then current phase, provided that such termination shall have no effect upon our wells already drilled and the leases that we have acquired that are producing in paying quantities.

Leases

Our leases are concentrated in Oklahoma (78%), Alabama (15%), and Kansas (7%). We have approximately 669 leases in the Black Warrior Basin on over 43,327 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 and the NPI. 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 calculated before the NPI. In some instances, our lease net revenue interest may be as high as 83%. We have approximately 1,650 leases in the Cherokee Basin on approximately 233,078 net acres. Our concession agreement with the Osage Nation in Osage County, Oklahoma provides us the exclusive right to lease approximately 560,000 net acres within the Osage Nation until its expiration in 2020 or any earlier termination according to its terms. 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 a gross acreage position of 4,345 acres in the Central Kansas Uplift, or approximately 1,050 net acres. We have no leasehold rights 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 20%, 9% and 3% of our total net undeveloped acreage of 29,556 acres is held under leases that have remaining primary terms expiring in 2011, 2012 and 2013, respectively. Of these expiration amounts in 2011, 2012, and 2013, approximately 88%, 79%, and 94%, respectively, apply to our concession agreement with the Osage Nation. If these leases do expire, we have the exclusive right to acquire a new 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. 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 87% of the 2,783 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, one of whom is currently our chief executive officer. 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 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.

Historically, when we drill new wells in the Black Warrior Basin, the drilling rigs are provided by and the wells are 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 executes 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 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 are provided by Falcon Field Services, Inc. and HS Field Services, Inc. The drilling rigs are provided by and our vertical wells are drilled by Pense Bros. Drilling Co., Inc. and our directional drilling is done by Scientific Drilling International, Inc. Other contract vendors conduct the cementing operations, provide well logging services and provide the design for, and executes upon, the well stimulation program. Rick’s Tank Truck Service is our primary water hauling service. We evaluate our service providers in the basin from time to time.

For our 83 well bores located in the Woodford Shale, the operators of the properties—primarily Devon and Newfield—conduct all operations on our behalf.

For our 36 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 for our assets 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, our project management team has 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 in both Alabama and Oklahoma, with our land administration function in Houston, Texas.

Revenue Accounting

Our revenue accounting function for all of our properties except for those in the Black Warrior Basin 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. It 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, receiving the revenues from oil and natural gas sales and providing accounting information used to generate financial statements.

Our revenue accounting function for our Black Warrior Basin properties has been outsourced to Petroleum Financial, Inc., a Texas-based revenue accounting firm. It manages the cash flow associated with our interest in our oil and natural gas properties, including the payment of invoices, calculation and payment of royalties, calculation and payment of the NPI, receiving the revenues from oil and natural gas sales and providing 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 Enterprise Alabama Intrastate, LLC. We currently sell our natural gas produced in the Cherokee Basin to Macquarie Energy LLC, Scissortail Energy, LLC, Cotton Valley Compression, L.L.C., 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. 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.

Hedging Activity

Our hedging activities are managed by our employees. Their activities are monitored by our risk committee composed of internal employees and quarterly risk reports are given 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 natural gas prices and interest rates and to achieve more predictable cash flows. We may enter into oil hedges to reduce our exposure to short-term fluctuations in oil prices. None of our derivatives require cash collateral and we do not enter into speculative or proprietary trading activities. For a more detailed discussion of our derivative activities, please read Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Item 7A. “Quantitative and Qualitative Disclosures about Market Risk” in this Annual Report on Form 10-K.

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 possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase properties and prospects 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 Constellation nor any of its affiliates is restricted from competing with us. Constellation or its affiliates may acquire, invest in or dispose of exploration and production properties or other assets without any obligation to offer us the opportunity to purchase or own interests in those assets.

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 the effects of 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

At the time we acquired our interests in our oil and natural gas properties, we obtained a title opinion or had performed 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 the oil and natural gas industry, we conducted 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 such property.

We believe that we have satisfactory title to all of our material assets. Although 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. The Trust Wells in the Robinson’s Bend Field in Alabama are subject to the NPI. For a more detailed discussion of the NPI, please read Item 1. “Business—Torch Royalty NPI”. 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 in all material respects as described in this Annual Report on Form 10-K.

Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, state and local 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 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, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

Environmental laws and regulations that could have a material impact on the oil and natural gas industry 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 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 Alabama Department of Environmental Management ("ADEM"). While we believe we are in substantial compliance with these permits and all 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.

Air Emissions

The Clean Air Act, and comparable state laws, regulate 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 for non-compliance with air permits or other requirements of the federal Clean Air Act and comparable state laws and regulations.

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 to 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 established liability for damages for injuries to, or loss of, natural resources.

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 the 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.

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, 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 is requiring the mandatory reporting of greenhouse gases from large sources of greenhouse gas emissions, with the first annual reports due by March 31, 2011. Our operations do not qualify us as a large source of greenhouse gas emission and we do not have a reporting requirement under that rule. However, under a final rule issued by the EPA in November 2010, we believe that it is likely that we will have a reporting requirement for greenhouse gases in 2011 and future years. Under the final rule, a reporting requirement arises for petroleum and natural gas systems when 25,000 metric tons of CO_2e or more per year in combined emissions are emitted from stationary fuel combustion units, miscellaneous uses of carbonate and, in our case, all equipment on wells pads and associated with well pads including compressors, generators or storage facilities, well drilling and completion equipment, and workover equipment. We believe that the reporting obligation will require us to measure, aggregate and report emissions on a basin-wide 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.

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, 2010, we had no accrued environmental obligations. We are not aware of any additional 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 December 31, 2010, our subsidiary, CEP Services Company, Inc., had 127 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.

Torch Royalty NPI

The NPI

The majority of our properties in the Robinson's Bend Field in the Black Warrior Basin are subject to a non-operating net profits interest ("NPI") held by Torch Energy Royalty Trust (the "Trust"). The NPI is a non-operating net revenue interest upon specified natural gas sales revenues from specified wells in the Black Warrior Basin (the "Trust Wells") reduced by specified associated expenditures. The units of the Trust are listed for trading on the New York Stock Exchange (the "NYSE"). An affiliate of Torch Energy conveyed the NPI to the Trust in November 1993, together with net profits interests on three other properties. We acquired our properties in the Robinson's Bend Field from Everlast subject to the NPI. The NPI conveyance gives the Trust an ownership interest in specified properties in the Robinson's Bend Field.

Not all of our wells within the Robinson's Bend Field are subject to the NPI. As of December 31, 2010, we owned a working interest in 493 producing wells in the Robinson's Bend Field, of which 424 were subject to the NPI as follows:

- with respect to 393 wells, the lesser of (i) 95% of the net proceeds from such wells for the quarter and (ii) the net proceeds from the sale of 912.5 MMcfe of natural gas for the quarter; and
- with respect to the remaining 31 wells that are subject to the NPI as of December 31, 2010, and all wells drilled thereafter on leases subject to the NPI other than wells drilled to replace damaged or destroyed wells, 20% of the net proceeds from such wells for the quarter. Net proceeds is defined under the NPI as gross revenue from the sale of production attributable to the NPI less specified development, operating and other costs and taxes, in each case as calculated under the NPI documentation. After January 1, 2004, lease operating expenses and capital expenditures have also been deducted in calculating net proceeds under the NPI on the Black Warrior Basin production. If permitted deductions exceed the gross revenue from the sale of production attributable to the NPI, the Trust is not entitled to a payment in respect of the NPI, and such excess, plus interest on such excess, is deducted from gross revenue attributable to future production in respect of the NPI. Payment of the net proceeds, if any, attributable to the NPI is made quarterly.
- No payments were made to the Trust in 2010, 2009, 2008 or 2007. In 2006, $0.2 million in payments to the Trust were made.

The Gas Purchase Contract

A gas purchase contract was executed in connection with the formation of the Trust in 1993, which established a minimum price for the purchase of the gas from the Trust Wells, as well as, a sharing arrangement when the applicable index price for gas increased over a specified sharing price. Torch Energy Marketing, Inc., an affiliate of the original sponsor of the Trust ("TEMI") as buyer, and another affiliate of TEMI, as seller, entered into the gas purchase contract pursuant to which the parties were obligated to purchase and sell, as the case may be, all net production attributable to the properties subject to the NPI, including the Trust Wells, for an amount equal to the greater of (a) the minimum price of $1.70 per MMBtu, adjusted for inflation, and (b) 97% of a specified index price for natural gas, less certain specified permitted deductions for gathering, treating and transportation that are calculated monthly. The index price for Black Warrior Basin production equals the SONAT Inside FERC price. In addition, if 97% of the index price exceeds the sharing price specified in the gas purchase contract as adjusted for inflation, which we refer to as the sharing price, the purchase price for the gas is equal to the sharing price plus 50% of the difference between 97% of the index price and the sharing price. As a result, the purchaser is entitled to retain 50% of that difference between 97% of the index price and sharing price. The sharing price was $2.43, $2.40, $2.30, $2.26, $2.22, and $2.18 per MMBtu in 2010, 2009, 2008, 2007, 2006, and 2005, respectively. Despite increases in spot prices for natural gas in certain years, the sharing arrangement under the gas purchase contract has had the effect of keeping the payments to the Trust significantly lower than if the NPI were calculated using the prevailing market price for production from the Trust Wells.

In connection with the acquisition of our initial properties in the Black Warrior Basin from Everlast, our subsidiary, Robinson's Bend Marketing II, LLC (now merged into our subsidiary Robinson's Bend Operating II, LLC), assumed TEMI's obligations under the gas purchase contract and our subsidiary, Robinson's Bend Production II, LLC ("RBP"), assumed the TEMI affiliate's obligations under the gas purchase contract, in each case in respect of the Black Warrior Basin for production from and after June 13, 2005. As a result, we were obligated to sell and to purchase all production from the Trust Wells on the terms and conditions set forth in the gas purchase contract until termination of the gas purchase contract on January 29, 2008.

Termination of the Trust and Gas Purchase Contract

On January 29, 2008, the unitholders of the Trust voted to terminate the Trust and the trust agreement and authorized the Trustee to wind up, liquidate and distribute the assets held by the Trust under the terms of the trust agreement. The gas purchase contract, by its terms, was also terminated on January 29, 2008 as a result of the termination of the Trust. With the gas purchase contract terminated, we are no longer obligated to sell gas produced from our interest in the Black Warrior Basin pursuant to the gas purchase contract. Notwithstanding the termination of the gas purchase contract, the NPI will continue to burden the Trust Wells, and it should continue to be calculated as if the gas purchase contract were still in effect, regardless of what proceeds may actually be received by us as the seller of the gas. As a result of the termination of the Trust, certain water gathering, separation and disposal costs, which are a component of the NPI calculation, increased from $0.53 per barrel to $1.00 per barrel pursuant to the Water Gathering and Disposal Agreement dated August 9, 1990, as amended; the amounts of the water gathering, separation and disposal costs are set forth in such agreement.

Litigation Related to Trust Termination

On January 25, 2008, Torch Royalty Company, Torch E&P Company, and CEP (collectively, the "Claimants") commenced an arbitration proceeding before Judicial Arbitration and Mediation Services against Wilmington Trust Company, as Trustee ("Trustee") for the Trust, and to Capital One, NA, as successor to Hibernia National Bank, as trustee for Torch Energy Louisiana Royalty Trust, pursuant to the operative dispute resolution provisions of the agreement governing the Trust, the NPI and the Conveyances (as defined below). The Claimants were working interest owners in certain oil and gas fields located in Texas, Louisiana and Alabama. The working interests owned by the other Claimants were similarly subject to net profit interests (the "Other NPIs") that were also based on the gas purchase contract. The Claimants sought a declaratory judgment that the NPI payments as well as the payments owed in respect of the Other NPIs will continue to be calculated using the sharing arrangement under the gas purchase contract even though the Trust and the gas purchase contract were terminated. The Trustee took the position that the sharing arrangement under the gas purchase contract terminated upon the termination of the gas purchase contract. Trust Venture Company, LLC ("Trust Venture") was permitted to intervene in the proceeding under an agreement whereby Trust Venture and its affiliates agreed to be bound by the formal award in the proceeding. On July 18, 2008, the arbitration panel issued its final award which, among other things, found and concluded that the sharing arrangement and other pricing terms of the gas purchase contract will continue to control the amount owed to the holder of the NPI, and on December 10, 2008, the District Court of Harris County, Texas, 152nd Judicial District, dismissed the appeal of the final award filed by the Trustee and Trust Venture and confirmed the final award.

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") demanding an audited statement of revenues and expenses associated with the NPI, alleging a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserting that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit seeks unspecified damages and an accounting of the NPI. The Court has made the Trust a nominal party to the Alabama litigation. On August 18, 2009, Trust Venture filed an application for preliminary injunction requesting that the Alabama court enter an injunction requiring the Company to deposit into an escrow account all fees, less expenses, that it receives from water disposal under the Water Gathering and Disposal Agreement pending judgment in the lawsuit and asserting damages of approximately $11.6 million from June 2005 to May 2009. These alleged damages appear to be calculated based on a water gathering, separation and disposal fee of $0.05 per barrel notwithstanding the provisions of the Water Gathering and Disposal Agreement. After hearing, the Court denied Trust Venture's application. On February 9, 2010, Trust Venture filed a motion for partial summary judgment seeking a determination regarding the applicability of a provision in the Conveyance related to the calculation of water handling charges, which motion the Court denied on May 28, 2010, with the Court ruling that our position with respect to the Conveyance provision was correct. At a preliminary hearing on February 17, 2011, the Court approved a form of notice of a settlement among the parties to be sent by the Trust to its unitholders. A final hearing on the settlement is set for April 11, 2011. No assurance can be made that the Court will approve settlement or that the Trust will sell the NPI to RBP II. The settlement with Trust Venture, its successor and the Trust provides, among other things:

- RBP II will make a payment of $1.2 million to reimburse Trust Venture and its successor for their legal fees and expenses incurred in prosecuting the lawsuit;
- RBP II will make an irrevocable offer to purchase the NPI relating to the Robinson's Bend Field from the Trust for at least $1 million, when it is separately offered for sale by the Trust at public auction within 180 days of the effective date of the settlement, with such bid amount to be deposited by RBP II in a third-party escrow account pending the public auction. RBP II, as well as any other bidders at the auction, shall have a right to submit a higher topping bid;
- The parties agree that the cumulative deficit balance in the NPI account is approximately $5.8 million as of September 30, 2010, and that no further payments will be due to the Trust with respect to the NPI unless and until the cumulative deficit balance is reduced to zero;
- Trust Venture and its successor agree, on behalf of the Trust, that all prior and current calculations, charges and deductions contained in such cumulative deficit NPI balance are in compliance with the terms of the Conveyance and, to the extent applicable thereunder, do not exceed competitive contract charges prevailing in the area for any such operations and services;
- The Water Gathering and Disposal Agreement between RBP II and another subsidiary of the Company will be amended to reduce the fee from $1.00 per barrel to $0.53 per barrel beginning on the first day of the month following the effective date of the settlement and to extend the term for an additional ten years, and Trust Venture and its successor agree, on behalf of the Trust, that the fees under such agreement do not exceed competitive contract charges prevailing in the area for the operations and services provided under such agreement during the extended term of such agreement;
- A mutual release among the parties and a dismissal with prejudice of the lawsuit; and
- An effective date of the settlement upon final approval by the Court.

Impact of Class D Interests

In order to address, to a limited extent, the risks of the potential adverse impact on our operating results from early termination, without the prior consent of our board of managers, of the sharing arrangement in respect of the calculation of amounts payable to the Trust for the NPI, Constellation Holdings, Inc. ("CHI") contributed to us at the closing of our initial public offering $8.0 million for all of our Class D interests. This contribution was to be returned to CHI in 24 special quarterly distributions over a period of approximately six years if the sharing arrangement remained in effect during that period. However, the special quarterly distributions with respect to the Class D interests were suspended beginning with the special quarterly distribution for the three months ending March 31, 2008. This suspension did not affect the special quarterly cash distribution paid to CHI, as holder of the Class D interests, on February 14, 2008 for the three months ended December 31, 2007. The remaining undistributed amount of the Class D interests is $6.7 million. If the amounts payable by us to the Trust are not calculated based on continued applicability of the sharing arrangement through December 31, 2012, unless such change is approved in advance by our board of managers and our conflicts committee, the following will occur: the Class D interest holder will cease receiving the special quarterly distributions; and the Class D interest holder will only receive the remaining undistributed amount of the original $8.0 million contribution under certain circumstances upon our liquidation. The effect of our retention and use of the unreturned amount is to provide us with cash that will mitigate, but may not eliminate, the adverse impact of our reduced revenues from the termination of the sharing arrangement.

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.

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, pipeline ruptures and discharges of toxic gases; fires; accidents or natural disasters; blowouts, craterings and explosions; and uncontrollable flows of natural gas or well fluids.

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

We ordinarily maintain insurance against 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 and 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 and production will decline, which 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.

Our production from our existing reserves will decline over time. To offset this decline, we must spend maintenance capital expenditures. During 2010, we spent less than our estimated 2010 maintenance capital expenditures of $25.3 million and our 2010 production decreased from 2009. We expect to spend between $10.0 million and $12.0 million in total capital expenditures in 2011, which is lower than our 2011 estimated maintenance capital expenditures of $23.0 million. Because we have spent less than our estimated maintenance capital expenditures in the past two years and expect to again spend less than our estimated maintenance capital expenditures in 2011, we would expect our production rates to further decline in 2011.

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 2010, 2009 and 2008, 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, 2010 would increase from approximately $131.7 million to approximately $246.9 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.

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. 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 and in the Woodford Shale. 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 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 natural gas. 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 Enterprise Alabama Intrastate, LLC. We currently sell our natural gas produced in the Cherokee Basin to Macquarie Energy LLC, Scissortail Energy, LLC, Cotton Valley Compression, L.L.C., 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. 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, 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.

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. If our leases expire, 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.

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 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 willingness and 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 carry on 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 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.

Our reserve-based credit facility matures on November 13, 2012 and, as a result, amounts due under the facility are scheduled to become a current liability on November 13, 2011. 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, together with, 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 from available cash 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 February 25, 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. We anticipate that at the time any future distribution is declared by our board of managers, our ability to pay distributions to our unitholders in any such quarter will be solely dependent on our ability to generate sufficient cash from our operations.

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 and our ability to fund maintenance capital expenditures and our ability to pay distributions.

Instability in the financial markets may affect the cost of capital, our ability to raise capital, and 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 failures of significant financial institutions 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 continuing to suspend distributions.

The 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.

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 further 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 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 would increase 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 and by the counterparties to our hedging arrangements. Some of our customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Despite our credit review and analysis, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our customers and/or counterparties 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 an 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;
- we will need a substantial portion of our cash flow 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 toward funding maintenance capital expenditures and other matters 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 an increase in inflation or stagflation, 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 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 reduction of outstanding debt balances and the establishment of cash reserves and the payment of fees and expenses.

Our quarterly distribution rate has been suspended in order to remain in compliance with the covenants associated with our reserve-based credit facility. In order for us to make a distribution from available cash our outstanding debt balances, net of available cash, must be less than 90% of our borrowing base as determined by our lenders. 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 2012 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 our 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 do not continue to reduce our outstanding debt levels, we may not be able to resume quarterly distributions, which may cause the market price of our common units to decline substantially.

In addition, 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; 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.

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; 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 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, any management incentive interests and Class D interests. As a result of these factors, we may not have sufficient available cash to resume, maintain or increase our quarterly distributions. Even if we were able to resume a quarterly cash distribution, 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 the quarterly distribution amount of $0.13 per unit that we paid for the first quarter 2009. 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, and if commodity prices decline significantly for a temporary or prolonged period, our cash from operations will decline and we may have to lower any quarterly distribution or may not be able to pay distributions at all.

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 new 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 sustained lower commodity prices.

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 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 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 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. We currently have no oil hedges, but may have some in the future. 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, resulting 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 because we are:

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

In any 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 Relationship with Constellation

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

Constellation indirectly owns approximately 24.8% of the outstanding common units and 100% of the outstanding Class A units as of February 25, 2011. The percentages reflect common units that have been issued under our unit-based compensation programs. CEPM, as the holder of all our Class A units, has the exclusive right to elect two members of our board of managers. As of February 25, 2011, CEPH controlled an aggregate of 5,918,894 common units. These units have been registered for resale at the request of CEPH. Constellation has previously announced that it has impaired its value of its investment in CEP for various reasons, including the possible sale of its investment. If CEPH were to sell some or a substantial portion of its common units, it could reduce the market price of our outstanding common units.

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

Constellation's affiliates may transfer their Class A units, common units, 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 Constellation to cause a transfer to a third party of all or any portion of its affiliates' equity interests in CEPM, CEPH, or CHI.

Members of our board of managers, our executive officers and Constellation and its affiliates, including CEPH and CEPM, 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. As of February 25, 2011, one of the members appointed by CEPM is a contractor retained by Constellation and the other member appointed by CEPM is our chief executive officer, chief operating officer, and president. Conflicts of interest may arise between us and our unitholders and members of our board of managers or our executive officers or Constellation and its affiliates, including CEPH and CEPM. These potential conflicts may relate to the divergent interests of these parties. Situations in which the interests of members of our board of managers or our executive officers or Constellation and its affiliates, including CEPH and CEPM, 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 Constellation, CEPM or any of their affiliates to pursue a business strategy that favors us. Directors and officers of Constellation, CEPM and their subsidiaries (other than us) have a fiduciary duty while acting in the capacity as such a director or officer of Constellation, CEPM or such subsidiary to make decisions in the best interests of the Constellation stockholders, which may be contrary to our best interests;
- neither Constellation nor CEPM 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;
- one of our managers is not being compensated by us; instead, he is being compensated by Constellation for serving as a contractor of Constellation;
- none of our executive officers or the members of our board of managers or Constellation and its affiliates, including CEPH and CEPM, 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 Constellation or CEPM, 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 the 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 Constellation 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 and CEPM, the holder of our Class A units, will have the right to convert its management incentive interests into common units based on the then fair market value of such interests, which may be dilutive to the common unitholders.

Our limited liability company agreement prohibits a unitholder (other than CEPM, CEPH and their affiliates) 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 could discourage a change of control that our unitholders may favor, which could negatively affect the price of our common units.

Our limited liability company agreement effectively adopts Section 203 of the Delaware General Corporation Law (the “DGCL”). Section 203 of the DGCL as it applies to us prevents 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. 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. 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.

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 Constellation, CEPM, their affiliates or transferees and persons who acquire such units with the prior approval of the 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 (the Delaware 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 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;
- the borrowing base of our reserve-based credit facility as determined by our lenders in their sole discretion;
- changes 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 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 distributions from us. Generally, should we generate taxable income for a particular tax year and not pay any 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 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 2010, we did not pay any distributions on any common unit (or Class B) or Class A unit. If we generate taxable income for the 2010 tax year, our unitholders and any unitholders who purchase or purchased common units did not receive distributions from us during 2010 sufficient to pay any actual tax liability that results from their share of such 2010 taxable income. Additionally, based on our 2011 business plan and forecast, we do not currently anticipate resuming a cash distribution in 2011 and we anticipate making limited maintenance capital expenditures. If we generate taxable income for the 2011 tax year, our unitholders may not receive distributions from us during 2011 in an amount sufficient to pay the actual tax liability that results from their share of such 2011 taxable income.

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 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 technically terminated for tax purposes for the 2009 tax year and incurred additional costs as a result of the termination. We are not able to control or to predict if or when we may technically terminate for tax purposes in the future.

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 will 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.

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 the 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.

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.

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, the treatment and disposal of produced water, and the regulation of commodity derivatives. The EPA has also officially 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 may also impact our ability to enter into derivatives or require burdensome 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 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 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; and
- the CERCLA, also known as “the Superfund law,” 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.

- 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.

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 and local 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.

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, 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.

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 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 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 the NPI

The formula in the gas purchase contract on which the NPI is based contains a minimum price arrangement, which could have the effect of requiring a higher royalty payment in respect of the NPI than would be the case if the gas purchase contract did not have the minimum price arrangement. If the applicable index price falls below the minimum price, it could adversely affect our financial condition and results of operations and, as a result, our ability to pay distributions.

Pursuant to the formula in the terminated gas purchase contract on which the NPI is based, we are required to pay at least $1.70 (adjusted for inflation annually) per MMBtu, which we refer to as the minimum price, for production sold in respect of the Trust Wells. If the applicable index price is less than the minimum price in any month, amounts payable for production sold in respect of the Trust Wells could be higher than the gross proceeds we would receive for the gas at market prices. As a result, the royalty obligation payable by us in respect of the NPI could exceed the gross proceeds we have received for the gas produced in respect of the NPI. If we have to pay a royalty under the NPI based upon the minimum price that exceeds the actual revenue received by us for the sale of such gas, based upon market prices, it could adversely affect our financial condition and results of operations and, as a result, our ability to pay distributions. The index price for the Trust Wells is the price reported in *Inside FERC's Gas Market Report* for the Southern Natural Gas Co., Louisiana Hub, which we refer to as the SONAT Inside FERC price.

The formula in the gas purchase contract on which the NPI is based contains a sharing arrangement in the event the applicable spot index price for natural gas exceeds the sharing price, as calculated under the gas purchase contract. If the applicable spot index price for natural gas falls below the sharing price, it would have the effect of reducing the revenue we retain upon sale of the gas produced from the Trust Wells and could adversely affect our financial condition and results of operations and, as a result, our ability to pay distributions.

The formula in the terminated gas purchase contract on which the NPI is based provides for a sharing arrangement in the event the index price in any month exceeds a price of $2.10 (adjusted for inflation annually, or $2.43 for 2010, $2.40 for 2009, $2.30 for 2008, $2.26 for 2007, and $2.22 for 2006) per MMBtu, which we refer to as the sharing price. If 97% of the applicable spot index price is equal to or less than the sharing price, the royalty obligation payable by us in respect of the NPI is calculated at the greater of (i) 97% of the index price per MMBtu and (ii) the minimum price described in the immediately preceding risk factor. If the index price exceeds the sharing price in any month, however, the royalty obligation payable by us in respect of the NPI is calculated at the sharing price plus 50% of the excess of 97% of the applicable spot index price over the sharing price per MMBtu. In that case, the calculation of gross proceeds in the NPI calculation could be substantially less than the gross proceeds at market prices, as a result of which the royalty obligation payable by us in respect of the NPI could be substantially less than the gross proceeds we have received for the produced gas. If the index price is equal to or less than the sharing price, it could adversely affect our financial condition and results of operations and, as a result, our ability to pay distributions.

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 credit facilities 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 distribution;
- the impact from any termination of the NPI sharing arrangement or any change in the calculation of the NPI or whether the court will approve the derivative lawsuit settlement relating to the NPI;
- 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;
- support from our former 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," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Annual Report on Form 10-K are largely based on 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—Financing Activities—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

Termination of the Trust and Related Litigation

On January 29, 2008, the unitholders of the Torch Energy Royalty Trust voted to terminate the Trust and authorized the Trustee to wind up, liquidate, and distribute the assets held by the Trust under the terms of the trust agreement. As discussed in Item 1. “Business” on page 1 and Item 1A. “Risk Factors” on page 19, we are involved in litigation related to the calculation of the NPI held by the Trust in the Robinson’s Bend Field in Alabama.

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

Item 4. Reserved

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 Arca under the symbol "CEP." On February 24, 2011, there were 23,835,303 common units outstanding and approximately 5,400 unitholders. On February 24, 2011, the market price for our common units was $2.75 per unit, resulting in an aggregate market value of units held by non-affiliates of approximately $49.2 million. The following table presents the high and low closing price for our common units during the periods indicated.

	Common Stock	
	High	Low
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
2009		
First Quarter	$4.51	$1.52
Second Quarter	$4.37	$1.52
Third Quarter	$4.12	$2.13
Fourth Quarter	$4.34	$3.23

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 2010 and the second, third and fourth quarters of 2009.

Subject to the terms of our reserve-based credit facility, which is discussed further on page 66, our limited liability company agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ended December 31, 2006, 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 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.

Private Placements

There were no private placement transactions in 2010, 2009 and 2008.

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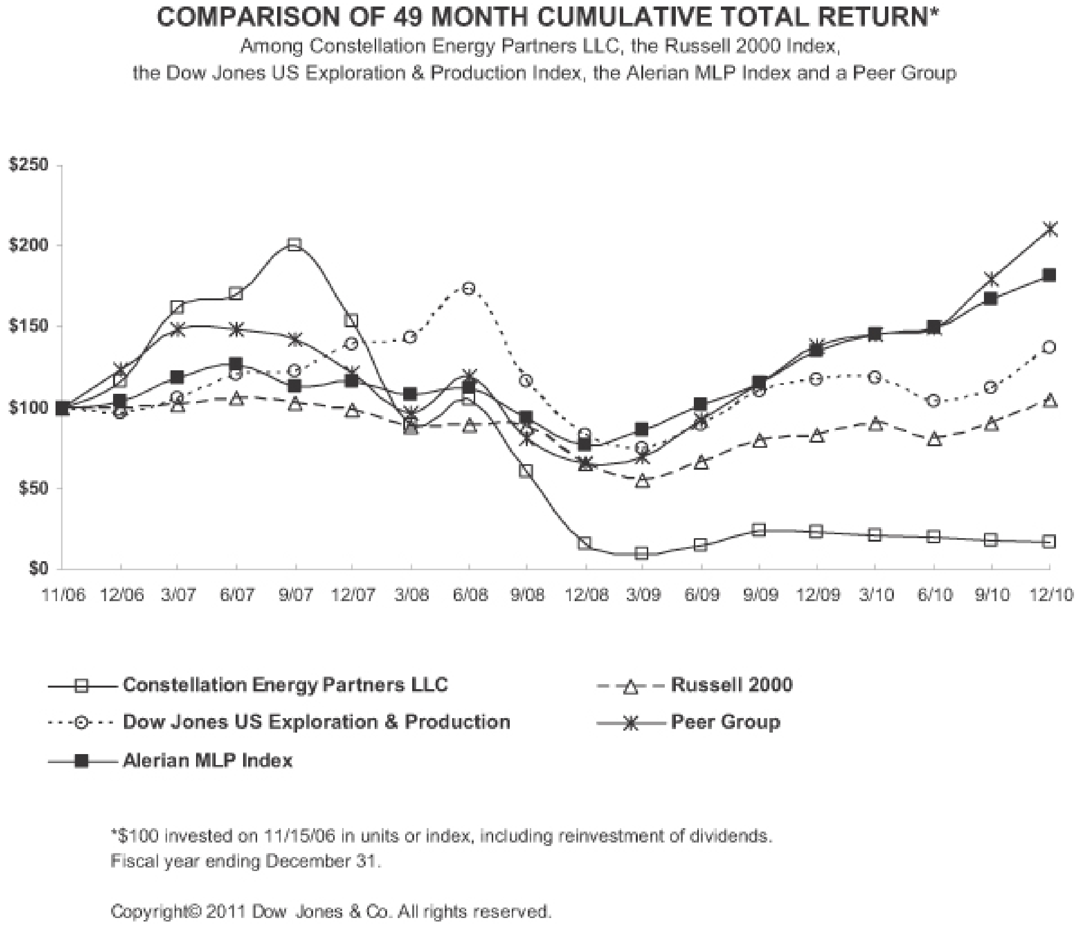
Common Unit Performance Graphs

The graph below matches the cumulative 49-month total return of holders of our common units with 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 Limited Partner, EV Energy Partners Limited Partnership, Legacy Reserves Limited Partnership, Linn Energy Limited Liability Company, Pioneer Southwest Energy Partners Limited and Vanguard Natural Resources LLC. The graph assumes that the value of the investment in the our common units, in each index, and in the peer group (including reinvestment of dividends) was $100 on November 15, 2006 and tracks it through December 31, 2010.



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

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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.

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, 2010	For the year ended December 31, 2009	For the year ended December 31, 2008	For the year ended December 31, 2007	For the year ended December 31, 2006
			(in 000's)		
Statement of Operations Data:					
Revenues:					
Oil and gas sales	$ 108,692	$ 123,126	$ 141,863	$ 82,725	$ 36,917
Gain (Loss) from mark-to-market activities	42,081	19,410	21,376	(6,856)	—
Total revenues	150,773	142,536	163,239	75,869	36,917
Operating expenses:					
Lease operating expenses	30,798	33,535	36,257	17,141	7,234
Cost of sales	2,473	2,638	7,261	1,788	—
Production taxes	3,179	3,153	8,398	3,646	1,783
General and administrative expenses	20,351	18,506	13,998	8,789	4,263
Exploration costs	760	855	414	320	310
Depreciation, depletion and amortization	85,263	71,173	52,281	23,190	7,444
Asset impairments	272,487	5,113	25,638	—	—
Accretion expense	822	406	411	312	141
(Gain)/Loss on sale of assets	(18)	—	(301)	86	—
Total operating expenses	416,115	135,379	144,357	55,272	21,175
Other expenses/(income):					
Interest expense	12,721	11,967	12,167	6,930	221
Interest expense (Gain)/Loss from mark-to-market activities	(765)	4,338	—	—	—
Interest income	(3)	(2)	(350)	(465)	(468)
Other (income) expense	(385)	(123)	(203)	(109)	—
Total other expenses (income)	11,568	16,180	11,614	6,356	(247)
Total expenses	427,683	151,559	155,971	61,628	20,928
Net income (loss)	$ (276,910)	$ (9,023)	$ 7,268	$ 14,241	$ 15,989
Earnings (Loss) per unit					
Basic	$ (11.36)	$ (0.40)	$ 0.32	$ 0.87	$ 1.41
Diluted	$ (11.36)	$ (0.40)	$ 0.32	$ 0.87	$ 1.41
Distributions declared and paid per unit	$ —	$ 0.26	$ 2.25	$ 1.6986	$ —
Other Financial Information (unaudited):					
Adjusted EBITDA	$ 54,125	$ 66,992	$ 75,285	$ 52,840	$ 23,335

	Constellation Energy Partners LLC				
	For the year ended December 31, 2010	For the year ended December 31, 2009	For the year ended December 31, 2008	For the year ended December 31, 2007	For the year ended December 31, 2006
			(in 000's)		
Balance Sheet Data:					
Cash and cash equivalents	$ 7,892	$ 11,337	$ 6,255	$ 18,689	$ 7,485
Other current assets	45,199	33,928	45,976	27,184	18,602
Oil and natural gas properties, net of accumulated depreciation, depletion and amortization	276,919	612,625	662,519	643,653	171,639
Other assets	54,367	50,427	44,099	17,129	5,971
Total assets	$ 384,377	$ 708,317	$ 758,849	$ 706,655	$ 203,697
Current liabilities	$ 14,533	$ 16,484	$ 19,506	$ 20,551	$ 9,007
Debt	165,000	195,000	212,500	153,000	22,000
Other long-term liabilities	13,024	12,129	6,754	16,702	2,730
Class D interests	6,667	6,667	6,667	7,000	8,000
Members equity:					
Common members equity	174,233	449,670	463,295	505,178	148,847
Accumulated other comprehensive income	10,920	28,367	50,127	4,224	13,113
Total members' equity	185,153	478,037	513,422	509,402	161,960
Total liabilities and members' equity	$ 384,377	$ 708,317	$ 758,849	$ 706,655	$ 203,697
Cash Flow Data:					
Net cash provided by operating activities	$ 40,829	$ 56,087	$ 75,632	$ 42,499	$ 14,067
Net cash used in investing activities	(13,766)	(22,571)	(95,008)	(502,533)	(25,429)
Net cash provided by (used in) financing activities	(30,508)	(28,434)	6,942	471,238	4,016
Development of natural gas properties	(7,973)	(22,913)	(47,897)	(23,645)	(13,224)

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;
- unrealized (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.

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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, 2010	For the year ended December 31, 2009	For the year ended December 31, 2008	For the year ended December 31, 2007	For the year ended December 31, 2006
			(In 000's)		
Reconciliation of Net Income (Loss) to Adjusted EBITDA:					
Net income (loss)	$ (276,910)	$ (9,023)	$ 7,268	$ 14,241	$ 15,989
Adjusted by:					
Interest (income) expense, net	11,953	16,303	11,817	6,465	(247)
Depreciation, depletion and amortization	85,263	71,173	52,281	23,190	7,444
Asset impairments	272,487	5,113	25,638	—	—
Accretion expense	822	406	411	312	141
(Gain)/Loss on sale of assets	(18)	—	(301)	86	—
Exploration costs	760	855	414	320	310
(Gain)/Loss on mark-to-market activities	(42,081)	(19,410)	(21,376)	6,856	—
Unit-based compensation programs	1,849	1,308	322	145	—
Unrealized loss/(gain) on derivatives/hedge ineffectiveness	—	267	(1,189)	1,225	(302)
Adjusted EBITDA	$ 54,125	$ 66,992	$ 75,285	$ 52,840	$ 23,335

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.

Overview

We are a limited liability company formed by Constellation Energy Group, Inc. ("Constellation") on February 7, 2005 to acquire oil and natural gas properties as well as related midstream assets. At December 31, 2010, our oil and natural gas reserves were located in the Black Warrior Basin of Alabama, in the Cherokee Basin of Kansas and Oklahoma, in the Woodford Shale in Oklahoma, and the Central Kansas Uplift in Kansas and Nebraska. Our primary business objective is to create long-term value and to generate stable cash flows allowing us to resume making 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;
- reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient hedging programs;
- improve our liquidity position by reducing our outstanding debt level and actively managing our operating expenses; 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, which may include associated midstream assets such as gathering systems, compression, dehydrating and treating facilities and other similar facilities.

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 our current reserves and economically finding, developing and acquiring additional recoverable reserves. We may not be able to find, develop or acquire additional reserves to replace our current and future production at acceptable costs, which could materially adversely affect our business, financial condition and results of operations and our ability to pay quarterly distributions to our unitholders.

We also face the challenge of oil and natural gas production declines. As a given well's initial reservoir pressures are depleted, oil and natural gas production decreases. We attempt to overcome this natural decline in production by drilling additional wells on our proven undeveloped, probable and possible locations on our existing properties and by acquiring additional reserves when opportunities arise. We will continue to focus on adding reserves through drilling, well recompletions and right-sized acquisitions, as well as the corresponding costs necessary to produce such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. In accordance with our business plan, we intend to invest the capital necessary to maintain our production and our asset base over the long term. We seek to maintain or grow our production and our asset base by pursuing both organic growth opportunities and acquisitions of producing oil and natural gas reserves that are suitable for us.

We completed our initial public offering on November 20, 2006, and our common units, representing Class B limited liability company interests, are listed on the NYSE Arca, Inc. under the symbol "CEP."

Since our formation in 2005, we have expanded our operations by entering into six separate definitive purchase agreements to acquire certain oil and natural gas properties 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. These acquisitions provide us the opportunity to organically grow our business by drilling unproved locations acquired primarily in Osage County, Oklahoma.

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

During the third quarter of 2010, due to a significant decline in future natural gas price curves across all future production periods, we performed an impairment analysis of our oil and natural gas properties and other non-current assets. As a result of this analysis, we recorded a total non-cash asset impairment charge of $272.5 million. The impairment was caused by the impact of lower future expected natural gas prices. This non-cash asset impairment charge lowered our net income to a loss for the year but it did not impact our Adjusted EBITDA, cash flows, liquidity position, or debt covenants. The impairment is further discussed on pages 56 and 112.

Significant Operational Factors

- *Realized Prices.* Our average realized price for the twelve months ended December 31, 2010, including hedges, was $10.03 per Mcfe. This realized price includes the impact of $42.1 million of unrealized gains on mark-to-market derivatives. Excluding the impact of the unrealized mark-to-market gains, the average realized price for the twelve months ended December 31, 2010 was $7.23 per Mcfe. Further deducting the cost of sales associated with third party gathering, average realized prices were $7.06 per Mcfe including hedges and $4.38 per Mcfe excluding hedges.
- *Production.* Our production during 2010 was approximately 15.0 Bcfe, or an average of 41,197 Mcfe per day. This level of production was lower than our 2009 production of 17.1 Bcfe and 2008 production of 17.4 Bcfe. Our production has declined because our capital spending in 2010 was below the maintenance capital expenditures required to offset the natural production declines associated with our existing wells.
- *Capital Expenditures and Drilling Results.* During 2010, we spent approximately $14.3 million in cash capital expenditures. Of this amount, $7.9 million was primarily for development activities in the Cherokee Basin and $6.4 million was for acquisitions of new properties. This level of spending was below our 2010 maintenance capital budget of approximately $25.3 million. This maintenance capital budget is intended to maintain our production rates, reserves, and asset base. Because we spent less than our maintenance capital budget in 2010, we would expect our production to continue to decline in 2011.

  In the Black Warrior Basin, we stopped drilling activities in 2010 due to low natural gas prices and the estimated costs to drill and complete wells in the basin. We have an inventory of 9 completed drilling locations which cost approximately $1.2 million. We expect to drill on some of these locations during 2011.

In the Cherokee Basin, we drilled and completed 17 net wells and performed 14 net recompletions. As of February 25, 2011, we have 5 net wells which require completion.

Because of our 2010 drilling program in the Cherokee Basin and our acquisition of non-operated oil properties in the Central Kansas Uplift, we were able to increase our oil reserves and our oil production. While both our oil reserves and oil production remain a small part of our current operations on a relative basis, year-on-year our daily average gross oil production increased from approximately 185 barrels per day in December 2009 to 355 barrels per day in December 2010.

We will continue to evaluate the total costs, and the timing of such costs associated with our drilling programs, in light of our liquidity position, current oil and natural gas prices, and anticipated service costs. We will also continue to focus on completing right-sized acquisitions of oil and natural gas reserves.

- *Oil and Natural Gas Reserves.* Our total year end 2010 proved reserves were 169.0 Bcfe which is 37.8 Bcfe higher than our year end 2009 proved reserves of 131.2 Bcfe. Our 2010 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 2010 estimates of proved reserves increased from 2009 primarily due to reserve revisions as a result of a higher SEC-required 12-month average price for natural gas compared to 2009 and our 0.8 Bcfe acquisition of oil reserves in the Central Kansas Uplift. This price increase resulted in the recording of 30.2 Bcfe in proved undeveloped reserves in the Cherokee Basin because they became economic to develop at the 2010 SEC-required price. We removed 8.0 Bcfe of the total proved undeveloped reserves that existed in the Black Warrior Basin in 2009 because of approximately $3.0 million in lower estimated capital being deployed in the last four years of our five year plan. 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 98% 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 natural gas price used to prepare our reserve report was $4.55 in the Black Warrior Basin and $3.98 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 25, 2011, we have successfully reduced our outstanding debt level from a high of $220.0 million to $165.0 million. During 2011, we intend to continue to use our excess operating cash flows to continue to reduce our outstanding debt by an additional $25.0 million to $30.0 million. As of February 25, 2011, our reserve-based credit facility has a borrowing base of $195.0 million, which currently leaves us with $30.0 million of funds available for borrowing.
- *Hedging Activities*. As of December 31, 2010, all of our swaps and basis swaps are accounted for as mark-to-market derivatives. 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 mark-to-market gain of $19.4 million for the same period in 2009.

We experience earnings volatility as a result of using the mark-to-market accounting method for all of our commodity derivatives used to hedge our exposure to changes in commodity prices or basis differentials. This accounting treatment can cause earnings volatility as the positions for future oil and natural gas production 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. We do not enter into speculative trading positions and we only use derivatives to lock in the future sales price for a portion of our expected oil and natural gas production. Increases in the market price of oil or natural gas relative to the fixed future sales price 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 relative to the fixed future sales price 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 commodity sale is not marked-to-market and therefore is not reflected as Oil and Gas Sales or as an Accounts Receivable in our financial statements. This mismatch impacts our reported Results of Operations and our reported working capital position until the commodity derivatives are cash settled and the oil and natural gas is produced and sold. Upon cash settlement of the derivatives, the sale of the physical commodity 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 at the fixed future sales price for our hedge. When our derivative positions are cash settled as the related commodities are produced and sold, the realized gains and losses of those derivative positions are included in our Statement of Operations as Oil and Gas Sales. Further detail of our commodity derivative positions and their accounting treatment is outlined starting on page 70.

- *Asset Impairments.* For the year ended December 31, 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 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 located in the Woodford Shale, and $0.5 million to impair the value of our casing inventory. These non-cash charges are included in asset impairments in the Consolidated Statement of Operations. These impairments were recorded because the net capitalized costs of the assets exceeded the fair value of the assets as measured by estimated cash flows based upon future oil and natural gas prices. These impairments were caused by the impact of lower future expected natural gas prices. During the third quarter of 2010, future natural gas price curves shifted significantly lower, especially in the years 5 through 15. These impairments reflect the price sensitivity and long-term nature of our coalbed methane reserves base. Cash flow estimates for the impairment testing exclude derivative instruments used to mitigate the risk of lower future natural gas prices. These asset impairments have no impact on our operations, Adjusted EBITDA, cash flows, liquidity position, or debt covenants.
- *Torch Royalty NPI Litigation Settlement*. We have entered into a settlement agreement with the parties to the Torch derivative action litigation, subject to the approval of the Court. The settlement agreement generally provides for (i) a settlement of all claims in the lawsuit and a mutual release of all claims among the parties through the effective date of the settlement, (ii) an agreement as to the cumulative deficit balance in the NPI account through September 30, 2010 of approximately $5.8 million, (iii) an amendment to the Water Gathering and Disposal Agreement to establish a $0.53 per barrel fee for a ten year period from the first of the month following the effective date of the settlement, (iv) payment by RBP II of $1.2 million to reimburse Trust Venture for its fees and expenses in prosecuting the lawsuit, and (v) an irrevocable offer by RBP II to purchase the NPI from the Trust for $1.0 million in an auction of the NPI by the Trust, subject to the Trust auctioning the NPI within 180 days of the effective date of the settlement, with the purchase price to held in escrow. A preliminary hearing was held on the settlement on February 17, 2011, where the Court approved the form of notice regarding the settlement to the unitholders of the Trust, and the final hearing on the settlement has been set by the Court for April 11, 2011. Because the NPI was granted to the Trust by a predecessor-in-interest to RBP II, if RBP II is the winning bidder in the auction of the NPI by the Trust, we would expect the NPI to be extinguished once the NPI is assigned to RBP II by the Trust. If the Trust sells the NPI to another party, the Water Gathering and Disposal Agreement would have a fee of $0.53 a barrel for an additional 10 year term from the first day of the month following the effective date of the settlement. If we had calculated the NPI for the fourth quarter 2010 with the prevailing gas prices during the quarter and the $0.53 a barrel water gathering and disposal fee, the cumulative deficit balance would have grown to larger than the approximately $5.8 million balance through September 30, 2010.

Significant Market Factors

- *Relationship with our Former Sponsor.* Constellation still owns all of our outstanding Class A units, approximately 5.9 million Class B common units, all of our Class D interests, and all of the Management Incentive Interests. Constellation terminated the management services agreement with us on December 15, 2009. All the services that Constellation previously performed have been transitioned to us. This termination effectively ended Constellation's tenure as our sponsor and we do not expect Constellation to provide us with any significant services, support, financing, or acquisition opportunities in the future.

  Constellation previously announced that it had impaired the fair value of its investment in us due to various factors, including the possible sale of its investment in CEP. To date no further public announcements have been made. We recognize that there may be the potential for downward pressure on our unit price when a large unitholder makes an announcement such as this. We continue to look for a way to address this issue.

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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, 2010	For the year ended December 31, 2009	2010 Vs 2009 Variance $	2010 Vs 2009 Variance %	For the year ended December 31, 2008	2009 Vs 2008 Variance $	2009 Vs 2008 Variance %
Revenues:							
Oil and gas sales	$ 108,692	$ 123,126	(14,434)	(11.7)%	$ 141,863	(18,737)	(13.2)%
Gain (Loss) from mark-to- market activities	42,081	19,410	22,671	116.8%	21,376	(1,966)	(9.2)%
Total revenues	150,773	142,536	8,237	5.8%	163,239	(20,703)	(12.7)%
Operating expenses:							
Lease operating expenses	30,798	33,535	(2,737)	(8.2)%	36,257	(2,722)	(7.5)%
Cost of sales	2,473	2,638	(165)	(6.3)%	7,261	(4,623)	(63.7)%
Production taxes	3,179	3,153	26	0.8%	8,398	(5,245)	(62.5)%
General and administrative expenses	20,351	18,506	1,845	10.0%	13,998	4,508	32.2%
Exploration costs	760	855	(95)	(11.1)%	414	441	106.5%
(Gain) loss on sale of assets	(18)	—	(18)	—	(301)	301	(100.0)%
Depreciation, depletion and amortization	85,263	71,173	14,090	19.8%	52,281	18,892	36.1%
Asset impairments	272,487	5,113	267,374	5,229.3%	25,638	(20,525)	(80.1)%
Accretion expenses	822	406	416	102.5%	411	(5)	(1.2)%
Total operating expenses	416,115	135,379	280,736	207.3%	144,357	(8,978)	(6.2)%
Other expenses (income):							
Interest expense	12,721	11,967	754	6.3%	12,167	(200)	(1.6)%
Interest expense (Gain)/loss from mark-to-market activities	(765)	4,338	(5,103)	(117.6)%	—	(4,338)	—
Interest income	(3)	(2)	(1)	50.0%	(350)	348	(99.4)%
Other (income) expense	(385)	(123)	(262)	213.0%	(203)	80	(39.4)%
Total other expenses (income)	11,568	16,180	(4,612)	(28.5)%	11,614	4,566	39.3%
Total expenses	427,683	151,559	276,124	182.2%	155,971	(4,412)	(2.8)%
Net income (loss)	$ (276,910)	$ (9,023)	$(267,887)	2,968.9%	$ 7,268	$(16,291)	(224.1)%
Net production:							
Total production (MMcfe)	15,037	17,061	(2,024)	(11.9)%	17,384	(323)	(1.9)%
Average daily production (Mcfe/d)	41,197	46,742	(5,545)	(11.9)%	47,497	(755)	(1.6)%
Average sales prices:							
Price per Mcfe including hedges[a]	$ 10.03	$ 8.35	$ 1.68	20.1%	$ 9.39	$ (1.04)	(11.0)%
Price per Mcfe excluding hedges	$ 4.54	$ 3.75	$ 0.79	21.1%	$ 8.13	$ (4.38)	(53.9)%
Average unit costs per Mcfe:							
Field operating expenses[b]	$ 2.26	$ 2.15	$ 0.11	5.1%	$ 2.57	$ (0.42)	(16.3)%
Lease operating expenses	$ 2.05	$ 1.97	$ 0.08	4.1%	$ 2.09	$ (0.12)	(5.8)%
Production taxes	$ 0.21	$ 0.18	$ 0.03	16.7%	$ 0.48	$ (0.30)	(62.5)%
General and administrative expenses	$ 1.35	$ 1.08	$ 0.27	25.0%	$ 0.81	$ 0.27	33.3%
General and administrative expenses w/o unit-based compensation	$ 1.23	$ 1.01	$ 0.22	21.8%	$ 0.79	$ 0.22	27.8%
Depreciation, depletion and amortization	$ 5.67	$ 4.17	$ 1.50	36.0%	$ 3.01	$ 1.16	38.5%

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

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 a $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.

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.

Hedging and 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 do not expect future volumes to exceed the hedged volumes that had been accounted for previously as cash flow hedges.

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.

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.

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, and 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 volume.

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 litigation surrounding the NPI, $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 the management services agreement 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 and 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.

Depreciation, depletion and amortization expense and asset impairments. Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs and asset impairment expense 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 composed of higher depletion expense. The increase in 2010 depreciation, depletion, and amortization 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 use our 2010 reserve report to calculate our depletion rate during the first three quarters of 2011. We will use our 2011 reserve report to record our depletion in the fourth quarter of 2011. We expect our 2011 depletion rate to be approximately $1.50 per Mcfe.

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 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 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 change 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.

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

Oil and natural gas sales. Oil and natural gas sales decreased $18.7 million, or 13.2%, to $123.2 million for the year ended December 31, 2009 as compared to $141.9 million for the same period in 2008. Of this decrease, $2.6 million was attributable to decreased production volumes and $74.8 million was attributable to lower market prices for oil and natural gas, offset by a $58.7 million increase attributable to our hedge program. Production for the year ended December 31, 2009 was 17.1 Bcfe, which was 0.3 Bcfe lower than the same period in 2008. Our production was essentially level in the Cherokee Basin due to the success of our 2009 drilling and recompletion program offsetting the natural decline rate associated with our existing wells in the basin. We did not drill any new wells in the Black Warrior Basin during 2009 and the lack of maintenance capital spending in the Black Warrior Basin resulted in a decline of 0.2 Bcfe in production in the basin. This decline would have been higher had we not conducted a workover program in the Black Warrior Basin in early 2009. Our production in the Woodford Shale also declined 0.2 Bcfe during 2009. This is 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 81% of our actual production during 2009 and approximately 89% of our actual production during 2008.

As discussed below, the gain from our unrealized non-cash mark-to-market activities decreased $2.0 million for the year ended December 31, 2009, as compared to the same period in 2008. Our realized prices before our hedging program decreased significantly from $8.13 per Mcfe in 2008 to $3.75 per Mcfe in 2009 primarily due to lower market demand for oil and natural gas as a result of the economic recession. This decline was partially offset by our hedging program and the mark-to-market gains discussed below.

Hedging and mark-to-market activities. As of December 31, 2009, all of our hedges were accounted for as mark-to-market activities. For the year ended December 31, 2009, the unrealized non-cash mark-to-market gain was approximately $19.4 million as compared to an unrealized non-cash $21.4 million mark-to-market gain for the same period in 2008. This 2009 non-cash gain represents approximately $22.2 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 less than $0.1 million loss for non-performance risk related to our counterparties, offset by approximately $2.8 million in losses associated with 2011 and 2012 natural production where we do not expect future volumes to exceed the hedged volumes that had been accounted for previously as cash flow hedges.

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 will not experience any hedge ineffectiveness for 2010, as all our hedges are now accounted for as mark-to-market activities. For the year ended December 31, 2008, we recognized a gain of approximately $1.2 million related to hedge ineffectiveness.

Cash hedge settlements received and hedge premium amortizations paid for our commodity derivatives were approximately $59.5 million for the year ended December 31, 2009. Cash hedge settlements paid for our commodity derivatives were $0.7 million for the year ended December 31, 2008. This difference is primarily due to significantly lower market prices for natural gas during 2009. In 2008, we liquidated our swaption position for cash proceeds of approximately $2.1 million. The original premium paid for the swaption was approximately $1.9 million in 2007.

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, 2009, lease operating expenses decreased $2.7 million, or 7.5%, to $33.5 million, compared to expenses of $36.2 million for the same period in 2008. Of the $2.7 million decrease in lease operating expenses, $2.1 million is related to our Cherokee Basin properties, $0.3 million is related to our Woodford Shale well bores and $0.3 million is related to our Black Warrior properties. By category, our lease operating expenses were lower in 2009 as compared to 2008, because of a $1.5 million decrease in well servicing costs, $0.8 million decrease in field reorganization expenses in Tulsa, $0.3 million decrease in contract labor, and $0.2 million decrease in incremental expenses associated with the Dewey office fire that occurred in 2008, offset by a $0.1 million increase in facilities expenses.

For the year ended December 31, 2009, per unit lease operating expenses were $1.97 per Mcfe compared to $2.09 per Mcfe for the same period in 2008. We have worked to lower our per unit operating costs during 2009. Our decrease in per unit costs is attributable to a decrease in total spending of approximately 7.5% in 2009 as compared the same period in 2008, 0.3 Bcfe in lower production in 2009 as compared to the same period in 2008, and fewer weather-related and specific field office events that occurred in the Cherokee Basin in 2008.

For the year ended December 31, 2009, production taxes decreased $5.2 million, or 62.5%, to $3.2 million, compared to expenses of $8.4 million for the same period in 2008. This decrease was primarily the result of significantly lower market prices for oil and natural gas in 2009 and the impact of production tax credits of approximately $0.3 million.

Cost of sales. For the year ended December 31, 2009, cost of sales decreased by $4.7 million, or 63.7%, to $2.6 million, compared to $7.3 million for the same period in 2008. This represents the cost of purchased natural gas in the Cherokee Basin and was impacted by lower 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, costs billed by CEPM under our management services agreement which was terminated on December 15, 2009, and other costs not directly associated with field operations.

General and administrative expenses increased $4.5 million, or 32.2%, to $18.5 million for the year ended December 31, 2009, as compared to $14.0 million for the same period in 2008. This increase was primarily due to costs associated with transitioning services under the management services agreement from CEPM to CEP. Our general and administrative expenses were higher in 2009 as compared to 2008 because of $5.9 million in higher labor, bonus, and benefits, $1.0 million in non-cash unit-based compensation, $0.2 million in insurance, $0.1 million in rent expense, offset by $1.5 million in lower charges from CEPM, $0.7 million in lower legal fees, and $0.5 million in lower audit and tax fees. For the year ended December 31, 2009 and 2008, CEPM allocated $1.4 million and $2.9 million, respectively, in expenses to us for labor and other charges through the management services agreement.

Our per unit costs were $1.08 per Mcfe for the year ended December 31, 2009 compared to $0.81 per Mcfe for the same period in 2008. This increase is attributable to an increase in total spending of $4.5 million and a 0.3 Bcfe decline in total production volumes. During 2009, total spending increased as services were transitioned from being provided by CEPM under the management services agreement to CEP.

Exploration Costs. Exploration costs increased $0.5 million, or 106.5%, to $0.9 million for the year ended December 31, 2009, as compared to $0.4 million for the same period in 2008. 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 increase in 2009 is primarily as the result of lease abandonments in Kansas.

Gain/loss on sale of asset. Our gain/loss on the sale of assets decreased $0.3 million, or 100.0%, to nothing for the year ended December 31, 2009, as compared to a gain of $0.3 million for the same period in 2008. During 2009, the proceeds from the assets that we sold equaled their book value. In 2008, a fire damaged our field office located in Dewey, Oklahoma. A gain of $0.2 million was recorded for the involuntary conversion as the insurance proceeds of $0.4 million exceeded the $0.2 million book value of the building.

Depreciation, depletion and amortization expense and asset impairments. Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs. 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, 2009 was $71.2 million, or $4.17 per Mcfe, compared to $52.3 million, or $3.01 per Mcfe, for the same period in 2008. The increase in 2009 depreciation, depletion, and amortization 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 0.3 Bcfe decrease in production volumes during 2009 as compared to 2008. 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, 2009 were $5.1 million, compared to $25.6 million for the same period in 2008. Our 2009 non-cash impairment charges were approximately $0.3 million to impair obsolete inventory and other miscellaneous straight-line assets and $4.8 million to impair certain of our well bores in the Woodford Shale. Our 2008 impairment charges were related to $25.6 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.

Interest expense. Interest expense for the year ended December 31, 2009 increased $4.1 million, or 33.6%, to $16.3 million as compared to approximately $12.2 million in interest expense for the same period in 2008. This increase was primarily due to $4.3 million in non-cash mark-to-market losses on our interest rate swaps that are accounted for as market-to-market activities due to lower market interest rates and higher interest rate swap settlements of $3.3 million due to lower market interest rates. This increase was offset by lower cash interest expense due to lower market interest rates of $4.0 million, the accelerated amortization of $0.1 million in debt issue costs as a result of a lender leaving our reserve-based credit facilities, and lower capitalized interest of $0.5 million during 2009 as compared to the same period in 2008. During 2009, we used our excess operating cash flow to reduce our total debt from a high of $220.0 million to $195.0 million. At December 31, 2009, we had an outstanding balance under our reserve-based credit facility of $195.0 million as compared to $212.5 million at December 31, 2008. The average interest rate on our outstanding debt was approximately 6.4% in 2009 compared to 5.45% in 2008. Our capitalized interest decreased from 2008 to 2009 due to lower capital spending in 2009.

Interest income. Interest income for the year ended December 31, 2009 decreased $0.4 million to nothing as compared to approximately $0.4 million in interest income for same period in 2008. During 2008, we earned interest income by utilizing overnight investments on our excess 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, 2009, the balance was an unrealized gain of $28.4 million compared to an unrealized gain of $50.1 million at December 31, 2008. This decrease reflects the settlements during 2009 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 in accumulated other comprehensive income will be amortized to earnings as the positions settle in the future.

The change in Accumulated other comprehensive income (loss) is shown in our consolidated statements of operations and comprehensive income (loss) as an unrealized loss of $21.8 million for the year ended December 31, 2009, and as an unrealized gain of $45.9 million for the same period in 2008. This change is primarily due to the impact of the amortization of locked accumulated other comprehensive income as we realize an offsetting gain upon the physical sale of natural gas production for which 2009 hedges have fixed the future sales price, $2.8 million associated with 2011 and 2012 natural production where we do not expect future volumes to exceed the hedged volumes that had been accounted for previously as cash flow hedges, and $2.9 million associated with interest rate swaps where the underlying debt on our reserve-based credit facilities was repaid.

Liquidity and Capital Resources

During 2010, we utilized our cash flow from operations as our primary source of capital. Our primary use of capital in 2010 was for the retirement of outstanding debt, the development of existing oil and natural gas properties in the Cherokee Basin and for the acquisition of non-operated oil properties in Kansas and Nebraska.

Based upon our current business plan for 2011, we anticipate that we will continue to generate operating cash flows in excess of our working capital needs and planned capital expenditures. The primary focus of our business plan in 2011 will be to use our excess operating cash flows to further reduce our outstanding debt level. As we pursue our business plan, we will be monitoring the capital resources available to us to meet our future financial obligations and planned limited maintenance capital expenditures. Our current expectation is that we will manage our business to operate within the cash flows that are generated. We expect to make limited maintenance capital expenditures of approximately $10.0 million to $12.0 million in the Black Warrior Basin and Cherokee Basin during 2011. This level of maintenance capital expenditures is lower than the $23.0 million in maintenance capital expenditures required to maintain our production levels in 2011. Because we expect to reduce our maintenance capital expenditures in 2011, and had also reduced them in 2010, we expect lower production levels and lower operating cash flows in 2011. 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 2011, we anticipate that our cash flow from operations will decrease from 2010 levels. However, we expect that we will meet our planned capital expenditures and other cash requirements for the twelve months ending December 31, 2011, without increasing our debt or issuing additional equity securities. In 2011, we expect that our excess operating cash flows will be used to reduce our outstanding debt level, which may provide us with additional liquidity from the available borrowing base under our reserve-based credit facility. However, future cash flows and our borrowing capacity are subject to a number of variables, including the level of oil and natural gas production and market prices for those products. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or operating expenses.

Our results will not be fully impacted by significant increases or decreases in natural gas prices because of our hedging program. 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. For 2011, we forecast total net production of between 13.4 Bcfe and 14.2 Bcfe. We have hedged approximately 72% of the midpoint of this forecast, including hedges on 7.6 Bcfe of our Mid-continent production at an average price, including basis, of $7.87 per Mcfe and an additional 2.4 Bcfe of production at a NYMEX-only price of $8.51 per Mcfe. This attractive hedge position locks in a significant portion of our expected operating cash flows for 2011 although we are still exposed to increases or decreases in oil and natural gas prices on our unhedged volumes. Our hedge program is further discussed on page 70.

During 2011, we intend to limit our capital expenditures and to use any surplus operating cash flows to further reduce our debt level. Given our focus on debt reduction, we anticipate that our distribution will remain suspended through the fourth quarter of 2011. We expect that the suspension of our quarterly distribution and the reduction in our total planned capital expenditures in 2011 will provide additional liquidity to fund our operations and to pay down debt. Since we began our debt reduction initiative, we have successfully reduced our outstanding debt balances from a high of $220.0 million to $165.0 million. 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, 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. We are subject to additional future borrowing base redeterminations and cannot forecast the level at which our lenders may set our borrowing base. However, provided that our outstanding debt balance, net of available cash, is less than 90% of our borrowing base as determined by our lenders and at such time we are able to resume maintenance capital expenditures and have available cash, we will evaluate the resumption of our quarterly distribution to unitholders. This evaluation will consider our outstanding borrowings and cash reserves that are set by our board of managers for the proper conduct of our business. Any future quarterly distributions must be approved by our board of managers.

Our reserve-based credit facility currently provides a limited availability to finance future maintenance capital expenditures and other working capital needs. During 2010, we did not borrow any daily short-term or any additional long-term amounts under our reserve-based credit facility. As of February 25, 2011, our borrowing base under our reserve-based credit facility was $195.0 million and we had $165.0 million of debt outstanding under the facility leaving $30.0 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 2012. We expect to lower our outstanding debt levels by $25.0 million to $30.0 million during 2011. 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 indebtness and to fund working capital, capital expenditures and acquisitions. This registration statement will expire in two years. 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 November 13, 2009, we entered into an amended and restated $350.0 million reserve-based credit facility with The Royal Bank of Scotland plc as administrative agent and a syndicate of lenders. The reserve-based credit facility amends, extends, and consolidates our previous reserve-based credit facilities and matures on November 13, 2012. 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%), Wells Fargo Bank, N.A. (14.63%), and Societe Generale (14.63%).

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 February 25, 2011, our borrowing base was $195.0 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, together with, 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 2011. 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 February 25, 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 (defined as, 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 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. 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.

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 February 25, 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 our relationship with Constellation or Constellation’s right to appoint all of the Class A managers of our board of managers.

At December 31, 2010, we believe that we were in compliance with the debt covenants contained in our reserve-based credit facility. We monitor compliance on an ongoing basis. As of December 31, 2010, our actual Total Net Debt to annual Adjusted EBITDA ratio was 2.9 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 3.2 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 9.2 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 the borrowing base below its current level of $195.0 million at one of the future redeterminations by the lenders. During 2011, we intend to use 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 further reduce capital expenditures, continue to suspend our quarterly distributions to unitholders, sell oil and natural gas properties, liquidate in-the-money derivative positions, further 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, 2011, 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 $165.0 million outstanding on our reserve-based credit facility at December 31, 2010. These positions are outlined on page 80.

Cash Flow from Operations

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 net cash flow provided by operating activities for the year ended December 31, 2009 was $56.1 million, compared to net cash flow provided by operating activities of $75.6 million for the same period in 2008. This decrease in operating cash flow was primarily attributable to lower oil and natural gas as the result of significantly lower market prices for natural gas on our unhedged production volumes. For 2009, our operating cash flows were reduced by $74.8 million due to lower oil and natural gas prices and $2.6 million due to lower production volumes, offset by $59.8 million related to our cash hedge settlements received for our natural gas commodity derivatives and $4.8 paid for our interest rate derivatives. Our change in working capital from 2008 to 2009 was impacted by lower accounts receivable of $1.0 million and an increase in accrued liabilities of $2.2 million partially offset by lower accounts payable of $1.7 million, higher prepaid expenses and lower affiliate payables of $0.9 million. Our receivables balance decreased due to increased collections and lower current period prices for our current estimated natural gas sales prices in the Cherokee Basin. Our accounts payable decreased due to lower lease operating expenses and timing of invoice payments. The decrease in affiliate payables of $0.9 million primarily resulted from the timing of the payment for expenses incurred under the management services agreement. Our accrued liabilities increased as a result of compensation expenses related to transitioning employees and services from CEPM to us.

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, refer to *Outlook* on page 73.

We enter into hedging arrangements to reduce the impact of natural gas price volatility on our operations. By removing the price volatility from a significant portion of our natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. We currently have no oil hedges, but may have some in the future. 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 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 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, 2014. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps—NYMEX

	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
2011	2,400,000	$ 8.55	2,425,000	$ 8.55	2,220,000	$ 8.45	2,220,000	$ 8.45	9,265,000	$ 8.51
2012	2,227,500	$ 8.34	2,227,500	$ 8.34	2,250,000	$ 8.34	2,250,000	$ 8.34	8,955,000	$ 8.34
2013	2,025,000	$ 7.33	2,079,500	$ 7.32	2,070,000	$ 7.33	2,038,000	$ 7.34	8,212,500	$ 7.33
2014	1,575,000	$ 7.03	1,592,500	$ 7.03	1,610,000	$ 7.03	1,610,000	$ 7.03	6,387,500	$ 7.03
									32,820,000	

MTM Fixed Price Swaps—CenterPoint Energy Gas Transmission (East)

	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
2011	180,000	$ 7.93	180,000	$ 7.93	180,000	$ 7.93	180,000	$ 7.93	720,000	$ 7.93
									720,000	

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 $
2011	1,947,352	$ 0.63	1,823,324	$ 0.65	1,703,467	$ 0.62	1,393,700	$ 0.68	6,867,843	$ 0.64
2012	1,502,800	$ 0.58	1,427,100	$ 0.59	1,352,900	$ 0.61	1,295,900	$ 0.62	5,578,700	$ 0.60
2013	1,245,400	$ 0.40	1,192,900	$ 0.40	1,145,700	$ 0.40	1,104,400	$ 0.40	4,688,400	$ 0.40
2014	1,053,465	$ 0.40	1,010,529	$ 0.40	971,508	$ 0.40	939,067	$ 0.40	3,974,569	$ 0.40
									21,109,512	

Investing Activities—Acquisitions and Capital Expenditures

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 currently have 3 net wells and 2 net sidetracks in progress. We anticipate that each of these in progress wells will be completed upon the installation of gathering lines during 2011. We used $1.3 million of our materials and supplies inventory in our 2010 drilling and workover programs. During 2011, we expect to use an additional $0.3 million in inventory on our drilling operations in the Black Warrior Basin. We do not plan to restock the inventory items that we use. 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.

Cash used in investing activities was $22.6 million for the year ended December 31, 2009, compared to $95.0 million for the same period in 2008. Our cash capital expenditures were $22.9 million in 2009, which primarily related to drilling and development of oil and natural gas properties in the Cherokee Basin. In 2009, we drilled and completed 60 net wells and 17 net recompletions in the Cherokee Basin. We also prepared 10 drilling locations in the Black Warrior Basin. We also settled post-closing adjustments on our CoLa and Newfield acquisitions of $0.2 million. 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.

Our capital spending to develop our oil and natural gas properties of $7.9 million in 2010 was reduced from our 2009 spending level of $22.9 million and our 2008 spending level of $47.9 million. We currently anticipate our total capital budget for 2011 will be between $10.0 million and $12.0 million. This 2011 capital budget primarily consists of capital for drilling wells and recompletions and also includes amounts for infrastructure projects, equipment, and inventory. The 2011 budget is set below our 2011 estimated maintenance capital level of $23.0 million and our 2010 estimated maintenance capital level of $25.3 million. We expect that our current and future capital expenditures will continue to be funded using our cash flow from operations. We believe this decreased level of maintenance capital spending will result in lower production volumes in future periods. Because we have reduced our capital spending below a maintenance level, we anticipate lower production in 2011. In addition, we also expect our production in the first quarter of 2011 to be lowered by severe winter weather that impacted our operations. We expect these factors to reduce our operating cash flows in 2011. Once market conditions warrant, we expect to evaluate the resumption of capital spending at a level sufficient to maintain our then current production rate. We believe that natural gas prices in excess of $6.00 per Mcfe produce rates of return that generally support capital spending at maintenance levels. The amount and timing of our capital expenditures is largely discretionary and within our control. If natural gas prices decline further, and the total borrowing base under our reserve-based credit facility is further reduced, or drilling costs escalate, we could choose to defer a portion of any planned capital expenditures until later periods.

Financing Activities

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. Through February 25, 2011 we reduced our outstanding debt levels from a high of $220.0 million to $165.0 million or by 25%. 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. During 2010, we did not borrow any daily short-term or any additional long-term amounts under our reserve-based credit facility.

We have suspended our $0.13 per unit quarterly distributions to unitholders since the quarter ended June 30, 2009, to reduce our outstanding indebtedness. Given our current focus on debt reduction, we anticipate that our distribution will remain suspended through the fourth quarter of 2011. Assuming that the quarterly distribution rate would have remained at $0.13 per unit for each quarter in 2011, this suspension of the quarterly distribution would provide approximately $12.6 million in cash flow during 2011 that could be used to reduce our outstanding debt balance under our reserve-based credit facility. We have also suspended $3.6 million in quarterly distributions on the Class D interests associated with each of the quarterly periods since March 31, 2008. We expect that these quarterly distributions on the Class D interests, and all future quarterly distributions on the Class D interests, will remain suspended until such time as distributions are permitted under our reserve-based credit facility and limited liability company agreement. For additional information, refer to *Outlook* on page 73.

Our net cash used by financing activities was $28.4 million for the year ended December 31, 2009, compared to $6.9 million provided by financing activities for the same period in 2008. During 2009, we used $17.5 million in operating cash flows to reduce our outstanding debt level. During 2009, we reduced our outstanding debt levels from $220.0 million to $195.0 million or by 11.4%. We also entered into a new reserve-based credit facility that matures in November 2012 and incurred approximately $5.0 million in debt issue costs.

We paid distributions of $5.8 million to our common and Class A unitholders in 2009. We also suspended $2.3 million in quarterly distributions on the Class D interests associated with each of the quarterly periods since March 31, 2008. In 2008, we borrowed a net of $59.5 million to fund the CoLa acquisition, to fund debt issue costs, to finance capital expenditures, and for working capital needs. We also paid distributions of $50.7 million to our common and Class A unitholders and on the Class D interests in 2008 and incurred $0.3 million in costs associated with our shelf registration statement. For the year ended December 31, 2008, our distributions to unitholders exceeded our distributable cash flow such that our distribution coverage ratio was less than 1.0. This coverage ratio compares our distribution rate to our distributable cash flow. Our distributable cash flow reflects Adjusted EBITDA reduced by estimated maintenance capital expenditures and cash interest expense. Our maintenance capital is the amount of capital spending required to maintain our production rates, reserves, and asset base. We reduced our quarterly distribution rate for the quarter ended December 31, 2008, to $0.13 per unit in order to improve our expected coverage ratio and to provide additional liquidity. Our distribution has been suspended since the quarter ended June 30, 2009.

Contractual Obligations

At December 31, 2010, we had the following contractual obligations or commercial commitments:

	Payments Due By Year(1)(2) (in thousands)					
	2011	2012	2013	2014	Thereafter	Total
Reserve-Based Credit Facility	—	165,000	—	—	—	165,000
Support Services Agreement	1,230	—	—	—	—	1,230
Offices Leases	416	424	408	422	752	2,422
Total	$1,646	$165,424	$408	$422	$ 752	$ 168,652

(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 4.8% at December 31, 2010.

At December 31, 2010, our asset retirement obligation was approximately $13.0 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 25, 2011, we have not suffered any losses with our counterparties as a result of nonperformance in the current economic and credit crisis.

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 $8.0 million in purchases through December 31, 2011. As of February 25, 2011, we have no past due receivables from Macquarie.

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 25, 2011, 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 23, 2011. As of February 25, 2011, 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 25, 2011, we have no past due receivables from J.P. Morgan Ventures Energy Corporation.

Derivative Counterparties

As of February 25, 2011, all of our derivatives are with BNP Paribas, The Royal Bank of Scotland plc, Societe Generale, The Bank of Nova Scotia, and Wells Fargo Bank, N.A. These banks are lenders who participate in our reserve-based credit facility. All of our derivatives are collateralized by the assets securing our reserve-based credit facility and therefore currently do not require the posting of cash collateral. As of February 25, 2011, each of these financial institutions has an investment grade credit rating.

Reserve-Based Credit Facility

As of February 25, 2011, 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%), Wells Fargo Bank, N.A. (14.63%), and Societe Generale (14.63%). As of February 25, 2011, each of these financial institutions has an investment grade credit rating.

Outlook

During 2011, we expect that our business will continue to be affected by the factors described in Part II, 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 2011 Expected Results

Our 2011 business plan and forecast is focused on further reducing our outstanding debt level and promoting financial flexibility by limiting capital expenditures and an anticipated continued suspension of our quarterly distribution through the fourth quarter of 2011. 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.

We currently anticipate that for 2011:

- Our production to be between 13.4 Bcfe and 14.2 Bcfe, approximately 72% of which is currently hedged at a level above current market prices.
- Our operating expenses to be actively managed, resulting in a range of $48.0 million to $52.0 million.
- Our total capital expenditures to be between $10.0 million and $12.0 million, which assumes a decline rate of 15 percent and a dollar per flowing Mcfe range of $3,200 to $3,800. This capital budget has been held steady with our 2010 budgeted capital expenditures, which was reduced to a level below our estimated maintenance level of capital expenditures of $25.3 million for 2010 and $23 million for 2011. We expect to drill and complete approximately 30 to 35 net wells, sidetracks, and recompletions, both in the Black Warrior Basin and in the Cherokee Basin. We have very limited amounts of lease expirations during 2011 and 2012, which generally allows us to reduce our drilling activities without losing our undeveloped locations. 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.
- We anticipate that our operating cash flows may allow for a $25.0 million to $30.0 million reduction of our outstanding debt level at December 31, 2011, below our $165.0 million balance at December 31, 2010.
- We anticipate that our quarterly distributions to our unitholders will remain suspended through the fourth quarter of 2011. All future quarterly distributions must be approved by our board of managers.

Impact of 2011 Plan

Our 2011 operating plan is intended to further reduce our outstanding debt by continuing our reduction of capital expenditures and continuing the suspension of our quarterly distribution to unitholders. We expect that these plans will result in lower production levels in 2011. This limited level of maintenance capital spending would likely result in lower production levels continuing into future periods. We do not believe, however, that during this potential extended period of limited maintenance capital expenditures, we would lose any significant leased acreage. These plans are expected to reduce our leverage, continue to improve our liquidity position, and reduce future cash interest expenses on our outstanding unhedged debt. When we forecast over the next five years, we currently expect that our existing asset base and hedge portfolio will allow us to substantially reduce our debt while funding a limited capital program.

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 that are believed to be reasonable under the circumstances, the results of which 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 an expanded discussion of our more critical accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in the preparation of the consolidated financial statements. Please read Note 1 to the 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. 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.

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.

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. Cash flow estimates for the impairment testing are based on third party reserve reports and exclude derivative instruments. Refer to Note 5 to the 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 in Alabama, Kansas, and Oklahoma. 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 impaired is deemed to have occurred.

Property acquisition costs are capitalized when incurred.

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 reserve engineer. 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. Our 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.

Net Profits Interest

A significant portion of our wells in the Robinson's Bend Field in the Black Warrior Basin are subject to the NPI. The NPI represents an interest in production created from the working interest and is based on a contractual revenue calculation. We account for the NPI as an overriding royalty interest. This is consistent with our accounting for the NPI for reserve estimate purposes. Similar to royalty payments, our revenue excludes any payments made to the NPI holder.

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 gas imbalance positions at December 31, 2010, 2009, and 2008.

Hedging Activities

We have implemented a hedging policy to hedge a portion of our expected natural gas production for a period of up to five years, as we deem appropriate. We account for all our open commodity derivatives as mark-to-market activities.

We use interest rate swaps to mitigate the impact of volatility of changes in the LIBOR interest rate on our interest payments for our debt. We account for these hedging activities as mark-to-market activities.

All of our derivatives are not accounted for as cash flow hedges but are effective as economic hedges of our commodity price 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 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.

If we ever accounted 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 will reclassify the amounts recorded in other comprehensive income into earnings. We 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 income statement, we record settled natural gas derivatives as “Oil and gas sales” and settled interest rate swaps as “Interest expense (income).”

Accounting Standards Adopted Through February 25, 2011

In January 2010, the FASB issued its final guidance on additional supplemental fair value disclosures. Two new disclosures are required: (1) a “gross” presentation of activities (purchases, sales, and settlements) within the Level 3 roll forward reconciliation, which will replace the “net” presentation format, and (2) detailed disclosures about the transfers between Level 1 and 2 measurements. The guidance also provides several clarifications regarding the level of disaggregation and disclosures about inputs and valuation techniques. The new disclosures became effective for the first quarter 2010 for calendar year-end companies, except for the Level 3 “gross” activity disclosures, which will be deferred until the first quarter of 2011. The adoption of this guidance did not have a material impact on our financial statements or our disclosures.

In February 2010, the FASB amended its guidance on subsequent events. SEC filers are now not required to disclose the date through which an entity has evaluated subsequent events. The amended guidance was effective upon issuance. The adoption of this guidance did not have a material impact on our financial statements or our disclosures.

In December 2009, the FASB issued its final oil and gas accounting rules to align the oil and gas reserve estimation and disclosure requirements of Accounting Standards Update (ASU) 2010-03, Extractive Industries—Oil and Gas (Topic 932) with the requirements in the SEC’s final rule, *Modernization of the Oil and Gas Reporting Requirements,* which was issued on December 31, 2008 and is effective for the year ended December 31, 2009. The adoption of these oil and gas reserve estimation and disclosure requirements impacted the estimated reserve quantities in our 2009 independent third-party reserve report. One of the primary impacts was the use of an average 12-month price instead of a year-end price. The average 12-month price was significantly lower than the year-end price that was used under the old rules. Under the old rules, our NYMEX price would have been $5.79 and the price in the Cherokee Basin would have been $5.73 instead of a NYMEX price of $3.92 and a price in the Cherokee Basin of $3.11. Had these old SEC prices been used, our total proved reserves would have been 218.9 Bcfe instead of 131.2 Bcfe, our total proved undeveloped reserves would have been 55.1 Bcfe instead of 19.1 Bcfe, and our standardized measure would have been $283.2 million instead of $97.2 million. The other impact was that we historically recorded proved undeveloped locations for greater than 5 years and now we record proved undeveloped locations only for the next 5 years. These locations beyond a 5 year drilling schedule are now classified as probable reserves. Because of this change, we reclassified approximately 23.9 Bcfe of reserves in the Black Warrior Basin as probable reserves. We also used to record only one offset location to each our proved undeveloped locations but now we are able record any offsets on one section surrounding existing production subject to available infrastructure. This had a limited impact in 2009 because of the low SEC-required price for natural gas which made all of our proved undeveloped locations on our Osage concession uneconomic at the low price. Additionally, 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. We continued this practice in 2009. The impact of the adoption of the FASB and SEC final rule on our financial statements is not practicable to estimate due to the operational and technical challenges associated with calculating a cumulative effect of adoption by preparing reserve reports under both the old and new rules. However, had we calculated our 2009 reserves using year-end pricing instead of the average 12-month price, the impact would have been a decrease of at least $14.5 million in depletion in our fourth quarter 2009 financial statements.

In June 2009, the FASB released the final version of its new Accounting Standards Codification (the "Codification") as the single authoritative source for U.S. GAAP. The Codification replaces all previous U.S. GAAP accounting standards as described in ASC 105 (SFAS 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles)*. While not intended to change U.S. GAAP, the Codification significantly changes the way in which the accounting literature is organized. It is structured by accounting topic to help accountants and auditors more quickly identify the guidance that applies to a specific accounting issue. However, because the Codification completely replaces existing standards, it will affect the way U.S. GAAP is referenced by companies in their financial statements and accounting policies. The Codification is effective for financial statements that cover interim and annual periods ending after September 15, 2009. The adoption of the Codification did not have an impact on our financial statements.

In May 2009, the FASB established general standards of accounting for and the disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that currently exist in the auditing standards. The standard, which includes a new required disclosure of the date through which an entity has evaluated subsequent events, is effective for interim or annual periods ending after June 15, 2009. We perform an evaluation of subsequent events until the issuance date of our document with the SEC so the adoption of the new requirements had no impact on our financial statements.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2010, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. We are currently reviewing the recently issued standards and interpretations but none are expected to have a material impact on our financial statements.

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 has improved during 2010 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 have declined since December 31, 2009. This decline in future expected prices for natural gas led to an impairment of our oil and natural gas assets during 2010.

We expect that our ability to issue debt and equity securities may 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 remain depressed or decline further, which may cause us to impair our oil and natural gas properties in 2011, thereby reducing our borrowing base. In response to the credit crisis and the decline in the market prices for natural gas, we have suspended our cash distribution since June 2009 and lowered our maintenance capital spending in 2009 and 2010, and will do so again in 2011. If market prices for natural gas remain depressed, 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 reinstatement of our distributions to unitholders.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas production. Realized pricing is primarily driven by the 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 Pipeline (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, and the spot market prices applicable to all of our natural gas production. Historically, pricing for natural gas production 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 debt reduction. The prices we receive for 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 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 natural gas 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 risks 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					
December 31, 2010	$ 86,931	$ 71,578	$ (15,353)	$ 102,284	$ 15,353

Interest Rate Risk

At December 31, 2010, the one-month LIBOR rate was 0.261%, the three-month LIBOR rate was 0.303%, and our applicable margin on LIBOR borrowings was 3.25%. At December 31, 2010, the ABR rate was 3.25%, and our applicable margin on ABR borrowings was 2.25%. At December 31, 2010, we had debt outstanding of $165.0 million. All of this amount incurred interest at three-month LIBOR rates plus an applicable margin of 3.25% based on utilization. We had no debt outstanding at the one-month LIBOR or ABR rates. At December 31, 2010, the carrying value and fair value of our debt is $165.0 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 (in 000's)	Fair Value	(Decrease)
Impact of changes in LIBOR on derivative interest rate instruments December 31, 2010	$ (3,573)	$ (2,799)	$ 774	$ (4,347)	$ (774)

We enter into hedging arrangements to reduce the impact of volatility of changes in the LIBOR interest rate on our interest payments for our debt. At December 31, 2010, we have the following outstanding interest rate swaps that fix our LIBOR rate on $93.0 million of our $165.0 million in outstanding debt:

Maturity Date	Total Debt Hedged (in 000's)	LIBOR Fixed Rate
August 20, 2014	$ 11,000	2.37%
September 20, 2014	$ 45,000	2.52%
October 19, 2014	$ 29,500	2.68%
October 22, 2014	$ 7,500	2.61%

Item 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required to be filed under this item are presented on pages 88 through 129 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, 2010 (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.

Changes in Internal Control over Financial Reporting

During the three months ended December 31, 2010, 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, 2010. 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.

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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, internal auditors, and PricewaterhouseCoopers LLP to review the activities of each in discharging their responsibilities. The internal audit staff and PricewaterhouseCoopers LLP have free access to the audit committee.

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, 2010.

Item 9B. Other Information

None.

PART III

Item 10. Managers, Executive Officers and Corporate Governance

The information required by this item will be set forth in our Proxy Statement for the 2011 Annual Meeting and is incorporated herein by reference.

Item 11. Executive Compensation

The information required by this item will be set forth in our Proxy Statement for the 2011 Annual Meeting and is incorporated herein by reference.

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

The additional information required by this item will be set forth in our Proxy Statement for the 2011 Annual Meeting and is incorporated herein by reference.

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

The information required by this item will be set forth in our Proxy Statement for the 2011 Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accountant 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, 2010 and 2009.

Audit Fees. The aggregate fees billed for the financial statement audit or services provided in connection with statutory or regulatory filings for the years ending 2010 and 2009 were $897,344 and $932,484, respectively.

Audit-Related Fees. The aggregate audit-related fees billed by PricewaterhouseCoopers LLP for the years ending 2010 and 2009 were $11,970 and $3,600, 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 ending 2010 and 2009 were $684,728 and $466,147, respectively.

All Other Fees. The other fees billed by our principal accountant for the years ending 2010 and 2009 for services other than those described above were $7,500 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.

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 25, 2011 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Income (Loss)—Constellation Energy Partners LLC for the three years ended December 31, 2010

Consolidated Balance Sheets—Constellation Energy Partners LLC at December 31, 2010 and December 31, 2009

Consolidated Statements of Cash Flows—Constellation Energy Partners LLC for the three years ended December 31, 2010

Consolidated Statements of Changes in Members' Equity—Constellation Energy Partners LLC for the three years ended December 31, 2010

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).

Exhibit Number	Description
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 ("Amendment No. 2").
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, between 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).
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 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 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 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 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	—Management Services Agreement, dated as of November 20, 2006, by and among Constellation Energy Partners LLC and Constellation Energy Partners Management, LLC (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
10.2	—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).

Exhibit Number	Description
10.3	—Net Overriding Royalty Conveyance, dated as of November 22, 1993, but effective as of October 1, 1993, pursuant to Part I thereof, from Velasco Gas Company, Ltd. to Torch Energy Advisors Incorporated herein, and pursuant to Part II thereof, from Torch Energy Advisors Incorporated herein to the Torch Energy Royalty Trust (incorporated herein by reference to Exhibit 10.4 to Amendment No. 2).
10.4	—Oil and Gas Purchase Agreement, dated as of October 1, 1993, by and between Torch Energy Marketing, Inc., Torch Royalty Company and Velasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2).
10.5	—Letter agreement, dated as of June 13, 2005, by and between Robinson’s Bend Marketing II, LLC and Torch Energy TM, Inc. (incorporated herein by reference to Exhibit 10.6 to Amendment No. 2).
10.6	—$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, and 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).
10.7	—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).
10.8	—Trademark License Agreement, dated as of November 20, 2006, by and between 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).
10.9	—Water Gathering and Disposal Agreement, dated August 9, 1990, by and between Torch Energy Associates Ltd. and Velasco 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 October 1, 1993, by and between Torch Energy Associates Ltd. and Velasco 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 November 30, 2004, by and between Robinson’s Bend Operating Company, LLC, successor in interest to Torch Energy Associates Ltd., and Everlast Energy LLC, successor in interest to Velasco Gas Company Ltd. (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	—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).
10.13	—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).

Exhibit Number	Description
10.14	—Assignment, Assumption and Ratification Agreement, dated 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).
+10.15	—Letter Agreement, dated December 31, 2008, between Constellation Energy Partners LLC and Stephen R. Brunner (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on January 7, 2009, File No. 001-33147).
+10.16	—Letter Agreement, dated December 31, 2008, between Constellation Energy Partners LLC and Charles C. Ward (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on January 7, 2009, File No. 001-33147).
+10.17	—Letter Agreement, dated December 31, 2008, between Constellation Energy Partners LLC and Lisa J. Mellencamp (incorporated herein by reference to Exhibit 10.22 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
+10.18	—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).
+10.19	—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).
+10.20	—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).
+10.21	—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).
+10.22	—Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Stephen R. Brunner (incorporated herein by reference to Exhibit 10.5 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
+10.23	—Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Charles C. Ward (incorporated herein by reference to Exhibit 10.6 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
+10.24	—Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Lisa J. Mellencamp (incorporated herein by reference to Exhibit 10.7 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
+10.25	—Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Michael B. Hiney (incorporated herein by reference to Exhibit 10.8 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
+10.26	—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).
+10.27	—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).

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Exhibit Number	Description
+10.28	—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).
+10.29	—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).
+10.30	—Form of Grant Agreement Relating to Restricted Units—Independent Managers (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 March 3, 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.

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

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REPORTS 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it estimates the quantities of proved oil and natural gas reserves in 2009. As discussed in Notes 7 and 17 to the consolidated financial statements, the Company has entered into significant transactions with Constellation Energy Group, Inc. and its affiliates, a related party.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 25, 2011

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Income (Loss)

	For the year ended December 31, 2010	For the year ended December 31, 2009	For the year ended December 31, 2008
		(In 000's except unit data)	
Revenues			
Oil and gas sales	$ 108,692	$ 123,126	$ 141,863
Gain / (Loss) from mark-to-market activities (see Note 3)	42,081	19,410	21,376
Total revenues	150,773	142,536	163,239
Expenses:			
Operating expenses:			
Lease operating expenses	30,798	33,535	36,257
Cost of sales	2,473	2,638	7,261
Production taxes	3,179	3,153	8,398
General and administrative expenses	20,351	18,506	13,998
Exploration costs	760	855	414
(Gain) / Loss on sale of assets	(18)	—	(301)
Depreciation, depletion and amortization	85,263	71,173	52,281
Asset impairments (see Note 5)	272,487	5,113	25,638
Accretion expense	822	406	411
Total operating expenses	416,115	135,379	144,357
Other expense / (income)			
Interest expense	12,721	11,967	12,167
Interest expense (Gain)/Loss from mark-to-market activities (see Note 3)	(765)	4,338	—
Interest (income)	(3)	(2)	(350)
Other expense (income)	(385)	(123)	(203)
Total other expenses / (income)	11,568	16,180	11,614
Total expenses	427,683	151,559	155,971
Net income (Loss)	$ (276,910)	$ (9,023)	$ 7,268
Other comprehensive (Loss)	(17,447)	(21,760)	45,903
Comprehensive (Loss)	$ (294,357)	$ (30,783)	$ 53,171
Earnings per unit (see Note 1)			
Earnings (loss) per unit—Basic	$ (11.36)	$ (0.40)	$ 0.32
Units outstanding—Basic	24,370,545	22,664,895	22,370,426
Earnings (loss) per unit—Diluted	$ (11.36)	$ (0.40)	$ 0.32
Units outstanding—Diluted	24,370,545	22,664,895	22,370,426
Distributions declared and paid per unit	$ —	$ 0.26	$ 2.25

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

	December 31, 2010		December 31, 2009
		(In 000's)	
ASSETS			
Current assets			
Cash and cash equivalents	$ 7,892		$ 11,337
Accounts receivable	7,371		8,379
Prepaid expenses	1,315		1,298
Risk management assets (see Note 3)	36,513		24,251
Total current assets	53,091		45,265
Oil and natural gas properties (See Note 5)			
Oil and natural gas properties, equipment and facilities	774,060		794,520
Material and supplies	2,073		4,312
Less accumulated depreciation, depletion, amortization, and impairments	(499,214)		(186,207)
Net oil and natural gas properties	276,919		612,625
Other assets			
Debt issue costs (net of accumulated amortization of $4,888 at December 31, 2010 and $2,924 at December 31, 2009)	3,727		5,590
Risk management assets (see Note 3)	46,986		33,916
Other non-current assets	3,654		10,921
Total assets	$ 384,377		$ 708,317
LIABILITIES AND MEMBERS' EQUITY			
Liabilities			
Current liabilities			
Accounts payable	$ 1,418		$ 1,102
Payable to affiliate	—		201
Accrued liabilities	10,369		10,033
Environmental liabilities	—		193
Royalty payable	2,605		4,747
Risk management liabilities (see Note 3)	141		208
Total current liabilities	14,533		16,484
Other liabilities			
Asset retirement obligation	13,024		12,129
Debt	165,000		195,000
Total other liabilities	178,024		207,129
Total liabilities	192,557		223,613
Commitments and contingencies (See Note 8)			
Class D Interests	6,667		6,667
Members' equity			
Class A units, 487,750 and 476,950 shares authorized, issued and outstanding, respectively	3,485		8,993
Class B units, 24,298,763 and 24,298,763 shares authorized, respectively, and 23,899,758 and 23,376,136 issued and outstanding, respectively	170,748		440,677
Accumulated other comprehensive income	10,920		28,367
Total members' equity	185,153		478,037
Total liabilities and members' equity	$ 384,377		$ 708,317

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, 2010	For the year ended December 31, 2009	For the year ended December 31, 2008
		(In 000's)	
Cash flows from operating activities:			
Net income (loss)	$ (276,910)	$ (9,023)	$ 7,268
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	85,263	71,173	52,281
Asset impairments (see Note 5)	272,487	5,113	25,638
Amortization of debt issuance costs	1,964	1,429	1,052
Accretion expense	822	406	411
Equity (earnings) losses in affiliate	(385)	(125)	(203)
(Gain) Loss from disposition of property and equipment	(18)	—	(301)
Bad debt expense	69	—	—
Dryhole costs	61	173	—
Hedge ineffectiveness	—	267	(1,189)
(Gain) Loss from mark-to-market activities	(42,846)	(15,072)	(21,376)
Unit-based compensation programs	1,849	1,308	322
Changes in Assets and Liabilities:			
Change in net risk management assets and liabilities	(1)	420	2,518
(Increase) decrease in accounts receivable	939	984	9,130
(Increase) decrease in prepaid expenses	(15)	(275)	714
(Increase) decrease in other assets	1	33	241
Increase (decrease) in accounts payable	316	(1,707)	875
Increase (decrease) in payable to affiliate	(201)	(842)	(1,770)
Increase (decrease) in accrued liabilities	(424)	2,203	(2,160)
Increase (decrease) in royalty payable	(2,142)	(378)	2,181
Net cash provided by operating activities	40,829	56,087	75,632
Cash flows from investing activities:			
Cash paid for acquisitions, net of cash acquired	(6,369)	(291)	(48,063)
Development of natural gas properties	(7,973)	(22,913)	(47,897)
Proceeds from sale of equipment	91	130	599
Distributions from equity affiliate	485	503	353
Net cash used in investing activities	(13,766)	(22,571)	(95,008)
Cash flows from financing activities:			
Members' distributions	—	(5,820)	(50,656)
Proceeds from issuance of debt	—	37,500	237,000
Repayment of debt	(30,000)	(55,000)	(177,500)
Costs for shelf registration statement	—	—	(340)
Units tendered by employees for tax withholdings	(376)	(6)	—
Equity issue costs	(2)	(82)	—
Debt issue costs	(130)	(5,026)	(1,562)
Net cash (used in) provided by financing activities	(30,508)	(28,434)	6,942
Net (decrease) increase in cash	(3,445)	5,082	(12,434)
Cash and cash equivalents, beginning of period	11,337	6,255	18,689
Cash and cash equivalents, end of period	$ 7,892	$ 11,337	$ 6,255
Supplemental disclosures of cash flow information:			
Change in accrued capital expenditures	$ 523	$ (2,760)	$ (124)
Cash received during the period for interest	$ 3	$ 2	$ 372
Cash paid during the period for interest	$ (7,106)	$ (6,225)	$ (10,545)
Cash paid during the period for income taxes	$ (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 Units	Class A Amount	Class B Units	Class B Amount	Accumulated Other Comprehensive Income	Total Members' Equity
			(In 000's, except unit data)			
Balance, December 31, 2007	447,022	$10,104	21,904,106	$ 495,074	$ 4,224	$ 509,402
Distributions	—	(1,008)	—	(49,315)	—	(50,323)
Issuance of common units, net of issue costs of $5,465	—	—	—	—	48,966	48,966
Unit-based compensation programs	—	—	—	—	1,929	1,929
Change in fair value of commodity hedges	—	—	—	—	(4,992)	(4,992)
Cash gains on settlement of commodity hedges	699	7	34,236	315	—	322
Contributions	—	17	—	833	—	850
Net income	—	145	—	7,123	—	7,268
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

See accompanying notes to consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2010, 2009 and 2008

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, under the laws of the State of Delaware. We completed our initial public offering on November 20, 2006, and trade on the NYSE Arca under the symbol "CEP". We are partially-owned by Constellation Energy Commodities Group, Inc. ("CCG"), which is owned by Constellation Energy Group, Inc. (NYSE: CEG) ("Constellation" or "CEG"). As of December 31, 2010, affiliates of Constellation own all of our Class A units, all of the management incentive interests, approximately 25% of our common units 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 $1.6 million in 2010 and $0.9 million in 2009 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. During 2010, there was bad debt expense of less than $0.1 million and there was no bad debt expense in 2009 and 2008. We have no off-balance-sheet credit exposure related to our operations or customers.

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. For the year ended December 31, 2008, five customers accounted for approximately 27%, 19%, 15%, 13% and 9% of our sales revenues.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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 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 gas reserves.

Oil and Natural Gas Reserve Quantities

Our estimate of proved reserves was based on the quantities of 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, 2010, 2009 and 2008 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, natural gas, and natural gas liquids eventually recovered.

Derivatives and Hedging Activities

We use derivative financial instruments to achieve a more predictable cash flow from our 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 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." We record settled natural gas swaps as "Gas sales" and settled interest rate swaps as "Interest expense."

Net Profits Interest

Certain of our properties in the Robinson's Bend Field are subject to a net profits interest ("NPI"). The NPI represents an interest in production created from the working interest and is based on a contracted revenue calculation (see Note 10). The NPI is accounted for as an overriding royalty interest. This is consistent with how we account for the NPI for reserves purposes. Any payments made to the NPI holder are reflected as a reduction in revenue.

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, 2010, 2009, or 2008.

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 2010, the current federal and state tax liability for the entity was approximately $0.02 million. This amount was paid to the IRS or the applicable states in quarterly installments. The entity had no deferred tax assets or liabilities.

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 Statement 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,

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

- 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

The following table presents earnings per common unit amounts:

Year ended December 31, 2010	Income (loss)	Unit	Per Unit Amount
	(In 000's except unit data)		
Basic EPS:			
Income allocable to unitholders	$(276,910)	24,370,545	$(11.36)
Effect of dilutive securities:			
Restricted common units that earn distributions	—	—	—
Diluted EPS:			
Income allocable to common unitholders	$(276,910)	24,370,545	$(11.36)

Year ended December 31, 2009	Income (loss)	Unit	Per Unit Amount
	(In 000's except unit data)		
Basic EPS:			
Income allocable to unitholders	$ (9,023)	22,664,895	$ (0.40)
Effect of dilutive securities:			
Restricted common units that earn distributions	—	—	—
Diluted EPS:			
Income allocable to common unitholders	$ (9,023)	22,664,895	$ (0.40)

Year ended December 31, 2008	Income	Unit	Per Unit Amount
	(In 000's except unit data)		
Basic EPS:			
Income allocable to unitholders	$ 7,268	22,370,426	$ 0.32
Effect of dilutive securities:			
Restricted common units that earn distributions	—	—	—
Diluted EPS:			
Income allocable to common unitholders	$ 7,268	22,370,426	$ 0.32

Comprehensive Income (Loss)

Comprehensive income (loss) includes net earnings (loss) as well as unrealized gains and losses on derivative instruments.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Class D Interests

Due to their contingently redeemable feature, the Class D interests are treated as preferred units subject to contingent redemption.

Environmental Cost

We record environmental liabilities at their undiscounted amounts on our balance sheet 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.

Unit-Based Compensation

We record compensation expense for all equity grants issued under the Long-Term Incentive Program, the 2009 Omnibus Incentive Compensation Plan, and the Executive Inducement Bonus Program 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.

Accounting Standards Adopted Through February 25, 2011

In January 2010, the FASB issued its final guidance on additional supplemental fair value disclosures. Two new disclosures are required: (1) a "gross" presentation of activities (purchases, sales, and settlements) within the Level 3 roll forward reconciliation, which will replace the "net" presentation format, and (2) detailed disclosures about the transfers between Level 1 and 2 measurements. The guidance also provides several clarifications regarding the level of disaggregation and disclosures about inputs and valuation techniques. The new disclosures became effective for the first quarter 2010 for calendar year-end companies, except for the Level 3 "gross" activity disclosures, which will be deferred until the first quarter of 2011. The adoption of this guidance did not have a material impact on our financial statements or our disclosures.

In February 2010, the FASB amended its guidance on subsequent events. SEC filers are now not required to disclose the date through which an entity has evaluated subsequent events. The amended guidance was effective upon issuance. The adoption of this guidance did not have an impact on our financial statements or our disclosures.

In September 2009, the FASB issued its proposed updates to oil and gas accounting rules to align the oil and gas reserve estimation and disclosure requirements of Accounting Standards Update (ASU) 2010-03, Extractive Industries—Oil and Gas (Topic 932) with the requirements in the SEC's final rule, *Modernization of the Oil and*

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Gas Reporting Requirements, which was issued on December 31, 2008 and is effective for the year ended December 31, 2009. The final rule adopts revisions to the SEC's oil and gas reporting disclosure requirements. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and natural gas reserves to help investors evaluate their investments in oil and gas companies. The amendments are also designed to modernize the oil and natural gas disclosure requirements to align them with current practices and technological advances. Revised requirements in the final rule include, but are not limited to:

- Oil and natural gas reserves must be reported using a 12-month average of the closing prices on the first day of each of such months, rather than a single day year-end price;
- Companies will be allowed to report, on a voluntary basis, probable and possible reserves, previously prohibited by SEC rules; and
- Easing the standard for the inclusion of proved undeveloped reserves ("PUDs") and requiring disclosure of information indicating any progress toward the development of PUDs.

We began complying with the disclosure requirements in our annual report on Form 10-K for the year ended December 31, 2009. Under the SEC rules, our year-end 2009 reserve report uses the new rules as a change in accounting principle that is inseparable form a change in estimates. Under the SEC's final rule, prior period reserves were not restated. The impact of the adoption of the SEC final rule on our financial statements is not practicable to estimate due to the operational and technical challenges associated with calculating a cumulative effect of adoption by preparing reserve reports under both the old and new rules.

In June 2009, the Financial Accounting Standards Board ("FASB") released the final version of its new Accounting Standards Codification (the "Codification") as the single authoritative source for U.S. GAAP. The Codification replaces all previous U.S. GAAP accounting standards as described in ASC 105 (SFAS 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles)*. While not intended to change U.S. GAAP, the Codification significantly changes the way in which the accounting literature is organized. It is structured by accounting topic to help accountants and auditors more quickly identify the guidance that applies to a specific accounting issue. However, because the Codification completely replaces existing standards, it will affect the way U.S. GAAP is referenced by companies in their financial statements and accounting policies. The Codification is effective for financial statements that cover interim and annual periods ending after September 15, 2009. The adoption of the Codification did not have a material impact on our financial statements.

In May 2009, the FASB established general standards of accounting for and the disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that currently exist in the auditing standards. The standard, which includes a new required disclosure of the date through which an entity has evaluated subsequent events, is effective for interim or annual periods ending after June 15, 2009. We perform an evaluation of subsequent events until the issuance date of our document with the SEC so the adoption of the new requirements had no impact on our financial statements. See Note 17 for additional information.

In June 2008, the FASB addressed whether instruments granted in unit-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per unit under the two-class method. This affects entities that accrue or pay nonforfeitable distributions on unit-based payment awards during the awards' service period. Effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years, a retrospective adjustment to all prior period earnings per unit calculations was required. We adopted the guidance on January 1, 2009, and began including all unvested restricted common units that earn distributions in earnings per unit calculations for all periods presented. The adoption of this guidance did not have a material impact on our earnings per unit calculations.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

In March 2008, the Emerging Issues Task Force reached a consensus on how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. Beginning after December 15, 2008, and interim periods within those fiscal years, this guidance was to be applied retrospectively for all financial statements presented. Earlier application was not permitted. The adoption of this guidance did not have a material impact on our financial statements.

In March 2008, the FASB issued guidance that was effective beginning January 1, 2009 and required entities to provide expanded disclosures about derivative instruments and hedging activities including (1) the ways in which an entity uses derivatives, (2) the accounting for derivatives and hedging activities, and (3) the impact that derivatives have (or could have) on an entity's financial position, financial performance, and cash flows. This guidance only required expanded disclosures and did not change the accounting for derivatives. The adoption of this guidance did not have a material impact on our financial statements. See Note 3 for additional information.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2010, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. We are currently reviewing the recently issued standards and interpretations but none are expected to have a material impact on our financial statements.

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 $5.9 million. 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 $5.9 million, which consisted of $5.9 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	$ 5.9
Total assets acquired	5.9
Asset retirement obligations	(0.0)
Net assets acquired	$ 5.9

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. This purchase price allocation is preliminary and remains subject to post-closing adjustments during 2011.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Cola Acquisition

On March 31, 2008, we acquired 83 non-operated producing natural gas wells in the Woodford Shale in the Arkoma Basin in Oklahoma from CoLa Resources LLC (“CoLa”) for $50.2 million, including purchase price adjustments (“CoLa Acquisition”). CoLa is an affiliate of CEG, our former sponsor. The transaction was reviewed and approved by our conflicts committee. In its review, our conflicts committee considered various economic factors (including historical and estimated future production, estimated proved reserves, future pricing estimates and operating cost estimates) regarding the transaction, and determined that the acquisition was fair and in the best interests of the Company. The 83 wells, located in Coal and Hughes Counties, Oklahoma, have an average gross working interest per well of 11.4% and an average net revenue interest per well of 9.2%. The acquired natural gas reserves associated with the wells are 100% proved developed producing. Our results of operations include the results of the non-operated wells after the date of acquisition.

To fund the purchase of CoLa, we borrowed $53.0 million under our previous reserve-based credit facilities.

Upon the announcement of the acquisition, we entered into derivative transactions to hedge a portion of the future expected production associated with these wells.

The total consideration paid was $50.1 million, which consisted of $50.2 million in cash and transaction costs and assumed liabilities of approximately $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 March 31, 2008	(in millions)
Oil and Natural Gas Properties	$ 50.2
Total assets acquired	50.2
Asset retirement obligations	(0.1)
Net assets acquired	$ 50.1

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.

In July 2009, we received approximately $0.2 million from Cola for post-closing and title adjustments related to the CoLa acquisition. Under the purchase agreement, we had the right to assert, and CoLa had the right to attempt to cure, any title defects to the acquired wells until July 31, 2009. CoLa’s post-closing payment obligations with respect to title defects and indemnities under the purchase agreement was secured, in part, by a guaranty from CCG delivered at closing. The maximum amount of the CCG guaranty was limited to (i) 20% of the purchase price, with respect to indemnity obligations, and (ii) with respect to title defect obligations, the amount of such title defects, such amount to be calculated as provided in the purchase agreement. The amount of CCG’s guaranty with respect to title defect obligations has decreased as title curative were received and as CoLa received proceeds of production from the wells as to which payments of production proceeds had not commenced as of the closing date and which were attributable to periods prior to the effective time of the purchase agreement. No further title adjustments are expected and a guarantee no longer exists with respect to title defect obligations.

3. DERIVATIVE AND FINANCIAL INSTRUMENTS

Mark-to-Market Activities

We have hedged a portion of our expected natural gas sales from currently producing wells through December 2014. All of our swaps and basis swaps were accounted for as mark-to-market activities as of December 31, 2010.

At December 31, 2010, and December 31 2009, we had debt outstanding of $165.0 million and $195.0 million, respectively, under our reserve-based credit facility. We have 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 outstanding debt for various maturities extending through October 2014. All of our interest rate swaps are accounted for as mark-to-market activities as of December 31, 2010. Prior to February 2009, they were accounted for as cash flow hedges.

For 2010 and 2009, we recognized mark-to-market gains of approximately $42.1 million and $19.4 million, respectively, in connection with our commodity derivatives. At December 31, 2010 and December 31, 2009, the fair value of the derivatives accounted for as mark-to-market activities amounted to a net asset of approximately $83.4 million and a net asset of approximately $58.0 million, respectively.

Accumulated Other Comprehensive Income

Prior to the first quarter of 2009, we accounted for certain 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 $10.9 million and an unrecognized gain of $28.4 million at December 31, 2010 and December 31, 2009, 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, 2011	$ 724	$ (24)	$ 700
June 30, 2011	1,960	(75)	1,885
September 30, 2011	1,749	(74)	1,675
December 31, 2011	1,283	(60)	1,223
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	$ 11,354	$ (434)	$ 10,920

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.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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 commodity 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. Certain of our derivatives are classified as Level 3 because observable market data is not available for all of the time periods for which we have derivative instruments. As observable market data becomes available for all of the time periods, these derivative positions will be reclassified 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, 2010, and December 31, 2009.

At December 31, 2010	Level 1	Level 2	Level 3	Netting and Cash Collateral*	Total Fair Value
			(In 000’s)		
Risk management assets	$ —	$87,072	$(3,573)	$ —	$83,499
Risk management liabilities	—	(141)	—	—	(141)
Total	$ —	$86,931	$(3,573)	$ —	$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.*

At December 31, 2009	Level 1	Level 2	Level 3	Netting and Cash Collateral*	Total Fair Value
			(In 000’s)		
Risk management assets	$ —	$62,894	$(4,727)	$ —	$58,167
Risk management liabilities	—	(208)	—	—	(208)
Total	$ —	$62,686	$(4,727)	$ —	$57,959

* *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.

We use observable market data or information derived from observable market data in order to determine the fair value amounts presented above. Prior to September 30, 2009, the valuation of our derivatives was performed by Constellation under a management services agreement (see Note 7). In order to determine the fair value amounts presented above, Constellation utilized various factors, including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. These factors included not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and parental guarantees), but also the impact of our nonperformance risk on our liabilities. We currently use our reserve-based credit facility to provide credit support for our derivative transactions. Historically, in connection with certain of our acquisitions, we have used guarantees from Constellation to provide credit support for our derivative transactions associated with the acquisition volumes. 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 assets from counterparties. 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. At December 31, 2009, the impact of non-performance credit risk on the valuation of our assets from counterparties was $0.6 million, of which $0.1 million was reflected as an increase to our non-cash market-to-market gain and $0.7 million was reflected as a reduction to our accumulated other comprehensive income.

We use observable market data or information derived from observable market data to measure the fair value of our derivative instruments. Prior to September 30, 2009, in certain instances, Constellation may have utilized internal models to measure the fair value of our derivative instruments. Generally, Constellation used similar models to value similar instruments. Valuation models utilized various inputs which included quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that were not active, other observable inputs for the assets or liabilities, and market-corroborated inputs, which were inputs derived principally from or corroborated by observable market data by correlation or other means.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The following table sets forth a reconciliation of changes in the fair value of risk management assets and liabilities classified as Level 3 in the fair value hierarchy:

	Three Months Ended December 31, 2010 (In 000's)	Twelve Months Ended December 31, 2010 (In 000's)
Balance at beginning of period	$ (5,512)	$ (4,727)
Realized and unrealized gain (loss):		
Included in earnings	1,308	(3,078)
Included in other comprehensive income	—	389
Purchases, sales, issuances, and settlements	631	3,843
Transfers into and (out of) Level 3	—	—
Balance as of December 31, 2010	$ (3,573)	$ (3,573)
Change in unrealized gains relating to derivatives still held as of December 31, 2010	$ 1,308	$ (2,689)

	Three Months Ended December 31, 2009 (In 000's)	Twelve Months Ended December 31, 2009 (In 000's)
Balance at beginning of period	$ (6,168)	$ 6,752
Realized and unrealized gain (loss):		
Included in earnings	(3,084)	(12,923)
Included in other comprehensive income	2,941	1,630
Purchases, sales, issuances, and settlements	1,584	5,349
Transfers into and (out of) Level 3[(a)]	—	(5,535)
Balance as of December 31, 2009	$ (4,727)	$ (4,727)
Change in unrealized gains (losses) relating to derivatives still held as of December 31, 2009	$ (143)	$ (1,872)

	Three Months Ended December 31, 2008 (In 000's)	Twelve Months Ended December 31, 2008 (In 000's)
Balance at beginning of period	$ (1,137)	$ (3,591)
Realized and unrealized gains (loss):		
Included in earnings	8,228	10,464
Included in other comprehensive income	14,533	16,654
Purchases, sales, issuances, and settlements	(3,981)	(5,884)
Transfers into and (out of) Level 3[(a)]	(10,891)	(10,891)
Balance as of December 31, 2008	$ 6,752	$ 6,752
Change in unrealized gains (losses) relating to derivatives still held as of December 31, 2008	$ 19,032	$ 20,404

(a) Reflects transfers of derivatives from Level 3 to Level 2 because observable market data is available for all time periods for which we have derivative instruments.

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Fair Value of Financial Instruments

At December 31, 2010, 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.

The following fair value disclosures are applicable to our financial statements as of December 31, 2010, and 2009:

		Fair Value of Asset/ (Liability) on Balance Sheet (in 000's)	
Derivative Type	**Location of Asset/ (Liability) on Balance Sheet**	**Year Ended December 31, 2010**	**Year Ended December 31, 2009**
Commodity-MTM	Risk management assets-current	$ 38,945	$ 30,292
Commodity-MTM	Risk management assets-non-current	60,324	47,285
Commodity-MTM	Risk management assets-current	(2,432)	(6,041)
Commodity-MTM	Risk management assets-non-current	$ (9,765)	$ (8,642)
Commodity-MTM	Risk management liabilities-current	(141)	(208)
Interest Rate-MTM	Risk management assets-non-current	(3,573)	(4,727)
	Total	$ 83,358	$ 57,959

		Amount of Gain/(Loss) in Income (in 000's)	
Derivative Type	**Location of Gain/(Loss) in Income**	**Quarter Ended December 31, 2010**	**Quarter Ended December 31, 2009**
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ (10,464)	$ 15,743
Commodity-MTM	Oil and gas sales	7,978	1,217
Interest Rate-MTM	Interest expense-Gain/(Loss) from mark-to-market activities	1,939	218
Interest Rate-MTM	Interest expense	(631)	(361)
	Total	$ (1,178)	$ 16,817

		Amount of Gain/(Loss) in Income (in 000's)	
Derivative Type	**Location of Gain/(Loss) in Income**	**Year Ended December 31, 2010**	**Year Ended December 31, 2009**
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ 41,368	$ 16,572
Commodity-MTM	Oil and gas sales	23,011	$ 13,141
Interest Rate-MTM	Interest expense-Gain/(Loss) from mark-to-market activities	765	(1,397)
Interest Rate-MTM	Interest expense	(3,454)	(476)
	Total	$ 61,690	$ 27,840

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Derivative Type	Location of Gain/(Loss) for Effective and Ineffective Portion of Derivative in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income—Effective (in 000's) Quarter Ended December 31, 2010	Quarter Ended December 31, 2009	Amount of Gain/(Loss) in Income—Ineffective (in 000's) Quarter Ended December 31, 2010	Quarter Ended December 31, 2009
Commodity-Cash Flow	Gain/(Loss) from mark-to-market activities	$ 713	$ 2,838	$ —	$ —
Commodity-Cash Flow	Oil and gas sales	3,568	9,920	—	—
Interest Rate-Cash flow	Gain/(Loss) from mark-to-market activities	—	(2,941)	—	—
Interest Rate-Cash Flow	Interest expense	—	(1,222)	—	—
	Total	$ 4,281	$ 8,595	$ —	$ —

Derivative Type	Location of Gain/(Loss) for Effective and Ineffective Portion of Derivative in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income—Effective (in 000's) Year Ended December 31, 2010	Year Ended December 31, 2009	Amount of Gain/(Loss) in Income—Ineffective (in 000's) Year Ended December 31, 2010	Year Ended December 31, 2009
Commodity-Cash Flow	Gain/(Loss) from mark-to-market activities	$ 713	$ 2,838	$ —	$ —
Commodity-Cash Flow	Oil and gas sales	17,341	46,730	—	267
Interest Rate-Cash flow	Gain/(Loss) from mark-to-market activities	—	(2,941)	—	—
Interest Rate-Cash Flow	Interest expense	(389)	(4,335)	—	—
	Total Cash Flow	$ 17,665	$ 42,292	$ —	$ 267

As of December 31, 2010, we have interest rate swaps on $93.0 million of outstanding debt for various maturities extending through October 2014, various commodity swaps for 33,540,000 MMbtu of natural gas production through December 2014, and various basis swaps for 21,109,512 MMbtu of natural gas production in the Cherokee Basin through December 2014.

Credit Support Fee Agreements

In connection with our acquisitions during 2008 and 2007, Constellation entered into credit support agreements with us to provide guarantees to three banks that required credit support for certain financial derivatives. These guarantees were obtained because we did not own the assets at the time the derivatives were entered into and we could not use our existing reserve-based credit facilities to provide collateral for the derivative transactions. All of these guarantees have expired. For the period ended December 31, 2008, Constellation charged us $0.8 million for this credit support.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

4. DEBT

Reserve-Based Credit Facility

On November 13, 2009, we entered into an amended and restated $350.0 million reserve-based credit facility with The Royal Bank of Scotland plc as administrative agent and a syndicate of lenders. The reserve-based credit facility amends, extends, and consolidates our previous reserve-based credit facilities and matures on November 13, 2012. 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%), Wells Fargo Bank, N.A. (14.63%), and Societe Generale (14.63%).

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, 2010, our borrowing base was $195.0 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, together with, 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 2011. 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, 2010, 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 (defined as, 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 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. 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.

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 February 25, 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 our relationship with Constellation or Constellation’s right to appoint all of the Class A managers of our board of managers.

Debt Issue Costs

As of December 31, 2010, our unamortized debt issue costs were approximately $3.7 million. These costs are being amortized over the life of the reserve-based credit facility through November 2012.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Funds Available for Borrowing

As of December 31, 2010, we had $165.0 million in outstanding debt under our reserve-based credit facility and $30.0 million in remaining borrowing capacity. As of December 31, 2009, we had $195.0 million in outstanding debt under our reserve-based credit facilities.

Compliance with Financial Covenants

At December 31, 2010, 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, 2010, our actual Total Net Debt to annual Adjusted EBITDA ratio was 2.9 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 3.2 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 9.2 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 the borrowing base below its current level of $195.0 million at one of the future redeterminations by the lenders. During 2011, we intend to use 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 further reduce capital expenditures, continue to suspend our quarterly distributions to unitholders, sell oil and natural gas properties, liquidate in-the-money derivative positions, further 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, 2011, will become a current liability.

5. OIL AND NATURAL GAS PROPERTIES

Natural gas properties consist of the following:

	December 31, 2010	December 31, 2009 (In 000's)	December 31, 2008
Oil and natural gas properties and related equipment (successful efforts method)			
Property (acreage) costs			
Proved property	$ 772,450	$ 756,461	$ 729,898
Unproved property	698	37,147	38,293
Total property costs	773,148	793,608	768,191
Materials and supplies	2,073	4,312	4,587
Land	912	912	912
Total	776,133	798,832	773,690
Less: Accumulated depreciation, depletion, amortization and impairments	(499,214)	(186,207)	(111,171)
Natural gas properties and equipment, net	$ 276,919	$ 612,625	$ 662,519

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Depletion, depreciation, amortization and impairments consisted of the following:

	Twelve Months Ended December 31, 2010	Twelve Months Ended December 31, 2009	Twelve Months Ended December 31, 2008
		(In 000's)	
DD&A of oil and natural gas-related assets	$ 85,263	$ 71,173	$ 52,281
Asset impairments	272,487	5,113	25,638
Total	$ 357,750	$ 76,286	$ 77,919

Impairment of Oil and Natural Gas Properties and Other Non-Current Assets

In 2010, due to a significant decline in future natural gas price curves across all future production periods, we performed an impairment analysis of our oil and natural gas properties and other non-current assets. For the twelve months ended December 31, 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. These non-cash charges are included in asset impairments in the Consolidated Statement of Operations. 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 have no impact on our cash flows, liquidity position, or debt covenants. If expected future oil and natural gas prices continue to decline during 2011, the estimated undiscounted future cash flows for our proved oil and natural gas properties may not exceed the net capitalized costs for our properties in the Cherokee Basin or in the Woodford Shale and a non-cash impairment charge may be required to be recognized in future periods. 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.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

In 2009, we recorded a charge of approximately $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 charge is included in depreciation, depletion and amortization in the Consolidated Statement of Operations. 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.

In 2008, we recorded a charge of $25.7 million to impair the value of our 83 well bores located in the Woodford Shale in Oklahoma. This charge is included in depreciation, depletion and amortization in the Consolidated Statement of Operations. This impairment was recorded because the carrying value of the asset exceeded the fair value of the asset 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 production volumes than originally estimated, a higher initial production decline rate, and lower future expected natural gas prices. Cash flow estimates for the impairment testing exclude derivative instruments. As of December 31, 2008, 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 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.

In 2008, we sold an international pulling unit, a trencher, and other miscellaneous equipment for approximately $0.2 million and recorded a gain of approximately $0.1 million on the sales.

Involuntary Conversion

In 2008, a fire damaged our field office located in Dewey, Oklahoma. The net book value of the building was $0.2 million. A gain of $0.2 million was recorded for the involuntary conversion as the insurance proceeds of $0.4 million exceeded the book value of the building.

Useful Lives

Our furniture, fixtures, and equipment are depreciated over a life of one to five 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.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Exploration and Dry Hole Costs

Our exploration and dry hole costs were $0.8 million, $0.9 million, and $0.4 million in 2010, 2009, and 2008, 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, $0.4 million, and $0.1 million for the years ended December 31, 2010, 2009, and 2008 respectively.

7. RELATED PARTY TRANSACTIONS

Management Services Agreement

In November 2006, we entered into a management services agreement with Constellation Energy Partners Management, LLC ("CEPM"), a subsidiary of Constellation, to provide certain management, technical and administrative services. CEPM terminated the management services agreement effective December 15, 2009. Each quarter, CEPM charged us an amount for services provided to us. This amount was agreed to annually and included a portion of the compensation paid by CEPM 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 and $2.9 million for the year ended December 31, 2009 and 2008, respectively.

We had payables to Constellation of $0.2 million and $1.0 million as of December 31, 2009 and 2008, respectively. This payable balance is included in current liabilities in the accompanying balance sheets.

Credit Support Fee Agreements

As described further in Note 3, during 2008 and 2007, we entered into credit support fee agreement with CEG under which CEG guaranteed credit support for certain financial derivatives with three financial institutions. These credit support fee agreement have expired. For the period ended December 31, 2008, CEG charged us $0.8 million for the credit support.

Natural Gas Purchases

Through March 31, 2009, CCG purchased natural gas from us in the Cherokee Basin. 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, and December 31, 2008, CCG paid us $5.7 million and $24.1 million for natural gas purchases, respectively.

Management Incentive Interests

CEPM holds the 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. For the twelve months ended December 31, 2010, none of these applicable tests have been met, and, as a result, CEPM was not entitled to receive any management incentive interest distributions. Through December 31, 2008, a cash reserve of $0.7 million had been established to fund future distributions on the management incentive interests. In February 2009, we reduced our distribution rate to $0.13 per unit. This decrease in the distribution rate terminated the initial management incentive interest vesting period. After the February 13, 2009 distribution was paid, the reserve was reduced to zero.

CoLa Acquisition

As further described in Note 2, on March 31, 2008, we acquired 83 non-operated producing oil and natural gas wells in the Woodford Shale in the Arkoma Basin in Oklahoma from CoLa for approximately $50.2 million, including purchase price adjustments through December 31, 2008. CoLa is an affiliate of CEG, our former sponsor. The transaction was reviewed and approved by our conflicts committee. In its review, our conflicts committee considered various economic factors (including historical and estimated future production, estimated proved reserves, future pricing estimates and operating cost estimates) regarding the transaction, and determined that the transaction was fair to and in the best interests of the Company.

At December 31, 2010 and 2009, we had a payable to CCG of less than $0.1 million and $0.4 million, respectively, for revenues and tax credits received for time periods when CCG owned the 83 well bores. These payable balances are included in current liabilities in the accompanying balance sheets.

Equity Contributions

During the year ended December 31, 2008, CEPM agreed to waive payment in cash of its third quarter 2008 fees to be billed to us in an amount equal to one-half of our incurred fees and expenses in connection with the Torch arbitration, up to a maximum of $0.6 million. CEPM has also agreed to waive payment in cash of its third quarter 2008 fees of $0.25 million for costs associated with the retention of a strategic advisor.

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. As of December 31, 2010, December 31, 2009, and December 31, 2008, other than the matters discussed below, 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.

Certain of our wells in the Robinson’s Bend Field are subject to a net profits interest (“NPI”) held by Torch Energy Royalty Trust (the “Trust”) (See Note 10). The royalty payment to the Trust is calculated using a sharing arrangement with a pricing formula that has had the effect of keeping our payments to the Trust lower than if such payments had been calculated based on prevailing market prices. We are uncertain of the financial impact of the NPI over the life of the Robinson’s Bend Field as it has volumetric and price risk variables. However, in order to address a portion of the risk of the potential adverse impact on our operating results from a termination of the sharing arrangement, Constellation Holdings, Inc. (“CHI”) contributed $8.0 million to us in exchange for all of our Class D interests at the closing of its initial public offering in November 2006 for the purpose of partially protecting the distributions to the common unit holders in the event the sharing arrangement is terminated. This contribution will be returned to CHI in 24 special quarterly distributions as long as the sharing agreement remains in effect for the distribution period. As discussed in Note 10 and Note 17, the Class D interest special quarterly distributions have been suspended for all quarters commencing on or after January 1, 2008. This suspension includes approximately $3.6 million which represents the distributions that were suspended for the

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

quarterly periods ended September 30, June 30, and March 31, 2010, and December 31, September 30, June 30, and March, 31, 2009, and December 31, September 30, June 30, and March 31, 2008. Including the suspended distributions, the remaining undistributed amount of the Class D interests is $6.7 million. See Note 17 for additional information.

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's recorded by us relate 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, 2010	December 31, 2009	December 31, 2008
		(In 000's)	
Asset retirement obligation, beginning balance	$ 12,129	$ 6,754	$ 6,163
Liabilities incurred from acquisition of the properties (Note 2)	32	—	56
Liabilities incurred	83	3,873	124
Liabilities settled	(42)	(12)	—
Revisions to prior estimates	—	1,108	—
Accretion expense	822	406	411
Asset retirement obligation, ending balance	$ 13,024	$ 12,129	$ 6,754

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 2010, 2009, and 2008, 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 are subject to a non-operating NPI. The holder of the NPI, the Trust, does not have the right to receive production from the applicable wells in the Robinson's Bend Field. Instead, the Trust only has the right to receive a specified portion of the future natural gas sales revenues from specified wells as defined by the Net Overriding Royalty Conveyance Agreement. We record the NPI as an overriding royalty interest net in revenue in the Consolidated Statements of Operations.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Amounts due to the Trust with respect to NPI are comprised of the sum of the Net Proceeds and the Infill Net Proceeds, which are described below.

The Net Proceeds equal the lesser of (i) 95% of the net proceeds from 393 producing wells in the Robinson's Bend Field and (ii) the net proceeds from the sale of 912.5 MMcf of natural gas for the quarter. Net proceeds equal gross proceeds, currently calculated by reference to the gas purchase contract, less specified costs attributable to the Robinson's Bend Assets. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (i) of the first sentence of this paragraph (the NPI Net Proceeds Calculation) include: (a) delay rentals, shut-in royalties and similar payments, (b) property, production, severance and similar taxes and related audit charges, (c) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies, (d) certain liabilities for environmental damage, personal injury and property damage, (e) certain litigation costs, (f) costs of environmental compliance, (g) specified operating costs incurred to produce hydrocarbons, (h) specified development costs (including costs to increase recoverable reserves or the timing of recovery of such reserves), (i) costs of specified lease renewals and extensions and unitization costs and (j) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (ii) of the first sentence of this paragraph include: (a) property, production, severance and similar taxes, (b) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies and (c) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. Net proceeds are calculated quarterly and any negative balance (expenses in excess of revenues) within the "net proceeds" calculation accumulates and is charged interest as described above.

The cumulative "Net NPI Proceeds" balance must be greater than $0 before any payments are made to the Trust. The cumulative Net Proceeds was a deficit for the twelve months ended December 31, 2010 and 2009. As a result, no payments were made to the Trust with respect to the NPI for the twelve months ended December 31, 2010 and 2009. The calculation of the Infill Net Proceeds uses the same methodology as the NPI Net Proceeds Calculation described above except that the proceeds and costs are attributable not to the NPI Net Proceeds Wells, but to the remaining wells in the Robinson's Bend Field that are subject to the NPI and that have been drilled since the Trust was formed and wells that will be drilled (other than wells drilled to replace damaged or destroyed wells), in each case on leases subject to the NPI. The NPI in the Infill Wells entitles the Trust to receive 20% of the Infill Net Proceeds. There has never been a payout on the Infill Net Proceeds.

The Gas Purchase Contract

A gas purchase contract was executed in connection with the formation of the Trust in 1993, which established a minimum price for the purchase of the gas from the Trust Wells, as well as, a sharing arrangement when the applicable index price for gas increased over a specified sharing price. Torch Energy Marketing, Inc., an affiliate of the original sponsor of the Trust ("TEMI") as buyer, and another affiliate of TEMI, as seller, entered into the gas purchase contract pursuant to which the parties were obligated to purchase and sell, as the case may be, all net production attributable to the properties subject to the NPI, including the Trust Wells, for an amount equal to the greater of (a) the minimum price of $1.70 per MMBtu, adjusted for inflation, and (b) 97% of a specified index price for natural gas, less certain specified permitted deductions for gathering, treating and transportation that are calculated monthly. The index price for Black Warrior Basin production equals the SONAT Inside FERC price. In addition, if 97% of the index price exceeds the sharing price specified in the gas purchase contract as adjusted for inflation, which we refer to as the sharing price, the purchase price for the gas is equal to the sharing price plus 50% of the difference between 97% of the index price and the sharing price. As a

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

result, the purchaser is entitled to retain 50% of that difference between 97% of the index price and sharing price. The sharing price was $2.43, $2.40, $2.30, $2.26, $2.22, and $2.18 per MMBtu in 2010, 2009, 2008, 2007, 2006, and 2005, respectively. Despite increases in spot prices for natural gas in certain years, the sharing arrangement under the gas purchase contract has had the effect of keeping the payments to the Trust significantly lower than if the NPI were calculated using the prevailing market price for production from the Trust Wells.

In connection with the acquisition of our initial properties in the Black Warrior Basin from Everlast, our subsidiary, Robinson's Bend Marketing II, LLC (now merged into our subsidiary Robinson's Bend Operating II, LLC), assumed TEMI's obligations under the gas purchase contract and our subsidiary, Robinson's Bend Production II, LLC ("RBP"), assumed the TEMI affiliate's obligations under the gas purchase contract, in each case in respect of the Black Warrior Basin for production from and after June 13, 2005. As a result, we were obligated to sell and to purchase all production from the Trust Wells on the terms and conditions set forth in the gas purchase contract until termination of the gas purchase contract on January 29, 2008.

Termination of the Trust and Gas Purchase Contract

On January 29, 2008, the unitholders of the Trust voted to terminate the Trust and the trust agreement and authorized the Trustee to wind up, liquidate and distribute the assets held by the Trust under the terms of the trust agreement. The gas purchase contract, by its terms, was also terminated on January 29, 2008 as a result of the termination of the Trust. With the gas purchase contract terminated, we are no longer obligated to sell gas produced from our interest in the Black Warrior Basin pursuant to the gas purchase contract. Notwithstanding the termination of the gas purchase contract, the NPI will continue to burden the Trust Wells, and it should continue to be calculated as if the gas purchase contract were still in effect, regardless of what proceeds may actually be received by us as the seller of the gas. As a result of the termination of the Trust, certain water gathering, separation and disposal costs, which are a component of the NPI calculation, increased from $0.53 per barrel to $1.00 per barrel pursuant to the Water Gathering and Disposal Agreement dated August 9, 1990, as amended; the amounts of the water gathering, separation and disposal costs are set forth in such agreement.

Litigation Related to Trust Termination

On January 25, 2008, Torch Royalty Company, Torch E&P Company, and CEP (collectively, the "Claimants") commenced an arbitration proceeding before Judicial Arbitration and Mediation Services against Wilmington Trust Company, as Trustee ("Trustee") for the Trust, and to Capital One, NA, as successor to Hibernia National Bank, as trustee for Torch Energy Louisiana Royalty Trust, pursuant to the operative dispute resolution provisions of the agreement governing the Trust, the NPI and the Conveyances (as defined below). The Claimants were working interest owners in certain oil and gas fields located in Texas, Louisiana and Alabama. The working interests owned by the other Claimants were similarly subject to net profit interests (the "Other NPIs") that were also based on the gas purchase contract. The Claimants sought a declaratory judgment that the NPI payments as well as the payments owed in respect of the Other NPIs will continue to be calculated using the sharing arrangement under the gas purchase contract even though the Trust and the gas purchase contract were terminated. The Trustee took the position that the sharing arrangement under the gas purchase contract terminated upon the termination of the gas purchase contract. Trust Venture Company, LLC ("Trust Venture") was permitted to intervene in the proceeding under an agreement whereby Trust Venture and its affiliates agreed to be bound by the formal award in the proceeding. On July 18, 2008, the arbitration panel issued its final award which, among other things, found and concluded that the sharing arrangement and other pricing terms of the gas purchase contract will continue to control the amount owed to the holder of the NPI, and on December 10, 2008, the District Court of Harris County, Texas, 152nd Judicial District, dismissed the appeal of the final award filed by the Trustee and Trust Venture and confirmed the final award.

On January 8, 2009, we were served by Trust Venture, on behalf of the Trust, with a purported derivative action filed in Alabama state court demanding an audited statement of revenues and expenses associated with the NPI, alleging a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserting that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit seeks unspecified damages and an accounting of the NPI. The Alabama court has made the Trust a nominal party to the Alabama litigation. On August 18, 2009, Trust Venture filed an application for preliminary injunction requesting that the Alabama court enter an injunction requiring the Company to deposit into an escrow account all fees, less expenses, that it receives from water disposal under the Water Gathering and Disposal Agreement pending judgment in the lawsuit and asserting damages of approximately $11.6 million from June 2005 to May 2009. These alleged damages appear to be calculated based on a water gathering, separation and disposal fee of $0.05 per barrel notwithstanding the provisions of the Water Gathering and Disposal Agreement. After hearing, the Alabama court denied Trust Venture's application. On February 9, 2010, Trust Venture filed a motion for partial summary judgment seeking a determination regarding the applicability of a provision in the Conveyance related to the calculation of water handling charges, which motion the court denied on May 28, 2010, with the court ruling that our position with respect to the Conveyance provision was correct.

See Note 17 for additional information.

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, 2010, we had no accrued environmental obligations. As of December 31, 2009, accrued environmental obligations were $0.2 million. This obligation was classified as a current liability on our Consolidated Balance Sheet.

12. UNIT-BASED COMPENSATION

We recognized approximately $1.8 million and $1.3 million of expense related to our unit-based compensation plans in the twelve months ended December 31, 2010, and December 31, 2009, respectively. As of December 31, 2010, we had approximately $4.2 million in unrecognized compensation expense related to our unit-based compensation plans expected to be recognized through the first quarter of 2015.

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.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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 will vest in full 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 expect those granted to our three independent managers which vested in full in March 2010.

Prior to vesting, these restricted common units do not have the right to receive distributions paid by us on our common units. Instead, each such unvested restricted common unit carries the right to receive distribution credits when any distributions are 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 have been issued as distribution credits.

Until the notional units granted under 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% will vest on January 1, 2011.

Prior to vesting, these restricted common units do not have the right to receive distributions paid by us on our common units. Instead, each such unvested restricted common unit carries the right to receive distribution credits when any distributions are 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 have been issued as distribution credits.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

2008 Grants

Grants under the Long-Term Incentive Program

We granted 23,232 restricted common unit awards under the LTIP on August 1, 2008, to certain field employees in Alabama and Oklahoma. These units had a total fair market value of approximately $425,000 based on the average of the high and low trading price of our common units on NYSE Arca on the grant date. These service-based restricted units will vest on a three year ratable schedule beginning on August 1, 2009.

We granted 11,004 restricted common unit awards under the LTIP on March 1, 2008, to the independent, non-employee members of the board of managers. These units had a total fair market value of approximately $225,000 at the grant date. These service-based restricted units vested in full on March 1, 2009.

13. DISTRIBUTIONS TO UNITHOLDERS

Distributions through December 31, 2010

Beginning in June 2009, we have suspended our quarterly distributions to unitholders. For the quarter ended September 30, 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. See Note 17 for additional information.

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.

Distributions through December 31, 2008

On November 14, 2008, we paid a distribution for the third quarter of 2008 to the unitholders of record at November 7, 2008. The distribution was paid to holders of common units and Class A units at a rate of $0.5625 per unit.

On August 14, 2008, we paid a distribution for the second quarter 2008 to the unitholders of record at August 7, 2008. The distribution was paid to holders of common units and Class A units at a rate of $0.5625 per unit.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

On May 15, 2008, we paid a distribution for the first quarter of 2008 to the unitholders of record at May 8, 2008. The distribution was paid to holders of common units and Class A units at a rate of $0.5625 per unit.

On February 14, 2008, we paid a distribution for the fourth quarter of 2007 to the unitholders of record at February 7, 2008. The distribution was paid to holders of common units and Class A units at a rate of $0.5625 per unit. A distribution of $0.3 million was paid to the holder of the Company's Class D interests on February 14, 2008.

14. MEMBERS' EQUITY

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. See Note 17 for additional information.

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.

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.

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.

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 under our 2009 Omnibus Incentive Compensation Plan.

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.

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.

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.

2008 Equity

At December 31, 2008, we had 447,721 Class A units and 21,938,342 Class B units outstanding, which included 34,236 restricted unvested common units. We have authorized 447,721 Class A units and 23,348,763 Class B units.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

At December 31, 2008, we had granted 39,579 units of the 450,000 units available under our Long-Term Incentive Plan. Of these grants, 5,343 have vested and 34,236 are unvested.

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, 2010, 2009, and 2008:

	December 31, 2010	December 31, 2009	December 31, 2008
		(In 000's)	
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	$ 772,450	$ 756,461	$ 729,898
Unproved property	698	37,147	38,293
Total property costs	773,148	793,608	768,191
Materials and supplies	2,073	4,312	4,587
Land	912	912	912
Total	776,133	798,832	773,690
Less: Accumulated depreciation, depletion, amortization and impairments	(499,214)	(186,207)	(111,171)
Net capitalized cost	$ 276,919	$ 612,625	$ 662,519

(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.

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The following table sets forth costs incurred for oil and natural gas producing activities for the years ended December 31, 2010, 2009, and 2008:

	For the year ended December 31, 2010	For the year ended December 31, 2009	For the year ended December 31, 2008
		(In 000's)	
Costs incurred for the period:			
Acquisition of properties			
Proved	$ 5,691	$ 170	$ 47,665
Unproved	678	121	398
Development costs	7,973	22,913	47,897
Total costs incurred	$ 14,342	$ 23,204	$ 95,960

The development costs for the years ended December 31, 2010, 2009, and 2008 primarily represent costs to develop our proved undeveloped reserves. During 2010, substantially all of our development expenditures were for locations in the Cherokee Basin that were not included as proved undeveloped reserves in our 2009 SEC reserve report because they were uneconomic at the SEC-required price. We estimate that we will spend $7.2 million, $20.5 million, and $18.5 million to develop our proved undeveloped reserves in 2011, 2012, and 2013, respectively.

Our exploration and dry hole costs were $0.8 million, $0.9 million, and $0.4 million in 2010, 2009, and 2008, 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. 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, 2010	For the year ended December 31, 2009	For the year ended December 31, 2008
		(In MMcfe)	
Beginning Balance	131,180	232,414	302,787
Extensions and discoveries	226	1,103	5,628
Purchases of reserves in place	805	—	12,738
Sales of reserves in place	—	—	—
Revisions of previous estimates	49,027	(85,276)	(71,355)
Production	(12,231)	(17,061)	(17,384)
Ending Balance	169,007	131,180	232,414
Total proved developed reserves	127,627	112,059	159,027

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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 2010 and 2009 reserve estimates were prepared in accordance with the new FASB and SEC rules for oil and gas reporting effective at December 31, 2009 using the SEC-required price. Our 2008 reserve estimates were prepared using year-end pricing for the respective period.

Our 2010, 2009 and 2008 proved reserve estimates were 169.0 Bcfe, 131.2 Bcfe and 232.4 Bcfe. For these years, NSAI, an independent petroleum engineering firm, prepared an estimate of our proved reserves. NSAI's estimates of our 2010, 2009 and 2008 proved reserves were used to prepare our financial statements.

Our 2010 estimates of 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 are 98% 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 natural gas 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 now makes 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. As in 2009, 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. 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 Torch NPI in 2010.

Our 2009 estimates of 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 are 99% natural gas and are sensitive to lower prices for natural gas and basis differentials in the Mid-Continent region. The natural gas price used to prepare our reserve report was $3.92 for NYMEX and $3.11 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. This low SEC-required price makes all of our proved undeveloped locations uneconomic in the Cherokee Basin. These locations are now 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 are 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 Torch NPI in 2009.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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 the 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.

The assumptions used to compute estimated future cash inflows do not necessarily reflect expectations of actual revenues or costs or their present value. 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, 2010	For the year ended December 31, 2009	For the year ended December 31, 2008
		(In 000's)	
Future cash inflows	$ 751,384	$ 522,145	$1,201,327
Future production costs	(404,350)	(277,881)	(500,184)
Future estimated development costs	(77,055)	(33,055)	(161,146)
Future net cash flows	269,979	211,209	539,997
10% annual discount for estimated timing of cash flows	(138,292)	(114,009)	(311,083)
Standardized measure of discounted estimated future net cash flows related to proved gas reserves	$ 131,687	$ 97,200	$ 228,914

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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, 2010	For the year Ended December 31, 2009	For the year Ended December 31, 2008
		(In 000's)	
Beginning of the period	$ 97,200	$ 228,914	$ 480,431
Sales and transfers of natural gas, net of production costs	(22,017)	(48,396)	(81,179)
Net changes in prices and production costs related to future production	9,480	(98,905)	(130,792)
Development costs incurred during the period	6,920	26,004	46,194
Changes in extensions and discoveries	424	1,022	9,502
Revisions of previous quantity estimates	45,556	(72,767)	(112,789)
Purchase of reserves in place	4,773	—	50,248
Accretion discount	9,720	22,891	48,043
Other	(20,369)	38,437	(80,744)
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 131,687	$ 97,200	$ 228,914

16. SUPPLEMENTAL QUARTERLY FINANCIAL DATA (Unaudited)

	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)

	2009 Quarters Ended			
	March 31,	June 30,	September 30,	December 31,
			(In 000's)	
Total revenue	$ 52,193	$ 18,564	$ 24,295	$ 47,484
Operating expenses	25,140	27,709	25,034	38,135
General and administrative expenses	5,233	4,208	4,568	4,497
Net income (loss)	$ 18,933	$ (16,744)	$ (9,101)	$ (2,111)
Earnings per unit—Basic	$ 0.85	$ (0.74)	$ (0.40)	$ (0.11)
Earnings per unit—Diluted	$ 0.85	$ (0.74)	$ (0.40)	$ (0.11)

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

17. SUBSEQUENT EVENTS

The following subsequent events have occurred between January 1, 2011, and February 25, 2011:

Members' Equity

2010 Equity

At February 25, 2011, we had 486,435 Class A units and 23,835,303 Class B units outstanding, which included 309,225 unvested restricted common units issued under our Long-Term Incentive Plan and 1,074,717 unvested restricted common units under our 2009 Omnibus Incentive Compensation Plan.

At February 25, 2011, 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.

At February 25, 2011, 125,615 common units have vested out of the 300,000 common units available under our Executive Inducement Bonus Program. This program has now terminated and the remaining 174,385 have been cancelled.

At February 25, 2011, we had granted 1,434,080 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 359,363 have vested.

During 2011, 64,862 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.2 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, 2010, which continues the temporary suspension we first announced in June 2009.

Litigation Related to Trust Termination

As previously disclosed, 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 relates to the non-operating net profits interest ("NPI") held by the Trust on certain wells owned by Robinson's Bend Production II, LLC ("RBP II"), a subsidiary of the company, in the Robinson's Bend Field in Alabama, and alleges, among other things, a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserting that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit seeks unspecified damages and an accounting of the NPI. The Alabama court has made the Trust a nominal party to the lawsuit. At a preliminary hearing on February 17, 2011, the Court approved a form of notice of a settlement among the parties to be sent by the Trust to its unitholders. A final hearing on the settlement is set for April 11, 2011. No assurance can be made that the Court will approve settlement or that the Trust will sell the NPI to RBP II. The settlement with Trust Venture, its successor and the Trust provides, among other things:

- RBP II will make a payment of $1.2 million to reimburse Trust Venture and its successor for their legal fees and expenses incurred in prosecuting the lawsuit;
- RBP II will make an irrevocable offer to purchase the NPI relating to the Robinson's Bend Field from the Trust for at least $1 million, when it is separately offered for sale by the Trust at public auction

within 180 days of the effective date of the settlement, with such bid amount to be deposited by RBP II in a third-party escrow account pending the public auction. RBP II, as well as any other bidders at the auction, shall have a right to submit a higher topping bid;

- The parties agree that the cumulative deficit balance in the NPI account is approximately $5.8 million as of September 30, 2010, and that no further payments will be due to the Trust with respect to the NPI unless and until the cumulative deficit balance is reduced to zero;
- Trust Venture and its successor agree, on behalf of the Trust, that all prior and current calculations, charges and deductions contained in such cumulative deficit NPI balance are in compliance with the terms of the Conveyance and, to the extent applicable thereunder, do not exceed competitive contract charges prevailing in the area for any such operations and services;
- The Water Gathering and Disposal Agreement between RBP II and another subsidiary of the Company will be amended to reduce the fee from $1.00 per barrel to $0.53 per barrel beginning on the first day of the month following the effective date of the settlement and to extend the term for an additional ten years, and Trust Venture and its successor agree, on behalf of the Trust, that the fees under such agreement do not exceed competitive contract charges prevailing in the area for the operations and services provided under such agreement during the extended term of such agreement;
- A mutual release among the parties and a dismissal with prejudice of the lawsuit; and
- An effective date of the settlement upon final approval by the Court.

Class D Interests

We have suspended all quarterly cash contributions with respect to our Class D interests. This suspension, approved by our board of managers, includes the $0.3 million quarterly cash distribution for the three months ended December 31, 2010 and $3.6 million which represents the distributions that were suspended for the quarterly periods ended September 30, June 30, and March, 31, 2010, and December 31, September 30, June 30, and March, 31, 2009, and December 31, September 30, June 30, and March 31, 2008. The remaining undistributed amount of the Class D interests is $6.7 million.

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SCHEDULE II

CONSTELLATION ENERGY PARTNERS LLC
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2010, 2009 and 2008
(In 000's)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2010					
Environmental reserves	$ 193	$ (193)	—	—	$ —
2009					
Environmental reserves	$ 441	$ (248)	—	—	$ 193
2008					
Environmental reserves	$ 546	$ (105)	—	—	$ 441

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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 25, 2011

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 and manager:		
By /S/ STEPHEN R. BRUNNER **Stephen R. Brunner**	Chief Executive Officer, Chief Operating Officer and President	February 25, 2011
Principal financial officer and treasurer:		
By /S/ CHARLES C. WARD **Charles C. Ward**	Chief Financial Officer and Treasurer	February 25, 2011
Principal accounting officer:		
By /S/ MICHAEL B. HINEY **Michael B. Hiney**	Chief Accounting Officer and Controller	February 25, 2011
Managers:		
/S/ STEPHEN R. BRUNNER **Stephen R. Brunner**	Manager	February 25, 2011
/S/ RICHARD H. BACHMANN **Richard H. Bachmann**	Manager	February 25, 2011
/S/ JOHN R. COLLINS **John R. Collins**	Manager	February 25, 2011
/S/ RICHARD S. LANGDON **Richard S. Langdon**	Manager	February 25, 2011
/S/ JOHN N. SEITZ **John N. Seitz**	Manager	February 25, 2011

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, 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, by and 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 ("Amendment No. 2").
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, between 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).
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 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).

Exhibit Number	Description
3.4	—Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated 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 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 the Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated 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	—Management Services Agreement, dated as of November 20, 2006, by and among Constellation Energy Partners LLC and Constellation Energy Partners Management, LLC (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
10.2	—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).
10.3	—Net Overriding Royalty Conveyance, dated as of November 22, 1993, but effective as of October 1, 1993, pursuant to Part I thereof, from Velasco Gas Company, Ltd. to Torch Energy Advisors Incorporated, and pursuant to Part II thereof, from Torch Energy Advisors Incorporated herein to the Torch Energy Royalty Trust (incorporated herein by reference to Exhibit 10.4 to Amendment No. 2).
10.4	—Oil and Gas Purchase Agreement, dated as of October 1, 1993, by and between Torch Energy Marketing, Inc., Torch Royalty Company and Velasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2).
10.5	—Letter agreement, dated as of June 13, 2005, by and between Robinson's Bend Marketing II, LLC and Torch Energy TM, Inc. (incorporated herein by reference to Exhibit 10.6 to Amendment No. 2).
10.6	—$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 thereto (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).
10.7	—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).
10.8	—Trademark License Agreement, dated as of November 20, 2006, by and between 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).

Exhibit Number	Description
10.9	—Water Gathering and Disposal Agreement, dated August 9, 1990, by and between Torch Energy Associates Ltd. and Velasco 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 October 1, 1993, by and between Torch Energy Associates Ltd. and Velasco 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 November 30, 2004, by and between Robinson's Bend Operating Company, LLC, successor in interest to Torch Energy Associates Ltd., and Everlast Energy LLC, successor in interest to Velasco Gas Company Ltd. (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	—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).
10.13	—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).
10.14	—Assignment, Assumption and Ratification Agreement, dated 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).
+10.15	—Letter Agreement, dated December 31, 2008, between Constellation Energy Partners LLC and Stephen R. Brunner (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on January 7, 2009, File No. 001-33147).
+10.16	—Letter Agreement, dated December 31, 2008, between Constellation Energy Partners LLC and Charles C. Ward (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on January 7, 2009, File No. 001-33147).
+10.17	—Letter Agreement, dated December 31, 2008, between Constellation Energy Partners LLC and Lisa J. Mellencamp (incorporated herein by reference to Exhibit 10.22 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
+10.18	—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).
+10.19	—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).
+10.20	—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).

Exhibit Number	Description
+10.21	—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).
+10.22	—Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Stephen R. Brunner (incorporated herein by reference to Exhibit 10.5 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
+10.23	—Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Charles C. Ward (incorporated herein by reference to Exhibit 10.6 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
+10.24	—Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Lisa J. Mellencamp (incorporated herein by reference to Exhibit 10.7 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
+10.25	—Inducement Award Agreement, dated May 1, 2009, by and between Constellation Energy Partners LLC and Michael B. Hiney (incorporated herein by reference to Exhibit 10.8 to the Current Report on Form 8-K/A filed by Constellation Energy Partners LLC on May 5, 2009, File No. 001-33147).
+10.26	—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).
+10.27	—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).
+10.28	—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).
+10.29	—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).
+10.30	—Form of Grant Agreement Relating to Restricted Units—Independent Managers (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 March 3, 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.

Exhibit Number	Description
*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.

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

EXHIBIT 12.1

RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth the ratios of earnings to fixed charges for us and our predecessors for each of the periods indicated. All dollar amounts are reported in thousands.

	2010	2009	2008	2007	2006
Net Income (loss)(1)	$(276,810)	$ (8,645)	$ 7,418	$14,447	$15,989
Fixed Charges:					
Total Fixed Charges(2)	13,096	12,127	12,256	6,930	221
Total	13,096	12,127	12,256	6,930	221
Earnings (loss)	$(263,714)	$ 3,482	$19,674	$21,377	$16,210
Ratio of earnings (loss) to fixed charges(3)	—	—	1.61x	3.08x	73.35x

(1) Net income is the equivalent of income from continuing operations, as CEP has no discontinued operations, minus income from equity affiliates that exceeded dividends from affiliates.

(2) Fixed charges equal the sum of the following: interest expensed and capitalized; amortized premiums, discounts, and capitalized expenses related to indebtedness; and a reasonable approximation of the interest within rent expense.

(3) Earnings were inadequate to cover fixed charges in certain periods. The coverage deficiency totaled approximately $277.0 million for the fiscal year ended December 31, 2010 and $8.7 million for the fiscal year ended December 31, 2009.

EXHIBIT 21.1

Subsidiaries of
Constellation Energy Partners LLC

	Jurisdiction of Organization
CEP Mid-Continent LLC	Delaware
CEP Services Company, Inc.	Delaware
Northeast Shelf Energy, L.L.C.	Oklahoma
Mid-Continent Oilfield Supply, L.L.C.	Oklahoma
Robinson's Bend Operating II, LLC	Delaware
Robinson's Bend Production II, LLC	Delaware

* The names of certain indirectly owned subsidiaries have been omitted because, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary pursuant to Rule 1-02(W) of Regulation S-X.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-140745, 333-158944 and 333-163426) and on Form S-3 (Nos. 333-147085 and 333-171792) of Constellation Energy Partners LLC of our report dated February 25, 2011 relating to the financial statements and financial statement schedule which appear in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Houston, Texas
February 25, 2011

Exhibit 23.2

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers, we hereby consent to the references to us and to estimates of reserves contained in this Annual Report on Form 10-K of Constellation Energy Partners LLC for the year ended December 31, 2010 and in Constellation Energy Partners LLC's previously filed Registration Statements on Form S-8 (Nos. 333-140745, 333-158944 and 333-163426) and on Form S-3 (Nos. 333-147085 and 333-171792).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /S/ DANNY D. SIMMONS

Danny D. Simmons, P.E.
Executive Vice President

Houston, Texas
February 25, 2011

EXHIBIT 31.1

CONSTELLATION ENERGY PARTNERS LLC

CERTIFICATION

I, Stephen R. Brunner, certify that:

1. I have reviewed this Annual Report on Form 10-K of Constellation Energy Partners LLC;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: February 25, 2011

/S/ STEPHEN R. BRUNNER

Stephen R. Brunner
Chief Executive Officer, Chief Operating Officer and President

CONSTELLATION ENERGY PARTNERS LLC

CERTIFICATION

I, Charles C. Ward, certify that:

1. I have reviewed this Annual Report on Form 10-K of Constellation Energy Partners LLC;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: February 25, 2011

/s/ CHARLES C. WARD

Charles C. Ward
Chief Financial Officer and Treasurer

EXHIBIT 32.1

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

I, Stephen R. Brunner, Chief Executive Officer, Chief Operating Officer and President of Constellation Energy Partners LLC, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2010 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Partners LLC.

/S/ STEPHEN R. BRUNNER

Stephen R. Brunner
Chief Executive Officer, Chief Operating Officer and President

Date: February 25, 2011

EXHIBIT 32.2

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

I, Charles C. Ward, Chief Financial Officer and Treasurer of Constellation Energy Partners LLC, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2010 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Partners LLC.

/S/ CHARLES C. WARD

Charles C. Ward
Chief Financial Officer and Treasurer

Date: February 25, 2011

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

February 14, 2011

Mr. Richard A. Miller
Constellation Energy Partners LLC
1801 Main Street, Suite 1300
Houston, Texas 77002

Dear Mr. Miller:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2010, to the Constellation Energy Partners LLC (Constellation) interest in certain oil and gas properties located in Alabama, Kansas, Nebraska, and Oklahoma. We completed our evaluation on February 14, 2011. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Constellation. The estimates in this report have been prepared in accordance with the definitions and guidelines of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Constellation's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Constellation interest in these properties, as of December 31, 2010, to be:

	Net Reserves		Future Net Revenue ($)	
Category	**Oil (Barrels)**	**Gas (MCF)**	**Total**	**Present Worth at 10%**
Proved Developed Producing	443,284	103,074,289	219,822,400	121,932,500
Proved Developed Non-Producing	12,861	21,815,955	21,228,600	10,368,800
Proved Undeveloped[1]	48,493	41,089,305	28,927,700	(614,800)
Total Proved	504,638	165,979,547	269,978,800	131,686,400

Totals may not add because of rounding.

(1) Estimates of proved undeveloped reserves have been included for certain locations that generate positive future net revenue but have negative present worth discounted at 10 percent based on the constant prices and costs discussed in subsequent paragraphs of this letter.

The oil reserves shown include crude oil and condensate. Oil volumes are expressed in barrels that are equivalent to 42 United States gallons. Gas volumes are expressed in thousands of cubic feet (MCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. Estimates of proved undeveloped reserves have been included for certain locations that generate positive future net revenue but have negative present worth discounted at 10 percent based on the constant prices and costs discussed in subsequent paragraphs of this letter. These locations have been included based on the operators' declared intent to drill these wells, as evidenced by Constellation's internal budget, reserves estimates, and price forecast. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves

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nsai@nsai-petro.com
netherlandsewell.com

subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Future gross revenue to the Constellation interest is prior to deducting state production taxes and ad valorem taxes. Future net revenue is after deductions for these taxes, future capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Also, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2010. For oil volumes, the average regional posted or spot prices are adjusted by lease for quality, transportation fees, and local price differentials. For gas volumes, the average regional spot prices are adjusted by property group for energy content, transportation fees, and local price differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $75.57 per barrel of oil and $4.250 per MCF of gas. Average index prices along with the average realized prices for each property group are shown in the following table:

	Oil			Gas		
Property Group	**Pricing Index**	**Average Posted/Spot Price ($/Barrel)**	**Average Realized Price ($/Barrel)**	**Pricing Index**	**Average Spot Price ($/MMBTU)**	**Average Realized Price ($/MCF)**
Cherokee Basin	West Texas Intermediate	75.96	76.79	Oneok Oklahoma	4.144	3.983
CEP Cola	N/A	—	—	CenterPoint East	4.162	4.224
Robinson’s Bend	N/A	—	—	Southern Natural Louisiana	4.367	4.554
St. Anselm	West Texas Intermediate (Cushing)	79.43	72.21	N/A	—	—

Lease and well operating costs used in this report are based on operating expense records of Constellation. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Headquarters general and administrative overhead expenses of Constellation are included to the extent that they are covered under joint operating agreements for the operated properties. Lease and well operating costs are held constant throughout the lives of the properties. Capital costs are included as required for workovers, new development wells, and production equipment. The future capital costs are held constant to the date of expenditure.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the Constellation interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Constellation receiving its net revenue interest share of estimated future gross gas production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of Constellation to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and guidelines. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Constellation, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-002699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E. 102425
Vice President

Date Signed: February 14, 2011

By: /s/ David E. Nice
David E. Nice, P.G. 346
Vice President

Date Signed: February 14, 2011

RBT:EBL