Constellation Energy Partners LLC
Form 10-K
March 27, 2014

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, 2013

OR

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

For the transition period from   to   .

Commission File Number 001-33147

Constellation Energy Partners LLC

(Exact Name of Registrant as Specified in Its Charter)

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

Telephone Number: (832) 308-3700

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

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

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

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

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 (Do not check if a smaller reporting company)	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 Units, without par value, held by non-affiliates as of June 28, 2013 was approximately $33,467,455 based upon NYSE MKT LLC 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 March 21, 2014: 28,399,502 common units.

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PART I

Item 1. Business

Overview

We are a limited liability company formed in 2005. We are focused on the acquisition, development and production of oil and natural gas properties, as well as midstream assets. Our proved reserves are located in the Cherokee Basin in Oklahoma, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas and in Texas and Louisiana. Our primary business objective is to create long-term value and to generate stable cash flows allowing us to invest in our business to grow our reserves and production. We operate our oil and natural gas properties as one business segment: the exploration, development and production of oil and natural gas.

We completed our initial public offering on November 20, 2006 and our Class B common units are listed on the NYSE MKT LLC (NYSE MKT) 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," or the "Company" means Constellation Energy Partners LLC and its subsidiaries. Referer in this Annual Report on Form 10-K to "PostRock" and "CEPM" are to PostRock Energy Corporation (NASDAQ: PSTR) and its subsidiary, Constellation Energy Partners Management, LLC, respectively. References in this Annual Report on Form 10-K to "Exelon" and "CEPH" are to Exelon Corporation (NYSE: EXC) and its subsidiary, Constellation Energy Partners Holdings, LLC, respectively. References in this Annual Report on Form 10-K to "SOG" and "SEP I" are to Sanchez Oil & Gas Corporation and its affiliate, Sanchez Energy Partners I, LP, respectively. References in this Annual Report on Form 10-K to "Constellation" are to Constellation Energy Group, Inc.

Business Strategy

Our primary business objective is to create long-term value and to generate stable cash flows allowing us to invest in our business to grow our reserves and production. We plan to achieve our objective by executing our business strategy, which is to:

- organically grow our business by increasing reserves and production through what we believe to be low-risk development drilling that focuses on capital efficient production growth and oil opportunities on our existing properties in the Mid-Continent region and in Texas and Louisiana;

- reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient hedging programs; and

- make accretive, right-sized acquisitions of oil and natural gas properties characterized by a high percentage of proved developed oil and natural gas reserves with long-lived, stable production and low-risk drilling opportunities.

Since 2009, our primary focus has been to reduce our outstanding debt while maintaining a limited capital expenditure program to expand our oil production and reserves. As part of this focus, during 2013, we sold our Robinson's Bend Field assets in the Black Warrior Basin of Alabama and used a portion of the proceeds from that sale to reduce our outstanding debt. As a result of this sale, amounts related to the Robinson's Bend Field assets have been reported as discontinued operations in 2013 and 2012. All prior year information relating to the Robinson's Bend Field assets has been restated as discontinued operations, and all information reported or discussed in this Annual Report on Form 10-K reflects the treatment of the Robinson's Bend Field assets as discontinued operations. We also amended our reserve-based credit facility to extend its maturity to May 2017 and expand our borrowing capacity, and we acquired producing oil and natural gas assets in Texas and Louisiana from SEP I. These actions, along with work completed prior to 2013, have allowed us to reduce our outstanding debt from a high of $220.0 million in 2009 to $50.7 million at December 31, 2013. During 2013, we also increased our oil production by 84.0% and increased our proved oil reserves to approximately 2.1 million barrels. We intend to continue our business strategy to expand our oil production and reserves while actively pursuing opportunities, including merger and acquisitions, which could lead to enhanced unitholder value.

Oil and Natural Gas Properties

Our total estimated proved reserves at December 31, 2013, were approximately 91.3 Bcfe, approximately 86% of which were classified as proved developed, and 85% of which were natural gas and 15% of which were oil. At December 31, 2013, we owned approximately 1,995 net producing wells. Our total average proved reserve-to-production ratio is approximately 9.9 years and our portfolio decline rate is 13% to 15% based on our estimated proved reserves at December 31, 2013 and production for the month ended December 31, 2013.

Below is a description of our operations and our oil and natural gas properties by basin at December 31, 2013:

Cherokee Basin

The Cherokee Basin is located in the Mid-Continent region in southern Kansas, northern Oklahoma and western Missouri, and covers approximately 26,000 square miles. The predominant production is natural gas produced from coals and shales, and natural gas and oil from conventional formations. In 2007, we invested in the Cherokee Basin, pursuing a coalbed methane resource play targeting Pennsylvanian coals. As coalbed methane wells were drilled, oil zones were also found and, when economical, developed. Our investment focus is currently targeting oil development by exploiting Cherokee Basin oil opportunities previously uneconomical due to commodity price levels. Natural gas discovered with oil continues to be a value add, and is handled by our extensive existing natural gas and water gathering infrastructure.

Our production is primarily from the Pennsylvanian coals, shales and sands. Major zones are the Mulky Iron Post Shale, Weir Pitt Coal, and Skinner, Red Fork, and Bartlesville sands. Deeper Mississippian, Woodford (Devonian) and Arbuckle (Ordovician) formations are potentially productive; but currently minimal to our reserve values. The eastward movement of the Mid-Continent horizontal Mississippian drilling into Osage County continues to offer future value to our ownership position in the area if commercial success can be demonstrated.

Average Cherokee Basin well depth is approximately 2,000 feet in the western portion of the Basin (Osage County, Oklahoma) and approximately 1,000 feet in the eastern portion (Nowata County, Oklahoma). Similarly to depth, average well costs are approximately $340,000 in the west and approximately $170,000 in the east. Offsetting our lower drilling costs are the relatively low reserves and low daily production rates per well. Typical coalbed methane wells produce over a period of 20 to over 50 years, and on average have less favorable economic characteristics than conventional natural gas wells. A typical oil completion in these areas declines over one to two years and then produces at a steady rate similar to a coalbed methane well.

At December 31, 2013, we owned approximately 1,948 net producing wells in the Cherokee Basin. The natural gas coming from our wells is low pressure due to the shallow producing formations and compression is needed to move the natural 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; Enable Oklahoma Intrastate Transmission, LLC; and Southern Star Central Gas Pipeline, Inc. We operate a substantial portion of our production in the Cherokee Basin. We also own a 50% working interest in most wells operated by Bullseye Operating, L.L.C. (Bullseye) and a 50% interest in Bullseye itself. Bullseye operates approximately 500 gross wells in Washington and Nowata Counties in Oklahoma and sells its production through the Cotton Valley producers cooperative, Cotton Valley Compression, L.L.C. Our average gross working interest in our Cherokee Basin properties is approximately 80%, with our average gross working interest in our operated properties being approximately 100% and our average gross working interest in our non-operated Cherokee Basin properties being approximately 50%.

Our estimated proved reserves in the Cherokee Basin at December 31, 2013 were approximately 79.6 Bcfe, approximately 84% of which were classified as proved developed, with 87% being natural gas and 13% being oil.

Woodford Shale

The Woodford Shale is located in the Arkoma Basin in southern Oklahoma. We own 82 well bores, or approximately nine 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 fractures required. The gas-bearing shale section ranges from 120 to 200 feet thick. As of December 31, 2013, our 82 wells had an average gross working interest of 11.3% and an average net revenue interest of 9.1%. Approximately 90% of the wells are operated by affiliates of Devon Energy Corporation (Devon) and Newfield Exploration Mid-Continent, Inc. (Newfield), with the remaining wells operated by three additional companies. We do not have any additional drilling or leasehold rights associated with our Woodford Shale properties and expect declining production rates and limited future capital expenditures for these wells.

Our estimated proved reserves in the Woodford Shale at December 31, 2013 were approximately 3.7 Bcfe, all of which were classified as proved developed and all 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, 2013, we had a gross acreage position of 3,710 acres, or approximately 893 net acres, and we owned 26 gross wells, or approximately 5 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 to 4,900 feet depending on targets and location. Wells in this region typically cost approximately $450,000 to drill and complete.

Murfin Drilling Company, Inc., an experienced oil producer in Kansas, operates all of our wells in this region. The average gross working interest in the wells is approximately 20% and the average net revenue interest is approximately 16%.

Our estimated proved reserves in the Central Kansas Uplift at December 31, 2013 were approximately 0.3 Bcfe, approximately 100% of which were classified as proved developed and 95% were oil.

Black Warrior Basin

All of the natural gas properties that we owned in the Black Warrior Basin at December 31, 2012, were sold to a third party on February 28, 2013, and a majority of the sales proceeds were used to reduce our outstanding debt level. These properties have been classified as discontinued operations in our consolidated financial statements.

Onshore Texas and Louisiana Gulf Coast

In August 2013, we acquired oil, natural gas and natural gas liquids assets in the onshore Texas and Louisiana Gulf Coast Region. The acquired assets include 67 producing wells, none of which are operated by us. SOG operates assets located across the southern edge of the Texas coastline. Zachry Exploration, LLC (Zachry) operates assets located in onshore southern Louisiana. Drilled depths range from 9,000 to 12,000 feet mainly targeting the Miocene-Eocene-Paleocene Series sands and cost approximately $1.5 million to $2.0 million to drill and complete. The wells produce a combination of oil, natural gas and natural gas liquids and are typically vertical well bores. At December 31, 2013, there were 67 gross wells, 32 net working interest wells, producing a total of 1,167 barrels of oil equivalent per day. Approximately 75% of the wells are operated by SOG. Since acquisition in August 2013, we have participated in one new SOG operated well and one new Zachry operated well, along with a few recompletions and workovers.

Our estimated proved reserves in Texas and Louisiana at December 31, 2013 were approximately 7.6 Bcfe, approximately 100% of which were classified as proved developed, with 61% being natural gas, 28% being oil and 11% being natural gas liquid.

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:	2013	2012
Estimated proved reserves:		
Oil (MMBbl)	2.2	1.1
Natural gas (Bcf)	78.0	37.1
Total proved reserves (Bcfe)	91.3	43.6
Estimated proved developed reserves:		
Oil (MMBbl)	2.0	0.9
Natural gas (Bcf)	66.6	35.5
Total proved reserves (Bcfe)	78.7	40.9
Estimated proved undeveloped reserves:		
Oil (MMBbl)	0.2	0.2
Natural gas (Bcf)	11.4	1.6
Total proved reserves (Bcfe)	12.6	2.7
Proved developed reserves as a percent of total reserves	86%	94%
Standardized Measure (in millions)	$ 143.7	$ 60.5

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

(b)In February 2013, we sold all of our Black Warrior Basin properties, which are not included in the table.

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

At December 31, 2013 and 2012, 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 petro physicists exceeds 20 years, including 5 to 15 years with a major oil company. We maintain an internal technical staff of engineers and geosciences 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 natural 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 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. We do not rely on any proprietary technology to drill our development wells. Based on our structure as a limited liability company and our current business plans, our forecasted cash flow over the next five years is expected to be sufficient to fund this type of development drilling program on certain of our proved undeveloped locations. Using the SEC rules for estimating proved reserves, we only recorded proved undeveloped locations that are scheduled to be drilled within the next five years. Any locations that are identified to be drilled beyond five years are classified as probable or possible reserves. We record our proved undeveloped locations typically at one offset location, but we can also record proved undeveloped locations on one section surrounding existing production subject to available infrastructure. We have the right to develop locations under our concession agreement with the Osage Nation in Osage County, Oklahoma, subject to its terms and conditions, until 2020 and we have leasehold availability for our other proved undeveloped locations. During 2014, we currently expect our $20.0 million to $22.0 million capital budget to support a level of drilling activity that we anticipate to be sufficient to develop our 2014 inventory of proved undeveloped locations.

The following table summarizes our inventory of proved undeveloped locations as of December 31, 2013, including those we purchased from SEP I on August 9, 2013:

	Year PUD Is Scheduled To Be Developed				
	2014	2015	2016	2017	2018

Number of Locations	61	49	47	32	—
Equivalents-Bcfe	3.7	2.8	4.0	2.2	—
Capital Estimate-$millions	$ 8.7	$ 5.0	$ 4.1	$2.0	$—

Our 2013 estimates of total proved reserves increased 47.7 Bcfe from 2012 due to a higher SEC-required price for natural gas used to calculate our reserves in 2013 and the addition of Texas and Louisiana properties. Our reserve revisions of 44.7 Bcfe are primarily the result of higher natural gas prices. We added 4.8 Bcfe from extensions and discoveries in the Cherokee Basin reserves associated with oil opportunities. 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 prices for Enable Gas Transmission, LLC (East), Natural Gas Pipeline Co. of America (Midcontinent), ONEOK

Gas Transportation LLC (Oklahoma), Panhandle Eastern Pipe Line Co. (Texas, Oklahoma) and Southern Star Central Gas Pipeline Inc. (Texas, Oklahoma, Kansas) with respect to our properties in the Cherokee Basin; the Inside FERC price for Enable Gas Transmission, LLC (East) with respect to our properties in the Woodford Shale; the Inside FERC price for Southern Natural Gas Co. (Louisiana) (SONAT Inside FERC price) with respect to the properties we previously owned in the Black Warrior Basin; the Inside FERC price for Tennessee Gas Pipeline Co. (Texas, zone 0), Texas Eastern Transmission Corp. (South Texas zone) and Houston Ship Channel market center with respect to our properties along the Gulf Coast and the applicable monthly average posted oil price with respect to our properties in the Central Kansas Uplift, the Cherokee Basin and the Gulf Coast. The following table summarizes year-end closing prices for the major indexes applicable to our business:

	Prices on January 1,		
Market Prices:	2014	2013	2012
Natural gas price—NYMEX (Henry Hub)	$ 4.41	$ 3.35	$ 3.08
Natural gas price—Enable Gas Transmission, LLC (East)(a)	$ 4.30	$ 3.24	$ 2.97
Natural gas price—Natural Gas Pipeline Co. of America (Midcontinent)	$ 4.37	$ 3.26	$ 3.01
Natural gas price—Houston Ship Channel	$ 4.31	$ 3.32	$ 3.04
Natural gas price—ONEOK Gas Transportation LLC (Oklahoma)	$ 4.31	$ 3.24	$ 3.04
Natural gas price—Panhandle Eastern Pipe Line Co. (Texas, Oklahoma)	$ 4.27	$ 3.23	$ 2.99
Natural gas price—Southern Natural Gas Co. (Louisiana)	$ 4.37	$ 3.40	$ 3.09
Natural gas price—Southern Star Central Gas Pipeline Inc. (Texas, Oklahoma, Kansas)	$ 4.28	$ 3.20	$ 3.02
Natural gas price—Tennessee Gas Pipeline Co. (Texas, zone 0)	$ 4.26	$ 3.28	$ 3.03
Natural gas price—Texas Eastern Transmission Corp. (South Texas zone)	$ 4.29	$ 3.27	$ 2.95
Oil price—West Texas Intermediate—Cushing	$ 98.17	$ 91.83	$ 98.83

(a) Previously called CenterPoint Energy Gas Transmission Co. (East)

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

Production and Price History

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

	For the Year Ended December 31, 2013	2012
Net Production:		
Natural gas production (MMcf)	6,862	7,482
Oil and liquids production (MBbl)	221	121
Total production (Mmcfe)	8,188	8,205
Average daily production (Mcfe/d)	22,433	22,418
Average Sales Prices:		
Natural gas price per Mcf with hedge settlements	$ 5.78	$ 5.69
Natural gas price per Mcf without hedge settlements	$ 3.51	$ 2.53
Oil and liquids price per Bbl with hedge settlements	$ 98.18	$ 105.22
Oil and liquids price per Bbl without hedge settlements	$ 97.07	$ 98.97
Total price per Mcfe with hedge settlements	$ 7.49	$ 6.73
Total price per Mcfe without hedge settlements	$ 5.56	$ 3.76
Average Unit Costs Per Mcfe:		
Field operating expenses	$ 2.62	$ 2.57
Lease operating expenses	$ 2.30	$ 2.37
Production taxes	$ 0.32	$ 0.20
General and administrative expenses	$ 2.57	$ 1.92
Depreciation, depletion and amortization	$ 2.32	$ 1.43
Asset impairments	$ 0.29	$ 0.01

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

(b)In February 2013, we sold all of our Black Warrior Basin properties, which are not included in the table.

Productive Wells

The following table sets forth information at December 31, 2013, relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of producing commercial quantities of oil or natural gas, including oil and natural gas wells awaiting pipeline connections to commence deliveries. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Natural Gas		Oil	
	Gross	Net	Gross	Net
Operated	1,586	1,537	224	217
Non-operated	519	224	54	17
Total	2,105	1,761	278	234

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, 2013 and 2012, respectively. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that are capable of producing commercial quantities of oil or natural gas, regardless of whether they produce a reasonable rate of return. No exploratory wells were drilled on any of our properties during the years ended December 31, 2013 or 2012, respectively.

	Year Ended December 31, 2013	2012	Wells in Progress at December 31, 2013
Gross:			
Development	64	50	2
Productive	-	-	-
Dry	15	50	4
Recompletions	79	100	6
Total			
Net:			
Development			
Productive	64	50	2
Dry	-	-	-
Recompletions	15	50	4
Total	79	100	6

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2013 related to our leasehold acreage.

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross(c)	Net(d)	Gross(c)	Net(d)
Total	237,226	216,368	28,381	19,795

(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.

Leases

Our leases are concentrated in Oklahoma (82%), Texas (9%), Kansas (7%) and Louisiana (2%). We have approximately 1,623 leases in the Cherokee Basin on approximately 224,017 net acres. Our acreage includes areas leased under a concession agreement that we have with the Osage Nation in Osage County, Oklahoma, which provides us with the exclusive right to lease for coalbed methane on up to 560,000 acres within Osage County and the exclusive right for a period of 90 days after drilling a coalbed methane well on any such acreage to lease for oil and natural gas on such acreage. Generally, we have the right each year to elect to license up to a certain amount of acreage under the concession agreement for such year for a specified license payment, and a license must be obtained before we then lease the acreage. During the term of the concession agreement, however, we have the exclusive right to lease the acreage covered there under for coalbed methane unless we notify the Osage Nation in writing that we have no intention to lease any particular acreage. Our concession agreement with the Osage Nation is in four phases: (i) Phase I (four year term of January 1, 2005 through December 31, 2008) during which not less than 440 production wells were to have been drilled and completed; (ii) Phase II (four year term of January 1, 2009 through December 31, 2012) during which a cumulative of not less than 680 production wells were to have been drilled and completed; (iii) Phase III (four year term of January 1, 2013 through December 31, 2016) during which a cumulative of not less than 920 production wells shall be drilled and completed; and (iv) Phase IV (four year term of January 1, 2017 through December 21, 2020) during which a cumulative of not less than 1,160 production wells shall be drilled and completed, such that not less than a total of 1,160 production wells shall be drilled in Phases I through IV. Generally, in addition to the drilling and completion of a producing well counting as a “production well,” the drilling of two dry holes are counted as one “production well,” a recompletion of an existing wellbore is counted as one “production well,” a horizontal well is counted as two “production wells” and a salt water disposal well is counted as one “production well” under the concession agreement (hereinafter “production well credits”). As of December 31, 2013, we believe we have earned approximately 788 total production well credits and our total developed and undeveloped leased acreage totaled approximately 64,480 acres. This level of credits was sufficient to achieve the specific drilling targets under the concession agreement through Phase II, which ended December 31, 2012. If the drilling requirement for a particular phase is not met, we have the option to make a payment equal to the shortfall of production wells required to be drilled multiplied by $50,000 per well in order to be deemed to have complied with the requirement for that phase. If the drilling requirement of a particular phase were not met (either through drilling of production wells or payment as described above), the Osage Nation's sole remedy would be the termination of the concession agreement at the expiration of the then current phase, provided that such termination would have no effect upon our wells already drilled and the leases that we have acquired that are producing in paying quantities. We believe the Osage Nation has granted at least two concessions for the drilling of conventional oil and natural gas on acreage which overlaps certain of the acreage covered by our earlier granted concession and it has taken the position that we are not entitled to conventional oil and natural gas leases under the terms of our concession agreement where we have not drilled a coalbed methane well first.

The typical oil and natural 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 an 80% net revenue interest to us, and on our non-operated properties is generally a 40% net revenue interest. We have 58 leases with a gross acreage position of 3,710 acres in the Central Kansas Uplift, or approximately 893 net acres. We have no leasehold rights associated with our 82 well bores in the Woodford Shale. We have approximately 124 leases in Louisiana with a gross acreage position of 3,427 acres, or approximately 679 net acres. We have approximately 584 leases in Texas with a gross acreage position of 23,143 acres, or 10,574 net acres.

Under the oil and natural 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 7%, 8% and 9% of our total net undeveloped acreage of 19,795 acres is held under leases that have remaining primary terms expiring in 2014, 2015 and 2016, respectively. Of these expiration amounts in 2014, 2015, and 2016, approximately 79%, 96%, and 84%, respectively, apply to our concession agreement with the Osage Nation. If these leases do expire, we have the exclusive right to acquire a new coalbed methane lease on any expired acreage under our concession agreement with the Osage Nation until its expiration in 2020 or any earlier termination according to its terms and conditions. The remaining expiring acreage in all three years is primarily located in Kansas and Oklahoma.

Operations

General

We were the operator of approximately 88% of the 1,995 net wells in which we owned an interest at December 31, 2013. 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 holders of our Class A units. We have the responsibility for the overall operations of our fields and developing our drilling programs and other production enhancement opportunities. Field operations and the related technical support services, including geology, engineering, land administration and accounting, are conducted by employees of one of our subsidiaries. Our employees and contractors approve the design and the development, maintenance, recompletion and workover for all of the wells in our fields. Our drilling programs are designed by us and implemented by various contractors. We do not own drilling rigs or other oil field service equipment used for drilling wells on our properties.

Field Operations

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

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

For our 82 well bores located in the Woodford Shale, the operators of the properties—primarily Devon and Newfield—conduct all operations on our behalf. For our 26 non-operated wells located in the Central Kansas Uplift, Murfin Drilling Company Inc., the operator, conducts all operations on our behalf. For our 51 non-operated wells located in Texas, SOG is the operator and conducts all operations on our behalf. For our 16 non-operated wells located in Louisiana, Zachry is the operator and conducts all operations on our behalf.

Geology and Engineering

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

Land Administration

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

Revenue Accounting

Through December 31, 2012, our revenue accounting function for all of our properties was 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 natural gas industry. Schlumberger managed the cash flow associated with our interests in the oil and natural gas properties, including the payment of invoices, calculation and payment of royalties, and receipt of revenues from oil and natural gas sales, and provided accounting information used to generate financial statements. Beginning in January 2013, these functions are handled by our internal accounting department in Houston, Texas.

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 Cherokee Basin to Macquarie Energy LLC; Keystone Gas Corporation; Scissortail Energy, LLC; Cotton Valley Compression, L.L.C.; Cherokee Basin Pipeline, LLC and ONEOK Energy Services Company, L.P. Our oil production in the Cherokee Basin is primarily purchased by Sunoco Partners Marketing and Terminals L.P. and Coffeyville Resources Refining and Marketing, LLC. Our natural gas production in the Woodford Shale and our oil production in the Central Kansas Uplift is marketed by the operators of our properties. Our natural gas and oil production in the onshore Texas and Louisiana Gulf Coast region is marketed by the operators of our properties.

Hedging and Risk Management Activities

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

Markets and Competition

We operate in a competitive environment for acquiring properties, marketing oil and natural gas and retaining trained personnel. Many of our competitors have substantially greater financial, technical and personnel resources than ours. As a result, our competitors may be able to outbid us for oil and natural gas properties and exploratory prospects, more competitively price their production, or utilize superior technical resources than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a competitive environment with limited access to capital. There is substantial competition for the limited capital available for investment in the oil and natural gas industry. None of PostRock, Exelon, SOG or any of their affiliates are restricted from competing with us.

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

Title to Properties

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

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

Environmental Matters and Regulation

General

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

•require the acquisition of various permits before drilling commences;

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

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

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

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible in the absence of such regulations. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, federal, state, local and Native American tribal authorities frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

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

Waste Handling

The Resource Conservation and Recovery Act (RCRA), and comparable state laws, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency (EPA), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most other wastes associated with the exploration, development and production of oil and natural gas are currently regulated under RCRA’s non-hazardous waste provisions. 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, could increase our costs to manage and dispose of wastes.

Comprehensive Environmental Response, Compensation and Liability Act

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

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

Water Discharges

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

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

Air Emissions

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

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

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

Hydraulic Fracturing

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

OSHA and Other Laws and Regulation

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

Our operations in the 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. 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, 2013, we had no accrued environmental obligations. We are not aware of any environmental issues or claims that will require material capital expenditures or that will otherwise have a material impact on our financial position or results of operations. However, we cannot predict how future environmental laws and regulations may impact our operations, and therefore cannot provide assurance that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial condition, results of operations or cash flows.

Employees

As of December 31, 2013, our subsidiary, CEP Services Company, Inc., had 79 employees. None of these employees are subject to a collective bargaining agreement.

Offices

We are headquartered in Houston, Texas. We also maintain field offices in Coffeyville, Kansas and Skiatook, Oklahoma. We own the field office buildings and land in Kansas and Oklahoma.

Available Information

Our internet address is http://www.constellationenergypartners.com. We make our website content available for informational purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Annual Report on Form 10-K. We make available free of charge on or through our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC maintains an internet website that contains these reports at http://www.sec.gov. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information concerning the operation of the Public Reference Room may be obtained by calling the SEC at (800) 723-0330.

Item 1A. Risk Factors

Risks Related to Our Business

Drilling for and producing oil and natural gas are costly and high-risk activities with many uncertainties that could adversely affect our business, financial condition, results of operation, operating cash flow and any 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;
" adverse weather conditions;
" facility or equipment malfunctions;
" title problems;
" piping, casing or cement failures;
" compliance with environmental and other governmental requirements;
" unusual or unexpected geological formations;
" loss or damage to oilfield drilling and service tools;
" loss of drilling fluid circulation;
" formations with abnormal pressures;
" environmental hazards, such as gas leaks, oil spills, compressor incidents, pipeline ruptures and discharges of toxic gases;
" water pollution;
" fires;
" accidents or natural disasters;
" blowouts, craterings and explosions;
" uncontrollable flows of oil, natural gas or well fluids; and
" loss or theft of data due to cyber attacks.

Any of these events can cause increased costs or restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling program or significant increase in costs could impact our ability to generate sufficient cash flow to operate our business. Increased costs could include losses from personal injury or loss of life; damage to or destruction or loss of property, natural resources, equipment, and data; pollution; environmental contamination; loss of wells and regulatory penalties.

We ordinarily maintain insurance against certain 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. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on 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 affect on our financial condition, results of operations and ability to pay distributions.

Our inability to replace our reserves could result in a material decline in our reserves and production. Unless we replace the reserves that we produce, our existing reserves will decline, which could adversely affect our production and adversely affect our cash from operations and our ability to pay distributions to our unitholders.

Producing oil and natural gas reservoirs are characterized by declining production rates that vary based on the reservoir characteristics and other factors. The rate of decline of our reserves and production included in our reserve report at December 31, 2013 will change if production from our existing wells declines in a different manner than we have estimated and may 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. 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 could adversely affect our business, financial condition, results of operations and ability to pay distributions to our unitholders.

We are unlikely to be able to make distributions without making accretive acquisitions or capital expenditures that maintain or grow our asset base. If we do not make sufficient growth capital expenditures, we will be unable to sustain and expand our business operations and therefore will be unable to pay distributions to our unitholders.

Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

It is not possible to 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. Our independent reserve engineers do not independently verify the accuracy and completeness of information and data furnished by us. In estimating our level of oil and natural gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

•future oil and natural gas prices;

" production levels;
" capital expenditures;
" operating and development costs;
" the effects of regulation;
" the accuracy and reliability of the underlying engineering and geologic data; and
" the availability of funds.

If these assumptions prove to be incorrect, 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 or recovery and our estimates of the future net cash flows from our reserves could change significantly.

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). Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual drilling and production.

The reserve estimates we make for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracies in our estimates of proved reserves, future production rates and the timing of development expenditures.

The present value of future net cash flows from our estimated 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 estimated proved reserves on prices and costs in effect on the day of the estimate. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

•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 actual production;

•the amount and timing of our capital expenditures;

•supply of and demand for oil and natural gas; 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 in compliance with the FASB Accounting Standards 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 could 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.

Future price declines or downward reserve revisions may result in additional write-downs of our asset carrying values, which could adversely affect our results of operations and limit our ability to borrow funds.

Declines in oil and natural gas prices may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write-down, as a noncash charge to earnings, the carrying value of our properties for impairments. We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. We are required to perform impairment tests on our assets periodically and whenever events or circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and therefore would require a write-down. We have incurred impairment charges in the past and may do so again in the future. Any impairment could be substantial and have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our reserve-based credit facility, which in turn may adversely affect our ability to make cash distributions to our unitholders.

Due to our lack of asset and geographic diversification, adverse developments in our core operating areas would affect our results of operations, reduce our operating cash flows and impact our profitability.

We rely exclusively on sales of the oil and natural gas that we produce. Furthermore, the majority of our assets is located in the Mid-Continent region of the United States and is predominantly coalbed methane natural gas. We currently have a limited amount of drilling opportunities in our existing asset base that enable us to focus on oil completions. Due to our lack of diversification in asset type, commodity type and location, an adverse development in the oil and natural gas business or our geographic area 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 to make any additional capital investments or to make any 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 Cherokee Basin to Macquarie Energy LLC; Keystone Gas Corporation; Scissortail Energy, LLC; Cotton Valley Compression, L.L.C.; Cherokee Basin Pipeline, LLC and ONEOK Energy Services Company, L.P. Our oil production in the Cherokee Basin is primarily purchased by Sunoco Partners Marketing and Terminals, L.P and Coffeyville Resources Refining and Marketing, LLC. Our natural gas production in the Woodford Shale and our oil production in the Central Kansas Uplift are marketed by the operators of the wells. Our oil and natural gas production in the onshore Texas and Louisiana Gulf Coast region is marketed by the operators of our properties. To the extent these or other customers reduce the volumes of oil and natural gas that they purchase from us and are not replaced by new customers, or the market prices for oil and natural gas decline in our market areas, our revenues and cash available for distribution could decline.

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

Oil and natural gas operations in our operating areas are often adversely affected by seasonal weather conditions, primarily during periods of severe weather or rainfall, and during periods of extreme cold. We face the risk that power outages and other damages resulting from tornados, ice storms, flooding and other strong storms or weather events will prevent us from operating our wells in an optimal manner. These weather conditions may reduce our oil and natural gas production, which could impact or reduce our future operating cash flows.

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

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

Shortages of drilling rigs, supplies, oilfield services, equipment and crews could delay our operations and reduce our future operating cash flows and cash available to make future investments or pay distributions.

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, reduce our operating cash flows and cash available to make future investments or pay distributions.

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

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough oil and natural gas to be commercially viable after drilling, operating and other costs. If we drill future wells that we identify as dry holes, our drilling success rate would decline, which could have a material adverse impact on our business, financial position or results of operations.

We may be unable to compete effectively with larger companies in the oil and natural gas industry, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel, and we compete with other companies that have greater resources. Many of our competitors are major independent oil and natural gas companies and possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial and personnel resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent on our ability to evaluate, select and finance the acquisition of suitable properties and our ability to consummate transactions in a highly competitive environment. Factors that affect our ability to acquire properties include availability of desirable acquisition targets, staff and resources to identify and evaluate properties and available funds. 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, there is substantial competition for investment capital in the oil and natural gas industry. Other 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, local and other laws and regulations. Our inability to compete effectively with other companies could have a material adverse effect on our business activities, financial condition and results of operations.

Acquisitions involve potential risks that could adversely impact our future growth and our ability to pay distributions to our unitholders.

Any acquisition involves potential risks, including, among other things:

•the risk that reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;

• the risk of title defects discovered after closing;

" inaccurate assumptions about revenues and costs, including synergies;
" significant increases in our indebtedness and working capital requirements;

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" an inability to transition and integrate successfully or timely the businesses we acquire;
" the cost of transition and integration of data systems and processes;
" the potential environmental problems and costs;
" the assumptions of unknown liabilities;
" limitations on rights to indemnity from the seller;
" the diversion of management's attention from other business concerns;
" increased demands on existing personnel and on our organizational structure;
" disputes arising out of acquisitions;
" customer or key employee losses of the acquired businesses; and
" the failure to realize expected growth or profitability.

The scope and cost of these risks may ultimately be materially greater than estimated at the time of the acquisition. Further, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely impact our future growth and our ability to pay distributions.

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

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

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

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

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

The operations of our wells, gathering systems, pipelines and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. Certain environmental statues, including RCRA, CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of or otherwise released. In addition, an accidental release from one of our wells or gathering pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary, and these costs may not be recoverable from insurance. For a more detailed discussion of environmental and regulatory matters impacting our business, see "Item 1. Business-Operations-Environmental Matters and Regulation".

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

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

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

We may face unanticipated water disposal or processing 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 treat or dispose of this produced water may increase if any of the following occur:

•we cannot renew or obtain future permits from applicable regulatory agencies;

•water of lesser quality or requiring additional treatment is produced;

•our wells produce excess water; or

•new laws and regulations require water to be disposed of or treated in a different manner.

Risks Related to Financing and Credit Environment

We may not be able to extend, replace or refinance our reserve-based credit facility on terms reasonably acceptable to us, or at all, which could materially and adversely affect our business, liquidity, cash flows and prospects.

Our reserve-based credit facility matures on May 30, 2017. We may not be able to extend, replace or refinance our existing reserve-based credit facility on terms reasonably acceptable to us, or at all, with our existing syndicate of banks or with replacement banks. In addition, we may not be able to access other external financial resources sufficient to enable us to repay the debt outstanding under our reserve-based credit facility upon its maturity. Any of the foregoing could materially and adversely affect our business, liquidity, cash flows and prospects.

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 there under 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 existing reserve-based credit facility matures on May 30, 2017. 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 re-determined semi-annually, and may be re-determined at our request more frequently and by the lenders in their sole discretion based on reserve reports prepared by reserve engineers, using, among other things, the oil and natural gas prices existing at the time. The lenders can unilaterally adjust our borrowing base and the borrowings permitted to be outstanding under the reserve-based credit facility. Any increase in our borrowing base requires the consent of all the lenders. Outstanding borrowings in excess of our borrowing base must be repaid, or we must pledge other oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the reserve-based credit facility.

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

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

We have the ability to pay distributions to unitholders under our reserve-based credit facility from available cash, including cash from borrowings under the reserve-based credit facility, as long as no event of default exists and provided that no distribution to unitholders may be made if the borrowings outstanding, net of available cash, under our reserve-based credit facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. At December 31, 2013, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions. Our ability to pay distributions to our unitholders in any quarter will be solely dependent on our ability to generate sufficient cash from our operations and is subject to the approval of our board of managers.

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

Disruptions in the capital and credit markets could limit our ability to access these markets or significantly increase our cost to borrow. Some lenders may increase interest rates, enact tighter lending standards, refuse to refinance existing debt at maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. If we are unable to access the capital markets on favorable terms, our ability to make acquisitions and pay distributions could be affected.

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, we may not be able to reinvest in our business, maintain our production and operating cash flow or our ability to make any distributions.

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 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 reserve-based credit facility, as well as by general economic conditions, world-wide credit and market conditions and contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining the necessary funds needed to finance our capital expenditures, the terms of such financings could limit our ability to pay distributions to our unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional securities may result in significant unitholder dilution and an increase in the aggregate amount of cash required to maintain any then-current distribution rate, which could adversely impact our financial condition and our ability to pay distributions at the then-current distribution rate.

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, vendors, lenders in our reserve-based credit facility and counterparties to our hedging arrangements. Some of our customers, vendors, lenders 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 these and other parties with which we enter into transactions as a normal part of our business activities. Any nonpayment or nonperformance by our customers, vendors, lenders 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 and financial tests contained in our existing and future credit and debt instruments may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

•increased cash flow required to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available to fund operations, capital expenditures, future business development or 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 debt 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 debt, 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 maintain or increase our production levels and to otherwise pursue our business plan. This debt may restrict our ability to make distributions to our unitholders and service our debt obligations.

Our business requires a significant amount of capital expenditures to maintain and grow production levels. If prices were to decline for an extended period of time, if the costs of our acquisition and development operations were to increase substantially or if events were to occur which reduced our revenues or increased our costs, we may be required to borrow significant amounts in the future to enable us to finance the expenditures necessary to replace the reserves we produce. The cost of the borrowings and our obligations to repay the borrowings will reduce amounts otherwise available for distributions to our unitholders.

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

During periods of 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. As we have hedged a large percentage of our future expected production volumes, the cash flow generated by that future hedged production will be capped. If any of our operating, administrative or capital costs were to increase as a result of inflation or any temporary or long-term increase in the cost of goods and services, such a cap could have a material adverse effect on our business, financial condition, results of operations, ability to pay distributions and the market price of our common units.

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

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt or other interest-bearing 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 our operating or capital activities or for any distribution to unitholders.

The swaps regulatory provisions of the Dodd-Frank Act and the rules adopted thereunder could have an adverse impact on our ability to hedge risks associated with our business and on our results of operations and cash flows.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) establishes federal oversight and regulation of the over-the-counter (OTC) derivatives market and entities, such as us, that participate in that market. The provisions of that title of the Dodd-Frank Act and the rules of the Commodity Future Trading Commission (CFTC) and the SEC adopted and proposed to be adopted thereunder, regulate certain swaps entities, require clearing of certain swaps by clearing organizations and execution of certain swaps on contract markets or swap execution facilities, and require certain reporting and recordkeeping of swaps. They also give the CFTC the authority to establish limits on the positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, including Henry Hub natural gas, held by market participants, with exceptions for certain bona fide hedging transactions. The CFTC's rules establishing position limits were vacated by a federal district court in September 2012. However, on November 5, 2013, the CFTC proposed new position limits rules that would modify and expand the applicability of position limits on certain core futures and equivalent swaps contracts for or linked to certain physical commodities, including Henry Hub natural gas, that market participants could hold with exceptions for certain bona fide hedging transactions.

The CFTC has designated certain interest rate swaps and certain credit default swaps for mandatory clearing and set compliance dates for three different categories of market participants who are parties to such swaps, the earliest of which was March 11, 2013 and the latest of which was September 9, 2013. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing and trade execution requirements for our swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require our counterparties to require that we enter into credit support documentation and/or post initial and variation margin; however, the proposed margin rules are not yet final, and therefore the application of those provisions to us is uncertain at this time. Provisions of the Dodd-Frank Act may also cause our derivatives counterparties to spin off some or all of their derivatives activities to a separate entity, which could be our counterparty in future swaps and which entity may not be as creditworthy as the current counterparty.

The Dodd-Frank Act's swaps regulatory provisions and the related rules could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If, as a result of the swaps regulatory regime discussed above, we were to reduce our use of swaps to hedge our risks, such as commodity price risks that we encounter in our operations, our results of operations and cash flows may become more volatile and could be otherwise adversely affected.

In addition to the Dodd-Frank Act, in 2012, the European Market Infrastructure Regulation (EMIR) became effective. EMIR includes regulations related to the trading, reporting and clearing of derivatives and the regulations thereunder may impact our ability to maintain or enter into derivatives with certain of our European counterparties.

Risks Related to Our Distribution to Unitholders

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

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

In order for us to make a distribution from available cash under our reserve-based credit facility, our outstanding debt balances, net of available cash, must be less than 90% of our borrowing base, as determined by our lenders, after giving effect to the proposed distribution. Our available cash excludes any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. We are subject to additional future borrowing base redeterminations before our reserve-based credit facility matures in May 2017 and cannot forecast the level at which our lenders will set our future borrowing base. If our lenders further reduce our borrowing base because of any of the numerous factors generally described in this caption "Risk Factors," our outstanding debt balances, net of available cash, may exceed 90% of the borrowing base, as determined by our lenders, and we may be unable to resume our quarterly distributions or may again have to suspend our quarterly distributions. If we do not achieve our expected operational results and we may not be able to resume, maintain or increase quarterly distributions, which may cause the market price of our common units to decline substantially.

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

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

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

Oil and natural gas prices are very volatile. If commodity prices decline significantly for a temporary or prolonged period, our cash from operations may decline and may adversely impact our ability to invest in new drilling opportunities, our financial condition and our profitability.

Our revenue, profitability and cash flow depend upon the prices and demand for oil and natural gas and a drop in prices can significantly affect our financial results and impede our growth. Changes in oil and natural gas prices have a significant impact on the value of our reserves and on our cash flow. In particular, declines in commodity prices will reduce the value of our reserves, our cash flow, our ability to borrow money or raise capital and our ability to pay distributions. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as: the domestic and foreign supply of and demand for oil and natural gas; the price and level of foreign imports of oil and natural gas; the level of consumer product demand; weather conditions; overall domestic and global economic conditions; political and economic conditions in oil and natural gas producing countries, including those in West Africa, the Middle East and South America; the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; the impact of U.S. dollar exchange rates on oil and natural gas prices; technological advances affecting energy consumption; domestic and foreign governmental regulations and taxation; the impact of energy conservation efforts; the costs, proximity and capacity of oil and natural gas pipelines and other transportation facilities; the price and availability of alternative fuels and the increase in the supply of natural gas due to the development of natural gas.

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

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

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

•changes in our reserves;

•changes in oil and natural gas prices;

•changes in labor and drilling costs;

•our ability to acquire, locate and produce reserves;

•changes in leasehold acquisition or concession costs; and

•government regulations relating to safety, taxation and the environment.

Our significant maintenance capital expenditures will reduce the amount of cash we may have available for distribution to our unitholders. In addition, our actual capital expenditures will vary from quarter to quarter. If we fail to make sufficient capital expenditures, our future production levels will decline which will materially and adversely affect our future revenues and any 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 operating 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 potential change by our conflicts committee of our board of managers at least once a year. In years when our estimated maintenance capital expenditures are higher than actual maintenance capital expenditures, the amount of cash available for distribution to unitholders will be lower than if actual maintenance capital expenditures were deducted from operating surplus. If we underestimate the appropriate level of estimated maintenance capital expenditures, we may have less cash available for distribution in future periods when actual capital expenditures begin to exceed our previous estimates. Over time, if we do not set aside sufficient cash reserves or have available sufficient sources of financing and make sufficient expenditures to maintain our asset base, we will be unable to pay distributions. CEP currently considers maintenance capital the minimum capital requirement to hold Adjusted EBITDA flat for a multi-year period.

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

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

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

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

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

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

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

Our ability to grow our business 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 flow per unit. We may be unable to make such acquisitions if we are:

•unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;

•unable to obtain financing for these acquisitions on economically acceptable terms; or

•outbid by competitors.

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

Risks Related to Our Structure and Our Major Unitholders

The sale by our major unitholders of their equity interests in the future could reduce the market price of our outstanding common units.

PostRock indirectly owned approximately 20.8% of our outstanding common units and 30% of our outstanding Class A units as of December 31, 2013, or an aggregate 21.3% interest in us. SOG owned approximately 16.6% of our outstanding common units and 70% of our outstanding Class A units as of December 31, 2013, or an aggregate 19.5% interest in us. If PostRock or SOG was to sell some or a substantial portion of its interest in us, it could reduce the market price of our outstanding common units.

PostRock, SOG and Exelon may transfer their interests in us to a third party without common unitholder consent.

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

Members of our board of managers, our executive officers, PostRock and its affiliates including CEPM, SOG and its affiliates including SEP I and Exelon and its affiliates including CEPH, may have conflicts of interest with us. Our operating 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 and SEP I, the holders of our Class A units. Conflicts of interest may arise between us and our unitholders and members of our board of managers or our executive officers, PostRock and its affiliates including CEPM, SOG and its affiliates including SEP I, and Exelon and its affiliates including CEPH. These potential conflicts may relate to the divergent interests of these parties. Situations in which the interests of members of our board of managers, our executive officers, or PostRock, SOG, Exelon and their affiliates, including CEPM, SEP I and CEPH, may differ from interests of owners of common units include, among others, the following situations:

•our operating 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 operating agreement nor any other agreement requires PostRock, SOG, Exelon or any of their affiliates to pursue a business strategy that favors us. Directors and officers of PostRock, SOG, Exelon, CEPM, SEP I and CEPH have a fiduciary duty while acting in their capacity as such a director or officer of such entity to make decisions in the best interests of such entities' stockholders, which may be contrary to our best interests;

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

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

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

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

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

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

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

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

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

•mergers and consolidations;

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

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

•any transaction which has the effect of increasing the proportionate ownership of the interested unitholder in the Company and

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

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

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

Our operating agreement confers upon our Class A unitholders certain voting rights which may limit transactions which we may do.

Our operating agreement contains provisions that confer upon our Class A unitholders, currently subsidiaries of PostRock and SOG, certain voting rights including:

•the right to elect two members to our board of managers, with such persons only being able to be removed by the Class A unitholders, and the right to consent to any increase in the size of our board of managers;

•the right to block the sale of all or substantially all of the assets of the Company and

•the right to block a dissolution or, except under certain circumstances, merger or conversion of the Company.

These provisions limit common unitholders’ ability to affect certain business transactions which the Class A unitholders oppose.

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

Our operating agreement restricts the voting rights of common unitholders by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than CEPM (a subsidiary of PostRock), SEP I (a subsidiary of SOG), CEPH (a subsidiary of Exelon), or their affiliates or transferees and persons who acquire such units with the prior approval of our board of managers, cannot vote on any matter. Our operating 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 operating 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 operating agreement limits and modifies our managers' and officers' fiduciary duties.

Our operating agreement contains provisions that modify and limit our managers' and officers' fiduciary duties to us and our unitholders. For example, our operating 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 a liability to repay distributions.

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

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

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

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

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

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

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

•changes in market valuations of similar companies;

•departures of key personnel;

•commencement of or involvement in litigation;

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

•variations in the amount of any quarterly distributions;

•future interest rates and expectations of inflation;

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

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

•changes in government regulations, taxation or laws impacting businesses, the oil and natural gas industry or publicly traded partnerships;

•changes in the general condition of global economies that impact commodities and financial markets;

•changes in general conditions in the United States (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

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.

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

Unitholders are required to pay U.S. federal income and other taxes and, in some cases, state and local income taxes, on their share of our taxable income, whether or not they receive cash distributions from us. Generally, should we generate taxable income for a particular tax year and not pay any cash distributions, our unitholders will be required to pay the actual U.S. federal income tax liability that results from their share of such taxable income even though they received no cash distributions from us.

During 2013, we did not pay any cash distributions on our units. Since we generated taxable income allocable to our unitholders for the 2013 tax year, unitholders who held our common units during 2013 did not receive cash distributions from us sufficient to pay any actual tax liability that resulted from their share of such 2013 taxable income. Further, if we generate taxable income from either operations or the sale of assets in future years and do not distribute the resulting cash, our unitholders may not receive sufficient cash distributions to pay the actual tax liability that results from their allocable share of our taxable income. The majority of the proceeds generated in 2013 from the sale of our properties in the Black Warrior Basin was used to pay down debt and did not result in sufficient distributions to unitholders to pay any actual tax liability of each unitholder attributable to such sale.

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by states and localities. If the Internal Revenue Service (IRS) were to treat us as a corporation for U.S. federal income tax purposes or if we were to become subject to a material amount of entity-level taxation for state or local tax purposes, then our cash available for distribution would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on us being treated as a partnership for U.S. federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for U.S. federal income tax purposes unless it satisfies a “qualifying income” requirement. Based on our current operations we believe that we satisfy the qualifying income requirement and will be treated as a partnership. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate income tax rates, which is currently at a maximum marginal rate of 35%, and would likely pay state and local income tax at varying rates. Distributions to unitholders would generally be taxed as corporate distributions, and no income, gains, losses, deductions or credits would flow through to the unitholders. Because a tax would be imposed on us as a corporation, our cash available for distribution to our unitholders would be reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders likely causing a substantial reduction in the value of our common units.

Our operating 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 operating 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 U.S. 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, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could adversely affect an investment in our common units.

At the state level, changes in current state law may subject us to additional entity-level taxation by individual states. Due to widespread state budget deficits and for other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may materially reduce the cash available for distribution to our unitholders.

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

Both the Obama Administration and members of Congress have during past U.S. legislative sessions proposed changes that would, if enacted into law, make significant changes to U.S. tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Other proposed changes could affect our ability to remain taxable as a partnership for U.S. federal income tax purposes. The passage of any legislation with similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our common units.

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

We will be considered to have technically terminated our existing partnership and having formed a new partnership for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income for the year of termination. 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 also result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for U.S. federal income tax purposes, but instead we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we were unable to determine in a timely manner that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief procedure whereby, if a publicly traded partnership that has a technical termination request, the partnership will only have to provide one Schedule K-1 to unitholders for the year, and the IRS grants special relief among other things, notwithstanding two partnership tax years resulting from the technical termination.

A successful IRS contest of the U.S. 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 U.S. federal income tax purposes or any other matter affecting 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 common 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 U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and may be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file U. S. 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 depletion, 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 common unitholder sells common units, the unitholder will recognize gain or loss equal to the difference between the amount realized and the tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in its common units, the amount if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if it sells such common units at a price greater than its tax basis in those common units, even if the price received is less than its original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to the unitholder. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units 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 in states where they do not live as a result of an investment in our common units.

In addition to U.S. federal income taxes, our unitholders are likely subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not reside in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently are registered to do business, or own assets in Texas, Alabama, Oklahoma, Louisiana and Kansas. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all U.S. federal, state and local tax returns that may be required of such unitholder.

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, our allocation of the

Section 743(b) adjustment attributable to our tangible and intangible assets and our allocations of income, gain, loss and deduction between the holders of our management incentive interests and certain of our common unitholders.

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

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

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

A unitholder whose 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. 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 consult with their tax advisor about whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

Forward-Looking Statements

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

- business strategy;
- acquisition strategy;
- financial strategy;
- ability to resume, maintain and grow distributions;

•drilling locations;

•oil, natural gas and natural gas liquids reserves;

•realized oil, natural gas and natural gas liquids prices;

•production volumes;

•lease operating expenses, general and administrative expenses and development costs;

•future operating results and;

•plans, objectives, expectations, forecasts, outlook and intentions.

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

The forward-looking statements contained in this Annual Report on Form 10-K are largely based on 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. The forward-looking statements speak only as of the date made, and other than as required by law, we do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

Our obligations under our reserve-based credit facility are secured by mortgages on our oil and natural gas properties, as well as a pledge of all ownership interests in our material subsidiaries. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—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

On August 30, 2013, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPM, Gary M. Pittman and John R. Collins against the Company, certain of its officers and managers, SOG and SEP I (the PostRock litigation) in connection with the Company’s closing on August 9, 2013 of the purchase of oil and natural gas properties from SEP I and the issuance of units in connection therewith. The plaintiffs contend, among other things, that the issuance of the units to SEP I in connection with the acquisition was not permitted under the Company’s operating agreement, that Messrs. Pittman and Collins should not have been removed as the Class A managers of the Company’s board of managers, and that SEP I, SOG and our current Class A managers participated in the bad faith conduct of the other defendants and interfered with CEPM’s contractual rights under the Company’s operating agreement. The plaintiffs allege claims against the Company and certain of its managers and officers relating to breach of contract, breach of the duty of good faith, and breach of the implied covenant of good faith and fair dealing; the plaintiffs also allege aiding and abetting and tortuous interference claims against SOG, SEP I and our current Class A managers. The plaintiffs seek, among other things, declaratory relief reappointing Messrs. Pittman and Collins to the Company’s board of managers and removing our current Class A managers therefrom, and an injunction against the Company taking any further action outside the ordinary course of business during the pendency of the litigation, declaratory relief rescinding the units issued by the Company to SEP I, declaratory relief that CEPM has sole voting power with respect to the outstanding Class A units, declaratory relief that the Company officers and managers have breached fiduciary and contractual duties and are not entitled to indemnification from the Company as a result thereof, and monetary damages. The parties to the lawsuit are currently working on the terms of a settlement agreement. In anticipation of a settlement being reached, we have accrued a probable liability of $5.9 million.

On February 28, 2014, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPH against the Company (the Exelon Litigation) seeking repayment of suspended distributions in relation to the Class D Interests held by CEPH. In 2006, Constellation Holding, Inc (CHI), which merged with and into CEPH in December 2012, purchased the Company’s Class D Interests for $8.0 million. The $8.0 million was to be repaid to CEPH in quarterly distributions of $333,333.33 over a period of six years; however, these distributions could be temporarily suspended if a dispute arose over pricing formulas related to the sale of natural gas from the Robinson's Bend properties. A dispute arose, so the distributions were suspended pursuant to the Company's operating agreement and never reinstated. CEPH contends, among other things, that the Company breached its contract to pay the quarterly distributions, acted in bad faith and received unjust enrichment by suspending the quarterly distributions. The Company believes that the allegations contained in the lawsuit are without merit and intends to vigorously defend itself against the claims raised in the complaint. In conjunction with its defense in the Exelon Litigation, the Company anticipates that it will incur legal and other costs that may have a material effect on available cash which could impact CEP's ability to make distributions.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our common units are listed on the NYSE MKT under the symbol "CEP." On March 21, 2014, there were 28,399,502 common units outstanding and 56 unitholders of record. On March 21, 2014, the market price for our common units was $2.69 per unit, resulting in an aggregate market value of units held by non-affiliates of approximately $47.8 million. The following table presents the high and low closing price for our common units during the periods indicated.

	Common Stock	
	High	Low
2013		
First Quarter	$ 1.82	$ 1.17
Second Quarter	$ 2.13	$ 1.50
Third Quarter	$ 2.95	$ 1.85
Fourth Quarter	$ 2.47	$ 2.10
2012		
First Quarter	$ 2.80	$ 1.81
Second Quarter	$ 2.88	$ 1.55
Third Quarter	$ 1.57	$ 1.21
Fourth Quarter	$ 1.57	$ 1.18

We have not paid distributions on our common units since June 2009.

Subject to the terms of our reserve-based credit facility, our operating agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date. Available cash generally means, for any quarter ending prior to liquidation:

(a) the sum of:

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

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

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

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

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

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

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

Item 6. Selected Financial Data

To measure our business, we use a non-GAAP financial measure, Adjusted EBITDA. This measure is not calculated or presented in accordance with accounting principles generally accepted in the United States (U.S. GAAP). We explain this measure and reconcile it to net income, the most directly comparable financial measure calculated and presented in accordance with U.S. GAAP below.

Non-GAAP Financial Measure—Adjusted EBITDA

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

•interest (income) expense, net which includes:

-interest expense

-interest expense (gain)/loss mark-to-market activities

-interest (income);

•depreciation, depletion and amortization;

•asset impairments;

•accretion expense;

•loss on sale of assets;

•unit-based compensation programs;

•gain on mark-to-market activities

•loss on mark-to-market activities and

•loss on discontinued operations.

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 U.S. GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

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

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

	For the year ended December 31,	
	2013	2012
Reconciliation of Net Loss to Adjusted EBITDA:		
Net loss	$ (28,543)	$ (86,543)
Adjusted by:		
Interest expense, net	3,150	5,733
Depreciation, depletion and amortization	18,972	11,732
Asset impairments	2,357	109
Accretion expense	519	459
Loss on sale of assets	4	7
Unit-based compensation programs	1,049	1,497
Gain on mark-to-market activities	(1,713)	(2,853)
Loss on mark-to-market activities	18,994	11,559
Loss on discontinued operations	2,686	77,081
Adjusted EBITDA	$ 17,475	$ 18,781

Our Adjusted EBITDA of $17.5 million for the year ended December 31, 2013, was lower than our Adjusted EBITDA of $18.8 million for the same period of 2012. During 2013, we sold all of our Robinson’s Bend Field assets and acquired oil, natural gas and natural gas liquids properties in Texas and Louisiana. As a result of these transactions, we increased our oil production and oil revenue. Market prices were higher for oil and natural gas during 2013, which helped increase our Adjusted EBITDA, but was offset by higher legal fees pertaining to the PostRock litigation. We believe the Adjusted EBITDA should not impact our future ability to comply with the financial covenants contained in our reserve-based credit facility as we reduced the amount of our outstanding debt with the one-time cash payment we received from the sale of the Robinson’s Bend Field assets.

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

The following discussion and analysis should be read in conjunction with the “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 in 2005 to acquire oil and natural gas properties. Our proved reserves are located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas and in Texas and Louisiana. Our primary business objective is to create long-term value and to generate stable cash flows allowing us to invest in our business to grow our reserves and production. We plan to achieve our objective by executing our business strategy, which is to:

•organically grow our business by increasing reserves and production through what we believe to be low-risk development drilling that focuses on capital efficient production growth and oil opportunities on our existing properties in the Mid-Continent region and in Texas and Louisiana;

•reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient and effective hedging programs; and

•make accretive, right-sized acquisitions of oil and natural gas properties characterized by a high percentage of proved developed oil and natural gas reserves with long-lived, stable production and low-risk drilling opportunities.

We completed our initial public offering on November 20, 2006, and our Class B common units are currently listed on the NYSE MKT 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," or the "Company" means Constellation Energy Partners LLC and its subsidiaries. Referer in this Annual Report on Form 10-K to "PostRock" and "CEPM" are to PostRock Energy Corporation and its subsidiary Constellation Energy Partners Management, LLC, respectively. References in this Annual Report on Form 10-K to "Exelon" and "CEPH" are to Exelon Corporation and its subsidiary Constellation Energy Partners Holdings, LLC, respectively. References in this Annual Report on Form 10-K to "SOG" and "SEP I" are to Sanchez Oil & Gas Corporation and its subsidiary, Sanchez Energy Partners I, LP, respectively. References in this Annual Report on Form 10-K to "Constellation" are to Constellation Energy Group, Inc.

Some key highlights of our business activities through December 31, 2013 were:

•We sold our Robinson's Bend Field assets in the Black Warrior Basin in Alabama and used a portion of the proceeds from that sale to reduce our outstanding debt. As a result of this sale, amounts related to the Robinson's Bend Field assets have been reported as discontinued operations in 2013. All prior year information relating to the Robinson's Bend Field assets has been restated as discontinued operations, and all information reported or discussed in this Annual Report on Form 10-K reflects the treatment of the Robinson's Bend Field assets as discontinued operations.

•We amended our reserve-based credit facility to extend its maturity to May 2017 and expand our borrowing capacity.

•We acquired producing oil and natural gas assets in Texas and Louisiana from SEP I.

•We executed a capital plan that allowed us to expand our oil production from 2010 to 2013 by 262.3% and increased our proved oil reserves to 2.2 million barrels at December 31, 2013. Oil revenues accounted for 50.5% of our total unhedged revenue stream in 2013.

•We have reduced our outstanding debt by 77.0% from a high of $220.0 million in 2009 to $50.7 million.

In 2014, we intend to focus our efforts on developing oil opportunities on our existing properties in the Mid-Continent region and in Texas and Louisiana, while pursuing opportunities to acquire additional properties in our operating area or merger and acquisition opportunities that could lead to enhanced unitholder value. For additional information on our business plan for 2014, refer below to "Outlook."

Significant Operational Factors in 2013

• Realized Prices. Our average realized price for the twelve months ended December 31, 2013, including hedge settlements, was $7.49 per Mcfe and $5.56 per Mcfe excluding hedge settlements. After deducting the cost of sales associated with third party gathering, our average realized prices were $7.32 per Mcfe including hedge settlements and $5.39 per Mcfe excluding hedge settlements.

•Production. Our production for the twelve months ended December 31, 2013, was approximately 8.2 Bcfe, or an average of 22,433 Mcfe per day compared with approximately 8.2 Bcfe, or an average of 22,418 Mcfe per day for the twelve months ended December 31, 2012.

•Capital Expenditures and Drilling Results. For the twelve months ended December 31, 2013, we spent approximately $35.9 million in cash capital expenditures, consisting of $15.3 million in development expenditures focused on oil completions in the Cherokee Basin, $0.1 million to acquire certain additional natural gas wells in the Cherokee Basin, $20.1 million to acquire SEP I properties, and $0.4 million in development expenditures focused on SEP I acquired properties. We completed 64 net wells and 15 net recompletions during 2013 and had 6 net wells and recompletions in progress at December 31, 2013.

- Oil and Natural Gas Reserves. Our total year end 2013 proved reserves were 91.3 Bcfe, which is 47.7 Bcfe higher than our year end 2012 proved reserves of 43.6 Bcfe, due to the sale of our Black Warrior Basin assets, partially offset by higher SEC natural gas and oil prices and the purchase of the SEP I properties in Texas and Louisiana. Our 2013 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. We increased our proved oil reserves from 1.1 MBbl to 2.2 MBbl or by 100% by focusing our capital programs on drilling locations that have oil completions. Any of our locations that are scheduled to be drilled after five years are classified as probable or possible reserves if they are economic. Our reserves are 85% natural gas and are sensitive to lower SEC-required prices for natural gas and basis differentials in the Mid-Continent region. The 12-month average SEC-required price used to prepare our reserve report was $3.71 per Mcf. 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 December 31, 2013, we reduced our outstanding debt from a high of $220.0 million in 2009 to $50.7 million, or by 77.0%, which currently leaves us with $4.3 million of funds available for borrowing under our reserve-based credit facility which matures on May 30, 2017.

•Hedging Activities. All of our derivatives are accounted for as mark-to-market activities. For the twelve months ended December 31, 2013, the non-cash mark-to-market loss was approximately $17.3 million, compared to non-cash mark-to-market loss of $8.7 million for the same period in 2012.

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

•Operating Expense Reductions. We are currently implementing strategies to lower our operating expenses. For the year ended December 31, 2013, we have reduced our lease operating expenses by 2.8%, compared to the same period in 2012 and reduced our general and administrative expenses by 10% when not including litigation and accrued settlement charges in the fourth quarter of 2013.

Significant Market Factors

•PostRock as an "Interested Unitholder". In 2011, PostRock acquired certain of our Class A and Class B common units in two separate transactions which represented a 21.3% ownership interest in us as of December 31, 2013. Approval of the purchase of these units was neither required nor given by our board of managers or conflicts committee. We believe PostRock is now an "interested unitholder" under Section 203 of the Delaware General Corporation Law, which is applicable to us pursuant to our operating agreement. Section 203, as it applies to us, prohibits an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in business combinations with us for three years following the time such person becomes an interested unitholder without the approval of our board of managers and the vote of 66 2/3% of our outstanding Class B common units, excluding those held by the interested unitholder. Section 203 broadly defines "business combination" to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. In addition to limiting our ability to enter into transactions with PostRock or its affiliates, this provision of our operating 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. We believe the Section 203 restrictions related to these unit purchases expire in December 2014.

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,		2013 vs. 2012 Variance	
	2013	2012	$	%
Revenues:				
Natural gas sales at market price	$ 20,999	$ 15,746	5,253	33.4 %
Natural gas hedge settlements	15,550	23,654	(8,104)	(34.3) %
Natural gas mark-to-market activities	(16,528)	(8,538)	(7,990)	(93.6) %
Natural gas total	20,021	30,862	(10,841)	(35.1) %
Oil and liquids sales	21,456	11,923	9,533	80.0 %
Oil hedge settlements	245	753	(508)	(67.5) %
Oil mark-to-market activities	(753)	(168)	(585)	(348.2) %
Oil and liquids total	20,948	12,508	8,440	67.5 %
Miscellaneous income	3,108	3,157	(49)	(1.6) %
Total revenues	44,077	46,527	(2,450)	(5.3) %
Operating expenses:				
Lease operating expenses	18,858	19,411	(553)	(2.8) %
Cost of sales	1,455	1,299	156	12.0 %
Production taxes	2,601	1,646	955	58.0 %
General and administrative	22,214	15,747	6,467	41.1 %
Loss on sale of assets	4	7	(3)	(42.9) %
Depreciation, depletion and amortization	18,972	11,732	7,240	61.7 %
Asset impairments	2,357	109	2,248	2,062.4 %
Accretion expenses	519	459	60	13.1 %
Total operating expenses	66,980	50,410	16,570	32.9 %
Other expenses (income):				
Interest expense	6,798	6,891	(93)	(1.3) %
Interest expense - gain from mark-to-market activities	(3,648)	(1,157)	(2,491)	215.3 %
Interest income	-	(1)	1	(100.0) %
Other income	(196)	(154)	(42)	27.3 %
Total other expenses (income)	2,954	5,579	(2,625)	(47.1) %
Total expenses	69,934	55,989	13,945	24.9 %
Loss from discontinued operations	(2,686)	(77,081)	74,395	(96.5) %
Net loss	$ (28,543)	$ (86,543)	58,000	(67.0) %
Net production:				
Natural gas production (MMcf)	6,862	7,482	(620)	(8.3) %
Oil and liquids production (MBbl)	221	121	100	82.6 %
Total production (Mmcfe)	8,188	8,205	(17)	(0.2) %
Average daily production (Mcfe/d)	22,433	22,418	15	0.1 %
Average sales prices:				

Natural gas price per Mcf with hedge settlement	$ 5.78	$ 5.69	0.09	1.6	%
Natural gas price per Mcf without hedge settlements	$ 3.51	$ 2.53	0.98	38.7	%
Oil and liquids price per Bbl with hedge settlements	$ 98.18	$ 105.22	(7.04)	(6.7)	%
Oil and liquids price per Bbl without hedge settlements	$ 97.07	$ 98.97	(1.89)	(1.9)	%
Total price per Mcfe with hedge settlements	$ 7.49	$ 6.73	0.76	11.3	%
Total price per Mcfe without hedge settlements	$ 5.56	$ 3.76	1.80	47.9	%
Total price per BOE with hedge settlements	$ 44.96	$ 40.38	4.58	11.3	%
Total price per BOE without hedge settlements	$ 33.39	$ 22.53	10.86	48.2	%
Average unit costs per Mcfe:					
Field operating expenses	$ 2.62	$ 2.57	0.05	1.9	%
Lease operating expenses	$ 2.30	$ 2.37	(0.07)	(3.0)	%
Production taxes	$ 0.32	$ 0.20	0.12	60.0	%
General and administrative expenses	$ 2.71	$ 1.92	0.79	41.4	%
General and administrative expenses without unit-based compensation	$ 2.59	$ 1.74	0.85	48.6	%
Depreciation, depletion and amortization	$ 2.32	$ 1.43	0.89	62.2	%

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

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Oil and natural gas sales. Unhedged natural gas sales increased $5.3 million, or 33.4%, to $21.0 million for the year ended December 31, 2013, compared to $15.7 million in 2012. Unhedged oil and liquid sales increased $9.5 million, or 80.0%, to $21.4 million for the year ended December 31, 2013, compared to $11.9 million for the same period in 2012. With hedges and mark-to-market activities, our total revenue decreased $2.4 million when compared to the same period in 2012. Of this decrease, $8.6 million was attributable to lower hedge settlements for our oil and natural gas commodity derivatives and $8.6 million was attributable to lower mark-to-market activities, partially offset by $14.8 million related to higher market prices for natural gas and oil. Production for the twelve months ended December 31, 2013 was 8.2 Bcfe, which was comparable to the same period in 2012. We hedged all of our actual consolidated production volumes sold through December 31, 2013, and approximately 81% of our actual production through December 31, 2012. In March 2013, we liquidated or repositioned certain of our hedges to ensure that our outstanding derivative positions in future periods are lower than our expected future natural gas production in those periods.

Cash hedge settlements received for our commodity derivatives were approximately $15.8 million for the year ended December 31, 2013. Cash hedge settlements received for our commodity derivatives were approximately $24.4 million for the year ended December 31, 2012. This difference is due to changes in hedge prices, hedged volumes and market prices for natural gas and oil during 2012 and 2013.

As discussed below, our non-cash mark-to-market activities decreased by $8.6 million for the year ended December 31, 2013, compared to the same period in 2012. Our realized prices before our hedging program decreased from 2012 to 2013 primarily due to net higher market prices for our natural gas production. This was offset by our hedging program and the mark-to-market gains and losses discussed below.

Hedging and mark-to-market activities. As of December 31, 2013, all of our hedges were accounted for as mark-to-market activities. For the year ended December 31, 2013, the non-cash mark-to-market loss was approximately $17.3 million as compared to a non-cash mark-to-market loss of approximately $8.7 million for the same period in 2012. The entire 2013 non-cash loss represented the impact of higher than expected future oil and natural gas prices on our derivative transactions that were being accounted for as mark-to-market activities.

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

For the year ended December 31, 2013, lease operating expenses decreased $0.5 million, or 2.8%, to $18.9 million, compared to expenses of $19.4 million for the same period in 2012. This $0.5 million decrease in lease operating expenses is related to $0.7 million in lower elective costs such as well servicing and repairs and maintenance and $0.5 million in lower insurance, partially offset by higher labor costs of $0.7 million.

For the year ended December 31, 2013, per unit lease operating expenses were $2.30 per Mcfe compared to $2.37 per Mcfe for the same period in 2012.

For the year ended December 31, 2013, production taxes increased $1.0 million, or 58.0%, to $2.6 million, compared to production taxes of $1.6 million for the same period in 2012. This increase is primarily the result of higher market prices for natural gas and oil in 2013.

Cost of sales. For the year ended December 31, 2013, cost of sales increased by $0.2 million, or 12.0%, to $1.5 million, compared to $1.3 million for the same period in 2012.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, professional fees, general business and public company expenses, and any other administrative costs not directly associated with field operations.

General and administrative expenses increased $6.5 million, or 41.1%, to $22.2 million for the year ended December 31, 2013, compared to $15.7 million for the same period in 2012. Our general and administrative expenses were higher in 2013, compared to 2012 because of $6.2 million in higher audit, consulting, and legal services, and $1.0 million in severance costs, partially offset by $0.5 million in decreased labor and incentive compensation costs and $0.2 million in decreased unit-based compensation costs. The increased legal fees are the result of the PostRock litigation and the anticipated settlement of $5.9 million.

Our per unit general and administrative costs were $2.71 per Mcfe for the year ended December 31, 2013, compared to $1.92 per Mcfe for the same period in 2012. This increase is attributable to an increase in total spending of $6.5 million.

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

Our depreciation, depletion and amortization expense for the year ended December 31, 2013 was $18.9 million, or $2.32 per Mcfe, compared to $11.7 million, or $1.43 per Mcfe, for the same period in 2012. This increase of $7.2 million, or 61.7%, reflects the decrease in our reserve base at December 31, 2012, primarily due to the impact of a lower SEC-required natural gas price used to calculate our reserves which resulted in negative reserve revisions, and increased expenditures incurred for our drilling programs in 2012. These revisions were partially offset by increased oil reserves as a result of our successful drilling programs We calculate depletion using units-of-production under the successful efforts method of accounting. Our other assets are depreciated using the straight line basis. We will use our 2013 year-end reserve report to record our depletion in the first three quarters of 2014 and our 2014 year-end reserve report to record our depletion in the fourth quarter of 2014.

Our asset impairment charges for the year ended December 31, 2013 were $2.3 million, compared to $0.1 million for the same period in 2012. Our impairment charges in 2013 were approximately $2.1 million to impair the value of our oil and natural gas fields in Texas and Louisiana and $0.2 million to impair certain of our wells in the Woodford Shale, both due to decreases in commodity pricing. Our impairment charges in 2012 were approximately $0.1 million to impair certain of our wells in the Woodford Shale. The impairment 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.

Interest expense. Net interest expense for the year ended December 31, 2013 decreased $2.6 million, or 45.1%, to approximately $3.1 million, compared to approximately $5.7 million in interest expense for the same period in 2012. This decrease was primarily due to $1.5 million in higher interest rate swap settlements, offset by $2.5 million lower non-cash mark-to-market losses on our interest rate swaps that are accounted for as mark-to-market activities and lower market interest rates resulting in lower interest expense of $1.6 million during 2013 as compared to the same period in 2012. At December 31, 2013, we had an outstanding balance under our reserve-based credit facility of $50.7 million, compared to $84.0 million at December 31, 2012.

Discontinued Operations. Loss from discontinued operations for the year ended December 31, 2013 decreased $74.4 million, or 96.5%, to a loss of $2.7 million, compared to a loss of $77.1 million in discontinued operations for the same period in 2012. Our discontinued operations represent the net loss associated with the sale of our Robinson’s Bend Field assets in the Black Warrior Basin of Alabama, in a transaction that closed on February 28, 2013, with an effective date of December 1, 2012. The loss in 2013 reflects a $3.1 million loss on the sale of the properties, only two months of income and lower depreciation expenses.

Liquidity and Capital Resources

During 2013, we utilized our cash flow from the sale of our Robinson’s Bend Field assets, as well as our cash flow from operations, as our primary sources of capital. Our primary use of capital during this time was for the reduction of outstanding debt, the acquisition of properties and the development of existing oil opportunities within our existing asset base in the Mid-Continent and Gulf Coast regions.

The primary focus of our business plan in 2013 was to use our excess operating cash flows to reduce our outstanding debt level while continuing a limited capital program focused on oil drilling and recompletions. Since we shifted our strategic focus to debt reduction, we have successfully reduced our outstanding debt balance from a high of $220.0 million in 2009 to $50.7 million as of December 31, 2013. This reduction in debt was achieved through a combination of the sale of our natural gas properties in the Black Warrior Basin of Alabama in 2013, the one-time restructuring of our NYMEX fixed-for-floating price swaps in 2011, the suspension of our cash distribution since 2009, the reduction of our capital expenditures since 2009, significant reductions in our operating expenses and the dedication of a significant portion of our operating cash flows to reducing debt.

Based upon our current business plan for 2014, we anticipate that we will continue to generate sufficient operating cash flows to meet our working capital needs and fund a planned capital expenditure program between $20.0 million and $22.0 million. We also anticipate that we will have funds available to pay the probable settlement related to the PostRock litigation of approximately $5.9 million. We will be monitoring the capital resources available to us to meet our future financial obligations and our planned 2014 capital expenditures. Our current expectation is that we will continue managing our business to operate within the cash flows that are generated. Given our focus on debt reduction, our quarterly distributions to our unitholders remained suspended through the fourth quarter of 2013. We were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business and the payment of fees and expenses) from which to pay distributions.

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 position and expected production levels in 2014, we anticipate that our cash flow from operations can meet our planned capital expenditures and other cash requirements for the next twelve months without increasing our debt. If needed, we may issue additional equity securities to raise additional capital. Future cash flows and our borrowing capacity are subject to a number of variables, including the level of oil and natural gas production, the market prices for those products and our hedge position. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain our reduced debt level, planned levels of capital expenditures, operating expenses or any cash distributions that we may make to unitholders.

During 2013, natural gas prices showed signs of recovery, while oil prices showed signs of tapering. We have a significant amount of our natural gas production hedged for 2014 and 2015 and our oil production hedged from 2014 through 2016. Our results will not be fully impacted by significant increases or decreases in oil and natural gas prices because of our hedging program. For 2014, we forecast our total net natural gas production of between 6.3 Bcf and 7.3 Bcf and our total net oil production of between 270,000 Bbls and 308,000 Bbls. After the sale of our Robinson's Bend Field in the Black Warrior Basin of Alabama, we executed transactions to liquidate and offset certain of our derivative positions to prevent us from being over hedged. We are now financially hedged on 94% of the midpoint guidance of our 2014 natural gas production guidance and 77% of the midpoint of our 2014 oil production guidance. For 2014, we have approximately 6.4 Bcfe of our natural gas production locked in at an effective fixed price of $5.75 per Mcfe with basis hedges on 4.4 Bcfe of our Mid-Continent natural gas production at an average differential of $0.39 per Mcfe. With respect to our 2014 oil production, we have hedges in place on approximately 222 MBbl at a fixed price of $94.70 per barrel. This hedge position locks in a significant portion of our expected operating cash flows for 2014, although we are still exposed to increases or decreases in oil and natural gas prices on any of our unhedged volumes. In the event of inflation increasing drilling and service costs, our hedging program will also limit our ability to have increased revenues recoup the higher costs, which could further impact our planned capital spending or operating expense levels.

Reserve-Based Credit Facility

In May 2013, we refinanced our $350.0 million reserve-based credit facility with Societe Generale as administrative and collateral agent and a syndicate of lenders, extending its maturity date to May 30, 2017 and increasing our borrowing base from $37.5 million to $55.0 million. 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 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, 2013, we had borrowed $50.7 million under our reserve-based credit facility and our borrowing base was $55.0 million. At December 31, 2013, the lenders and their percentage commitment in the reserve-based credit facility were Societe Generale (36.36%), OneWest Bank, FSB (36.36%) and BOKF NA, dba Bank of Oklahoma (27.28%).

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, 2013, no letters of credit were outstanding.

At our election, interest for borrowings is 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 is 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 and make certain loans, acquisitions, capital expenditures and investments. The reserve-based credit facility limits our ability to pay distributions to unitholders and permits us to hedge our projected monthly production, as discussed below, and the interest rate on our borrowings.

In addition, we are required to maintain (i) a ratio of Total Net Debt (defined as Debt (generally indebtedness permitted to be incurred by us under the reserve-based credit facility) less Available Cash (generally, cash, cash equivalents and cash reserves of the Company)) to Adjusted EBITDA (generally, for any period, the sum of consolidated net income for such period plus (minus) the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets, (gain) loss on sale of assets, exploration costs, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on derivatives and realized (gain) loss on cancelled derivatives, and other similar charges) of not more than 3.50 to 1.0; (ii) Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and (iii) consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities and current maturities of debt (to the extent such payments are not past due), of not less than 1.0 to 1.0, all calculated pursuant to the requirements under Accounting Standards Codification (ASC) Topic 815, Derivatives and Hedging; ASC Topic 410, Asset Retirement and Environmental Obligations and ASC Topic 360, Property, Plant and Equipment. All financial covenants are calculated using our consolidated financial information and are discussed below.

The reserve-based credit facility also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, guaranties not being valid under the reserve-based credit facility and a change of control. A change of control is generally defined as the occurrence of both of the following events (i) wholly-owned subsidiaries of Constellation Energy Group, Inc. are the owner of 20% or less of an interest in us (which has now occurred) and (ii) any person or group of persons acting in concert are the owner of more than 35% of an interest in us. These events have not both occurred, so a change in control had not occurred as of December 31, 2013. If an event of default occurs, the lenders will be able to accelerate the maturity of the reserve-based credit facility and exercise other rights and remedies. The reserve-based credit facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the reserve-based credit facility and would be in default, which could cause all of our existing indebtedness to become immediately due and payable.

The reserve-based credit facility limits our ability to pay distributions to unitholders. We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the reserve-based credit facility, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the reserve-based credit facility exceed 90% of our borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. As of December 31, 2013, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions.

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

The reserve-based credit facility contains no covenants related to PostRock's, Exelon's or SOG's ownership in us.

At December 31, 2013, 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, 2013, our actual Total Net Debt to actual Adjusted EBITDA ratio was 2.6 to 1.0, compared to a required ratio of not greater than 3.5 to 1.0; our actual ratio of consolidated current assets to consolidated current liabilities was 1.3 to 1.0, compared to a required ratio of not less than 1.0 to 1.0; and our actual Adjusted EBITDA to cash interest expense ratio was 9.3 to 1.0, compared to a required ratio of not less than 2.5 to 1.0.

If we are unable to remain in compliance with the financial covenants contained in our reserve-based credit facility or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of our reserve-based credit facility, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

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, 2013, our borrowing base was $55.0 million. The borrowing base is re-determined semi-annually, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas prices prevailing at such time. 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.

Discontinued Operations

We view periodic reserve sales as an opportunity to capture value, reduce reserve and price risk, in addition to being a source of funds for potentially higher rate of return on oil and natural gas exploration investments. We believe these periodic oil and natural gas property sales are an efficient strategy to meet our cash and liquidity needs by providing us with immediate cash, which would otherwise take years to realize through the production lives of the fields sold. We have in the past and could in the future continue to rely on the sales of assets to generate cash to fund our exploration investments and operations.

These sales bring forward future revenues and cash flows, but our longer term liquidity could be impaired to the extent our exploration efforts in our remaining properties are not successful in generating new discoveries, production, revenues and cash flows. Additionally, our longer term liquidity could be impaired due to the decrease in our inventory of producing properties that could be sold in future periods. Further, as a result of our recent property sale, our ability to collateralize bank borrowings is reduced, which increases our dependence on more expensive mezzanine debt and potential equity sales. The availability of such funds will depend upon prevailing market conditions and other factors over which we have no control, as well as our financial condition and results of operations.

Cash Flow from Operations

Our net cash flow provided by operating activities for the year ended December 31, 2013, was $15.2 million, compared to net cash flow provided by operating activities of $14.2 million for the same period in 2012. This increase in cash flow from operations was attributable to the impact of higher oil and natural gas sales of $42.5 million for 2013 compared to $27.7 million for the same time period in 2012, partially offset by losses on mark-to-market activities, increased general and administrative costs related to legal fees and the probable PostRock litigation settlement amount and increased operating costs as a result of our acquisition of oil and natural gas properties in Texas and Louisiana.

Our cash flow from operations is subject to many variables, the most significant of which are the volatility of oil and natural gas prices and our level of production of oil and natural gas. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through our development program or completing acquisitions, as well as the market prices of oil and natural gas and our hedging program. For additional information on our business plan for 2014, refer below to "Outlook."

Open Commodity Hedge Positions

We enter into hedging arrangements to reduce the impact of oil and natural gas price volatility on our operations. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to fund higher severance taxes, which are usually based on market prices for oil and natural gas. Our operating cash flows are also 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. All of our derivatives are with Societe Generale, a lender in our reserve-based credit facility, and The Bank of Nova Scotia. All of our derivatives are currently collateralized by the assets securing our reserve-based credit facility and therefore currently do not require the posting of cash collateral. This is significant since we are able to lock in 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 as of December 31, 2013, summarize, for the periods indicated, our hedges currently in place through December 31, 2016. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps—NYMEX (Henry Hub)

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For the quarter ended (in MMBtu)

	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2014	1,575,000	$ 5.75	1,592,500	$ 5.75	1,610,000	$ 5.75	1,610,000	$ 5.75	6,387,500	$ 5.75
2015	1,215,420	$ 4.25	1,153,487	$ 4.25	1,096,023	$ 4.26	1,050,219	$ 4.26	4,515,149	$ 4.25
2016	1,010,633	$ 4.21	967,290	$ 4.21	923,541	$ 4.21	893,568	$ 4.22	3,795,032	$ 4.21
									14,697,681	

MTM Fixed Price Basis Swaps– Enable Gas Transmission, LLC (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,		September 30,		December 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
2014	1,178,422	$ 0.39	1,133,022	$ 0.39	1,084,270	$ 0.39	1,047,963	$ 0.39	4,443,677	$ 0.39
									4,443,677	

MTM Fixed Price Basis Swaps–West Texas Intermediate (WTI)

	For the quarter ended (in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2014	60,928	$ 94.64	57,154	$ 94.67	53,797	$ 94.72	50,597	$ 94.80	222,476	$ 94.70
2015	47,747	$ 90.95	45,065	$ 91.00	42,672	$ 91.04	40,329	$ 91.10	175,813	$ 91.02
2016	17,957	$ 85.50	16,985	$ 85.50	16,048	$ 85.50	15,127	$ 85.50	66,117	$ 85.50
									464,406	

Investing Activities—Acquisitions and Capital Expenditures

Cash provided by investing activities was $22.1 million for the year ended December 31, 2013, compared to $14.8 million of cash used in investing activities for the same period in 2012. In 2013, we sold our Robinson's Bend Field assets in the Black Warrior Basin of Alabama for net proceeds of approximately $59.0 million after customary costs and working capital adjustments and received $0.2 million in distributions from an equity affiliate. Our cash capital expenditures were $35.9 million, consisting of $15.3 million in development expenditures focused on oil completions in the Cherokee Basin, $0.1 million to acquire certain additional natural gas wells in the Cherokee Basin, $20.2 million to acquire oil and natural gas properties in Texas and Louisiana, and $0.4 million in development expenditures focused on the oil and natural gas properties acquired in Texas and Louisiana.

During 2012, our cash capital expenditures were $15.9 million, which primarily consisted of development expenditures for oil drilling and recompletion opportunities in the Cherokee Basin. We also sold 14 wells in the Central Kansas Uplift for $1.4 million and $0.1 million in trucks and equipment. We received approximately $0.2 million in distributions from an equity affiliate.

Our current 2014 capital budget of $20.0 million to $22.0 million is currently expected to be funded using our cash flow from operations. We currently expect to focus our entire 2014 capital budget on higher return oil opportunities and capital efficient recompletion opportunities in our existing asset base in the Mid-Continent and Gulf Coast regions. We currently believe that opportunity set is sufficient to warrant a continuing focus on our oil opportunities with investment of free cash flow at rates of return exceeding 20% over the next few years. We currently believe that natural gas prices in excess of $6.00 per Mcfe are required to produce rates of return that generally support capital spending on drilling new wells that produce only coalbed methane gas.

The amount and timing of our capital expenditures is largely discretionary and within our control. If oil or natural gas prices decline to levels below acceptable levels, and the borrowing base under our reserve-based credit facility is reduced, drilling costs escalate, or our efforts to exploit oil potential in our asset base prove to be unsuccessful, we could choose to defer a portion of these planned capital expenditures until later periods. We routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, availability of funds under our reserve-based credit facility, and internally generated cash flow. These and other matters are outside of our control and could affect the timing of our capital expenditures. Based upon current oil and natural gas price expectations and expected 2014 production levels, we anticipate that our cash flow from operations will meet any planned capital expenditures and other cash requirements for the next twelve months. We also would have access to any existing available borrowing capacity under our reserve-based credit facility and our then existing cash balance if additional funds are needed in the future. Future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that our operations and other capital resources will provide cash in sufficient amounts during 2014 to maintain our planned levels of capital expenditures, to maintain the outstanding debt level under our reserve-based credit facility, or to commence any quarterly distribution to unitholders. Our capital expenditures are also impacted by drilling and service costs. In the event of inflation increasing drilling and service costs, our hedging program will limit our ability to have increased revenues recoup the higher costs, which could further impact our planned capital spending.

Financing Activities

Our net cash used in financing activities was $34.4 million for the year ended December 31, 2013, compared to $14.7 million used in financing activities for the same period in 2012. We used $50.2 million of cash in 2013 to reduce our outstanding balance under our reserve-based credit facility. This debt reduction was funded from a portion of the proceeds from the sale of our Robinson’s Bend Field assets in the Black Warrior Basin of Alabama. We also had borrowings under our reserve-based credit facility of $16.9 million during 2013, which were used as a portion of the purchase price for the properties that we acquired in Texas and Louisiana. During 2012, we used $14.4 million of our existing cash balance to reduce our outstanding debt under our reserve-based credit facility.

At December 31, 2013, we had $50.7 million in outstanding debt and had approximately $0.8 million in debt issue costs remaining to be amortized through March 31, 2014.

We suspended our $0.13 per unit quarterly distributions to unitholders for the quarter ended June 30, 2009, through the year ended December 31, 2013, to reduce our outstanding indebtedness. For additional information on our distribution, refer below to “Outlook.”

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 December 31, 2013, we have not suffered any significant losses with our counterparties as a result of nonperformance.

Certain key counterparty relationships are described below:

Macquarie Energy LLC

Macquarie Energy LLC (Macquarie), a subsidiary of Sydney, Australia-based Macquarie Group Limited, purchases a portion of our natural gas production in the Cherokee Basin. We have received a guarantee from Macquarie Bank Limited for up to $2.0 million in purchases through December 31, 2015 and up to $2.0 million in purchases through January 31, 2016. As of December 31, 2013, we had no past due receivables from Macquarie.

Scissortail Energy, LLC

Scissortail Energy, LLC (Scissortail), a subsidiary of Kinder Morgan Energy Partners, L.P., purchases a portion of our natural gas production in Oklahoma and Kansas. As of December 31, 2013, we had 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 June 30, 2014. As of December 31, 2013, we had no past due receivables from ONEOK.

Derivative Counterparties

As of December 31, 2013, all of our derivatives are with Societe Generale, a lender in our reserve-based credit facility, and The Bank of Nova Scotia. All of our derivatives are currently collateralized by the assets securing our reserve-based credit facility and therefore currently do not require the posting of cash collateral. As of December 31, 2013, each of these financial institutions had an investment grade credit rating. Several of the lenders in our reserve-based credit facility were, as of December 31, 2013, on review for possible ratings downgrade by S&P or Moody's. However, it would take a multiple ratings downgrade for each of these banks to fall below investment grade.

Reserve-Based Credit Facility

As of December 31, 2013, the banks and their percentage commitments in our reserve-based credit facility are: Societe Generale (36.36%), OneWest Bank, FSB (36.36%) and BOKF NA, dba Bank of Oklahoma (27.28%). As of December 31, 2013, each of these financial institutions had an investment grade credit rating.

Outlook

During 2014, we expect that our business will continue to be affected by the factors described in "Item 1A. Risk Factors," as well as the following key industry and economic trends. Our expectation is based upon key assumptions and information currently available to us. To the extent that our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Full Year 2014 Expected Results

Our 2014 business plan and forecast will be focused on prioritizing oil production in the execution of our capital program, actively managing our operating expenses and actively pursuing merger and acquisition opportunities that could lead to enhanced unitholder value. We currently expect our operating environment to be characterized by continued low natural gas prices, stable oil prices and the pressure to reduce operating expenses.

For 2014 we currently anticipate:

•Our production to be in a range of 8.1 Bcfe to 9.3 Bcfe, approximately 89% of which is currently hedged.

•Our operating expenses to be actively managed, resulting in a range of $33.3 million to $37.3 million.

•Our Adjusted EBITDA to be in a range of $26.7 million to $29.9 million.

•Our total capital expenditures to be between $20.0 million to $22.0 million. Our entire capital budget for 2014 will be focused on capital efficient oil drilling and recompletion opportunities in our existing properties.

•At the present time, we are actively pursuing merger and acquisition opportunities that could lead to enhanced unitholder value.

Critical Accounting Policies and Estimates

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

Oil and Natural Gas Properties

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

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

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

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. Cash flow estimates for the impairment testing are based on third party reserve reports and exclude derivative instruments. Refer to Note 7 to our consolidated financial statements for additional information.

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

Oil and Natural Gas Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Management estimates the proved reserves attributable to our ownership based on various factors, including consideration of reserve reports prepared by NSAI, an independent petroleum engineering firm. On an annual basis, our proved reserve estimates and the reserve report prepared by NSAI are reviewed by the audit committee of our board of managers and our board of managers. Our financial statements for 2012 and 2013 were prepared using NSAI’s estimates of our proved reserves.

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

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

Revenue Recognition

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

Gas imbalances occur when sales are more or less than the entitled ownership percentage of total gas production. Any amount received in excess is treated as a liability. If less than the entitled share of the production is received, the excess is recorded as a receivable. There were no material gas imbalance positions at December 31, 2013 and 2012.

Hedging Activities

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

We account for all our open derivatives as mark-to-market activities using the mark-to market accounting method. Using this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions "Risk management assets" and “Risk management liabilities.” We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of operations under the captions “Natural gas sales” and “Oil and liquid sales”, which comprise our total revenues for commodity derivatives. Settled interest rate swaps are recognized as “Interest expense” on our consolidated statement of operations.

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

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

Recent Accounting Pronouncements and Accounting Changes

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board (the FASB), which are adopted by us as of the specified effective date. Unless otherwise discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on our consolidated statements upon adoption.

In December 2011, the FASB issued ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities, which requires additional disclosures for financial and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, regardless of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. In January 2013, the FASB issued ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, an amendment to ASC Topic 210. The update clarifies that the scope of ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities, applies to derivatives accounted for in accordance with ASC Topic 815, Derivatives and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. The guidance was effective beginning on or after January 1, 2013, and primarily impacts the disclosures associated with our commodity and interest rate derivatives. The adoption of this guidance did not have any impact on our consolidated financial position, results of operations or cash flows.

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

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

This section is not applicable to smaller reporting companies.

Item 8. Financial Statements and Supplementary Data

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

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

In March 2013, our audit committee approved the appointment of KPMG LLP (KPMG) as our independent registered public accounting firm for the fiscal year ending December 31, 2013, and approved the dismissal of PricewaterhouseCoopers LLP (PwC) as our auditors. We formally notified PwC of their dismissal on March 18, 2013.

During our fiscal year ended December 31, 2012, PwC’s report on our financial statements did not contain an adverse opinion or disclaimer of opinion, and was not qualified or modified as to uncertainty, audit scope or accounting principles.

We and PwC have not, during our fiscal year ended December 31, 2012 and the subsequent period through March 18, 2013, had any disagreements on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedure which disagreement, if not resolved to the satisfaction of PwC, would have caused PwC to make reference to the matter in its reports on our financial statements for such years; and there were no “reportable events” as the term is described in Item 304(a)(1)(v) of Regulation S-K.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer (CEO) and the Chief Financial Officer (CFO) 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 December 31, 2013 (the Evaluation Date). Based on such evaluation, the CEO and the CFO have concluded that, as of the Evaluation Date, our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and is accumulated and communicated to our management, including our CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

During the three months ended December 31, 2013, 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 January 2013, we terminated our support services agreement with Schlumberger, ePrime Services. Through this outsource agreement, Schlumberger managed the cash flow associated with our interest in our oil and natural gas properties, including the payment of invoices, calculation and payment of royalties, and receipt of revenues from oil and natural gas sales, and provided accounting information used to generate financial statements. Beginning in 2013, these functions are handled by our internal accounting department in Houston, Texas, utilizing the same oil and natural gas computer software Schlumberger used. Additional experienced staffing has been hired, primarily in the revenue accounting function.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) provides smaller reporting companies 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 years ended December 31, 2013, and 2012. 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 use of this exemption was reviewed and approved by our audit committee.

Reports 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.

The audit committee of our board of managers, which consists of three independent managers, meets periodically with management, our internal auditor and KPMG to review the activities of each in discharging their responsibilities. Our internal auditor and KPMG 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, 2013.

Item 9B. Other Information

None.

PART III

Item 10. Managers, Executive Officers and Corporate Governance

The following table shows information for members of our board of managers and our executive officers as of March 14, 2014. Members of our board of managers are elected for one–year terms, and our executive officers will hold office at the discretion of, and may be removed by, our board of managers.

Name	Age	Position with Constellation Energy Partners LLC
Richard H. Bachmann	61	Independent manager
Stephen R. Brunner	56	Chief Executive Officer, Chief Operating Officer and President
Elizabeth A. Crawford	47	Vice President of Land, General Counsel and Corporate Secretary

Richard S. Langdon	63	Independent manager
Antonio R. Sanchez, III	40	Manager
John N. Seitz	62	Independent manager
Charles C. Ward	53	Chief Financial Officer and Treasurer
Gerald F. Willinger	46	Manager

Richard H. Bachmann has been an independent member of our board of managers and our audit, compensation, conflicts, and nominating and governance committees and chair of our conflicts committee since November 2006. Mr. Bachmann joined the general partner (the General Partner) of Enterprise Products Partners L.P. (Enterprise) and Enterprise Products Company, a privately-held affiliate of Enterprise, as Executive Vice President, Chief Legal Officer and Secretary in January 1999. Mr. Bachmann resigned such positions in November 2010. Also since January 1999, Mr. Bachmann has served as a Director of Enterprise Products Company. He previously served as a Director of the General Partner from June 2000 to January 2004 and was re-elected and continued as a Director of the General Partner from February 2006 until April 2010. Mr. Bachmann was elected Group Vice Chairman, Chief Legal Officer and Secretary of Enterprise Products Company in December 2007. Since April 2010, Mr. Bachmann has been and continues as the President and Chief Executive Officer of Enterprise Products Company. From August 2005 until April 2010, Mr. Bachmann served as Executive Vice President, Chief Legal Officer and Secretary of EPE Holdings LLC, the sole general partner of Enterprise GP Holdings L.P., a publicly-traded partnership and an affiliate of Enterprise. Mr. Bachmann was also elected a Director of EPE Holdings in February 2006. In April 2010, Mr. Bachmann resigned his positions as Chief Legal Officer and Secretary of EPE Holdings LLC, but remained as a director and an Executive Vice President of that company until its merger with and into a subsidiary of Enterprise. After the merger in November 2010, Mr. Bachmann was elected a director of the post-merger general partner of Enterprise. In October 2006, Mr. Bachmann was elected President, Chief Executive Officer and a Director of DEP Holdings LLC, the sole general partner of Duncan Energy Partners L.P., a publicly-traded partnership, but resigned those positions in April 2010 to devote more time to his position at Enterprise Products Company. All of the foregoing entities perform various transportation and other services to the energy and petrochemical industries. Prior to joining Enterprise Products Company in 1999, Mr. Bachmann served as a Partner in the law firms of Snell & Smith P.C. from 1993 to 1998 and Butler & Binion from 1988 to 1993.

Stephen R. Brunner has served as our President and Chief Executive Officer since March 2008 and our Chief Operating Officer since February 2008. He has also served as a member of our board of managers from December 2008 until August 2011. Mr. Brunner also served as Vice President for Constellation Energy Commodities Group, Inc. (CCG) from February 2008 to January 2009. From 2001 until November 2007, Mr. Brunner served as Executive Vice President, Operations of Pogo Producing Company, an oil and gas exploration company.

Elizabeth A. Crawford has served as our Vice President of Land, General Counsel and Corporate Secretary since February 2013. Since joining the Company in October 2009, she has held various positions, including most recently as Associate General Counsel and Land Manager. Prior to that time, she served as a Senior Counsel for CCG from August 2005 until June 2009. Prior to joining CCG, she held various legal positions at Anadarko Petroleum Corporation and El Paso Corporation.

Richard S. Langdon has been an independent member of our board of managers and our audit, compensation, conflicts and nominating and governance committees and chair of our audit committee since November 2006 and has served as the chairman of our board of managers since October 2011. Mr. Langdon is also currently the President, Chief Executive Officer and Chairman of KMD Operating Company LLC (KMD Operating), a position held since November 2011, a privately held exploration and production company. Mr. Langdon has been serving as the Interim President and Chief Executive Officer of Gasco Energy, Inc., a publicly traded exploration and production company, since May 2013. Mr. Langdon has also served as a Director of Gasco Energy, Inc. since 2003. Mr. Langdon was the President and Chief Executive Officer of Matris Exploration Company L.P., a privately held exploration and production company (Matris Exploration), from July 2004 and Executive Vice President and Chief Operating Officer of KMD Operating from August 2009 until the merger of Matris Exploration into KMD Operating in November 2011, which merger was effective January 2011. Mr. Langdon also served as President and Chief Executive Officer of Sigma Energy Ventures, LLC, a privately held exploration and production company, from November 2007 until November 2013. From 1997 until 2002, Mr. Langdon served as Executive Vice President and Chief Financial Officer of EEX Corporation, a publicly traded exploration and production company that merged with Newfield Exploration Company in 2002. Prior to that, he held various positions with the Pennzoil Companies from 1991 to 1996, including Executive Vice President—International Marketing—Pennzoil Products Company; Senior Vice President—Business Development—Pennzoil Company; and Senior Vice President—Commercial & Control—Pennzoil Exploration & Production Company.

Antonio R. Sanchez, III has been a member of our board of managers since August 2013. Mr. Sanchez has served as the President and Chief Executive Officer of Sanchez Energy Corporation (NYSE: SN) and has been a member of SN's board of directors since its formation in August 2011. He has been directly involved in the oil and gas industry for over 12 years. Mr. Sanchez, III is also the President of Sanchez Oil & Gas Corporation, which he joined in October 2001, as well as the President of SEP Management I, LLC and a Managing Director of Sanchez Energy Partners I, LP. In his capacities as a director and officer of these companies, Mr. Sanchez, III manages all aspects of their daily operations, including exploration, production, finance, capital markets activities, engineering and land management. From 1997 to 1999, Mr. Sanchez, III was an investment banker specializing in mergers and acquisitions with J.P. Morgan Securities Inc. From 1999 to 2001, Mr. Sanchez, III worked in a variety of positions, including sales and marketing, product development and investor relations, at Zix Corporation, a publicly traded encryption technology (NASDAQ: ZIXI). Mr. Sanchez, III has also been a member of the board of directors of Zix Corporation since May 2003.

John N. Seitz has been an independent member of our board of managers and our audit, compensation, conflicts, and nominating and governance committees and chair of our compensation and nominating and governance committees since November 2006. Mr. Seitz currently serves as Chairman and Chief Executive Officer of GulfSlope Energy, Inc. (OTCQB: GSPE), an independent energy company focused on exploration for crude oil and natural gas in the Gulf of Mexico. Mr. Seitz is also currently Vice Chairman of the Board of Directors of Endeavour International Corporation, a publicly traded oil and gas exploration and production company which he founded in February 2004. Prior to founding Endeavour International Corporation, Mr. Seitz served as Chief Executive Officer, President and Chief Operating Officer of Anadarko Petroleum Corporation from January 2002 to March 2003, and prior to being named Chief Executive Officer, President and Chief Operating Officer, Mr. Seitz was the Chief Operating Officer and President of Anadarko Petroleum Corporation beginning in 1999. Mr. Seitz also served as Anadarko Petroleum Corporation's Executive Vice President, Exploration and Production and as a member of its Board of Directors from 1997 to 1999. Mr. Seitz also serves as a Director for ION Geophysical Corporation, f/k/a Input Output, Inc., a publicly traded provider of seismic products and services, and as a Director of Gulf United Energy, Inc., a publicly traded energy company with interests in international oil and natural gas properties.

Charles C. Ward has served as our Chief Financial Officer and Treasurer since March 2008. Mr. Ward also served as a Vice President of CCG from November 2005 until December 2008. Prior to that time, he was a Vice President of Enron North America Corp. from March 2002 to November 2005.

Gerald F. Willinger has been a member of our board of managers since August 2013. Mr. Willinger is currently a Managing Partner of Sanchez Capital Advisors, LLC and Manager and Co-founder of Sanchez Resources, LLC, an oil and gas company since February 2010. Mr. Willinger currently serves as a Director of Sanchez Resources. From 1998 to 2000, Mr. Willinger was an investment banker with Goldman, Sachs & Co. Mr. Willinger served in various private equity investment management roles at MidOcean Partners, LLC and its predecessor entity, DB Capital Partners, LLC, from 2000 to 2003 and at the Cypress Group, LLC from 2003 to 2006. Prior to joining Sanchez Capital Advisors, LLC, Mr. Willinger was a Senior Analyst for Silver Point Capital, LLC, a credit-opportunity fund, from 2006 to 2009.

Qualifications of Board of Managers

The holders of our Class A units elect two Class A managers and our Class B unitholders elect three Class B managers to our board of managers. Some of the key criteria for serving on our board of managers as a Class B manager include independence from PostRock, SOG and Exelon, experience in the exploration and production industry, familiarity with master limited partnerships, and corporate governance, financial, or other management experience. Our Class B managers, and the specific experience, qualifications, attributes and skills that led the board to conclude that they should serve as managers, are:

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

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

•Mr. Seitz brings to our board significant managerial and operational experience in the oil and gas industry. He is the current Chairman and Chief Executive Officer of GulfSlope Energy, Inc., an independent energy company focused on exploration for crude oil and natural gas in the Gulf of Mexico. He is the current vice chairman of Endeavor International Corporation, a publicly traded oil and gas exploration company, and has served as the Chief Executive Officer of Anadarko Petroleum, one of the largest independent oil and gas companies in North America. His specialized technical experience in the oil and gas industry adds significant value to the board's contribution to our performance. He also has prior public company board experience, which is beneficial for the operations of our board, and currently serves as a director of ION Geophysical Corporation, a publicly traded provider of seismic services to the exploration and production industry, and as a director of Gulf United Energy, Inc., a publicly traded independent energy company with interests in international oil and natural gas properties. Mr. Seitz is independent of PostRock, SOG and Exelon.

Our Class A unitholders have elected Messrs. Sanchez and Willinger as our two Class A managers to represent the Class A unitholder interests on our board. Our Class A managers, and the specific experience, qualifications, attributes and skills that led the Class A unitholders to conclude that they should serve as managers, are:

•Mr. Sanchez, III brings to our board substantial upstream oil and gas/energy industry experience in both public and private entities. In his current capacity as President and Chief Executive Office of Sanchez Energy Corporation, he brings the perspective of leading a quickly growing, publicly traded upstream company focused on asset value maximization and the creation of shareholder value. In his current capacity as President of Sanchez Oil & Gas Corporation, he brings particular expertise in operating multiple upstream oil and gas entities through a shared service model. He acts as a liaison with Sanchez Energy Partners I, LP and ensures our board has a continuing dialogue with our significant unitholder.

•Mr. Willinger brings to our board substantial experience in risk management, finance and negotiated transactions in the energy industry. He has a valuable perspective on upstream master limited partnerships, which provides our board with unique insights in to master limited partnership management and growth opportunities. Additionally, he brings an expansive network of both private and public capital providers, which is useful for our board when evaluating possible capital sources. Mr. Willinger also acts as a liaison between the Company and Sanchez Energy Partners I, LP.

Since our initial public offering, all of our Class B managers have been re-elected by our unitholders. Our Class A unitholders currently elect their Class A managers concurrent with our annual meeting.

Corporate Governance

Board Leadership Structure and Risk Oversight

Our board has three independent members as Class B managers and two managers elected by our Class A unitholders. Our independent board members are currently serving or have served as members of senior management of other public companies and have served as managers or directors of other public companies. We have four board committees comprised solely of independent managers, with each of these committees having an independent manager serving as chair of the committee. We believe that the number of independent, experienced managers that make up our board benefits our Company and our unitholders.

Under our operating agreement and corporate governance guidelines, the chairman of the board is responsible for:

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

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

- presiding at all board meetings where the chairman of the board of managers is not present;
- serving as a liaison between the chairman of the board of managers and the independent managers;
- approving information sent to the board and agendas and meeting schedules for board meetings;
- calling meetings of the non-management managers;
- ensuring his availability for direct consultation upon request of a major unitholder;
- chairing the executive session of non-management managers; and
- serving as a contact for unitholder complaints, other than those involving auditing/accounting matters.

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

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

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

During 2012 and 2013, the board of managers met 11 and eight times, respectively. Each Class B manager attended at least 75% of the meetings of the board and of each committee on which he served.

The board of managers has adopted a policy that encourages each manager to attend the annual meeting of unitholders. All of the persons then serving as our managers attended the 2012 annual meeting of unitholders.

Committees of the Board of Managers

Audit Committee

As described in the audit committee charter, the audit committee is directly responsible for the appointment, compensation, retention and oversight of the work of the independent public accountants to audit our financial statements, including assessing the independent auditor's qualifications and independence, and establishes the scope of, and oversees, the annual audit. The committee also approves any other services provided by public accounting firms. The board has delegated to the audit committee the review and approval of our decision to enter into derivative transactions and our exemption from the swap clearing and swap execution requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act). The audit committee provides assistance to the board in fulfilling its oversight responsibility to the unitholders, the investment community and others relating to the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor's qualifications and independence and the performance of our internal audit function. The audit committee oversees our system of disclosure controls and procedures and system of internal controls regarding financial, accounting, legal compliance and ethics that management and our board of managers established. In doing so, it will be the responsibility of the audit committee to maintain free and open communication between the committee and our independent auditors, the internal accounting function and management of our Company.

The board of managers has determined that the chairman of the audit committee is an "audit committee financial expert" as that term is defined in the applicable rules of the SEC.

The audit committee held six meetings in 2012 and four meetings in 2013. Mr. Langdon is chairman, and Messrs. Seitz and Bachmann are members.

Compensation Committee

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

The committee establishes and reviews general policies related to our compensation and benefits, and annually reviews and approves the compensation paid to our executive officers and non-employee managers. The committee also approves the annual performance-based bonus award pool and long-term incentive equity awards for all employees.

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

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

Our compensation committee is authorized to retain compensation consultants at the Company's expense and obtain any compensation surveys or reports regarding the design and implementation of compensation programs that it may find necessary in designing, implementing or administering compensation programs. During 2012 and 2013, the committee retained Meridian Compensation Partners, LLC (Meridian). The committee retained Meridian after a review of the independence factors included in the Dodd-Frank Act for compensation consultants and considering Meridian's independence based on such factors. The amount paid to Meridian was less than $50,000 in 2012 and less than $37,000 in 2013, for which Meridian prepared a competitive review of the compensation of our executive officers, advised the compensation committee regarding the design of our incentive plans and assisted with other related matters.

The compensation committee held nine meetings in 2012 and five meetings in 2013. Mr. Seitz is chairman, and Messrs. Bachmann and Langdon are members.

Conflicts Committee

Our board of managers has established a conflicts committee to review specific matters that the board believes may involve conflicts of interest, including transactions with related persons such as PostRock, SOG, Exelon or their affiliates or our managers and executive officers. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to our Company. Our operating agreement provides that members of the conflicts committee may not be officers or employees of our

Company, or directors, officers or employees of any of our affiliates, and must meet the independence standards for service on an audit committee of a board of directors as established by NYSE MKT and SEC rules. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to our Company and approved by all of our unitholders. However, the board is not required by the terms of our operating agreement to submit the resolution of a potential conflict of interest to the conflicts committee, and may itself resolve such conflict of interest if the board determines that (i) the terms of the related person transaction are no less favorable to us than those generally being provided to or available from unrelated third parties or (ii) the transaction is fair and reasonable to us, taking into account the totality of the relationships between the parties involved. Any matters approved by the board in this manner will be deemed approved by all of our unitholders.

The conflicts committee held two meetings in 2012 and two meetings in 2013. Mr. Bachmann is chairman, and Messrs. Seitz and Langdon are members.

Nominating and Governance Committee

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

The nominating and governance committee held four meetings in 2012 and five meetings in 2013. Mr. Seitz is chairman, and Messrs. Bachmann and Langdon are members.

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

Nominations for Manager

The board of managers seeks diverse candidates who possess the background, skills and expertise to make a significant contribution to the board of managers, us and our unitholders. Annually, the nominating and corporate governance committee reviews the qualifications and backgrounds of the managers, as well as the overall composition of the board of managers, and recommends to the full board of managers the slate of Class B manager candidates to be nominated for election at the next annual meeting of unitholders. The board of managers has adopted a policy whereby the nominating and corporate governance committee will consider the recommendations of unitholders with respect to candidates for election to the board of managers and the process and criteria for such candidates will be the same as those currently used by us for manager candidates recommended by the board of managers or management. During 2013, there were no changes to the procedures for nominating candidates to our board of managers.

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

•has the business and/or professional knowledge and experience applicable to us, our business and the goals and perspectives of our unitholders;

•is well-regarded in the community, with a long-term, good reputation for highest ethical standards;

•has good common sense and judgment;

•has a positive record of accomplishment in present and prior positions;

•has an excellent reputation for preparation, attendance, participation, interest and initiative on other boards on which he or she may serve; and

•has the time, energy, interest and willingness to become involved with us and our future.

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

A unitholder who wishes to recommend to the nominating and corporate governance committee a nominee for manager for the 2014 annual meeting of unitholders should submit the recommendation in writing to the Secretary, Constellation Energy Partners LLC, 1801 Main Street, Suite 1300, Houston, Texas 77002 so it is received by July 28, 2014 but not earlier than June 28, 2014.

Section 16(a) Beneficial Ownership Reporting Compliance

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

Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and managers, we believe that during 2012 and 2013 all Section 16(a) reporting persons complied with all applicable filing requirements in a timely manner.

Certifications

The NYSE MKT requires the Chief Executive Officer of each listed company to certify annually that he is not aware of any violation by the Company of the NYSE MKT’s corporate governance listing standards, qualifying the certification to the extent necessary. In accordance with the rules of the NYSE MKT, we will provide such a certification within 30 days after our 2013 annual meeting to be held in 2014. As a result of the PostRock litigation, we were enjoined from holding our 2013 annual meeting by the Court of Chancery of the State of Delaware (the Court); therefore, our 2013 certification with NYSE MKT has not been filed. Once the court allows us to conduct our 2013 annual meeting, it will be scheduled and held, with the certification being filed with NYSE MKT within 30 days of the meeting. The certifications of our Chief Executive Officer and Chief Financial Officer required by Sections 302 and 906 of the Sarbanes-Oxley Act have been included as exhibits to our Annual Report on Form 10-K which was filed on March 27, 2014.

Item 11. Executive Compensation

Summary Compensation Table

The following table sets forth the compensation of our named executive officers (NEOs) for 2013 and 2012:

Name and Principal Position	Year	Salary	Cash Bonus(a)	Unit Awards(b)	All Other Compensation(c)	Total
Stephen R. Brunner	2013	$ 339,900	$ 169,950	$—	$ 8,842	$ 518,692
Chief Executive Officer, Chief Operating Officer, and President(d)	2012	$ 339,900	$ 169,950	$ 169,201	$ 273,637	$ 952,688
Elizabeth A. Crawford	2013	$ 210,000	$ 57,750	$—	$ 10,096	$ 277,846
Vice President of Land, General Counsel and Corporate Secretary(d) (e)						
Michael B. Hiney	2013	$ 91,512	$—	$—	$ 267,216	$ 358,728
Chief Accounting Officer and Controller(d) (e)	2012	$ 198,275	$ 54,526	$ 33,841	$ 61,145	$ 347,787
Lisa J. Mellencamp	2013	$ 21,788	$—	$—	$ 751,502	$ 773,290
General Counsel and Secretary(e) (e)	2012	$ 226,600	$—	$ 67,681	$ 115,905	$ 410,186
Charles C. Ward	2013	$ 254,925	$ 95,597	$—	$ 13,722	$ 364,244
Chief Financial Officer and Treasurer(d) (e)	2012	$ 254,925	$ 95,597	$ 84,602	$ 143,187	$ 578,311

(a)The amount in this column reflects each named applicable named executive officer's annual cash incentive bonus earned for 2013 and 2012 performance, as applicable. The annual cash incentive bonuses were determined by our compensation committee based on assessments of both Company and individual performance. The amounts for each of Messrs. Brunner, Hiney, and Ward and Ms. Mellencamp were awarded in recognition of the achievement of overall performance at below target level in 2012. The amounts for each of Messrs. Bruner and Ward and Ms. Crawford were awarded in recognition of the achievement of overall performance at below target level in 2013.

(b)The amount in this column reflects the grant date fair value of all unit awards in 2012 calculated in accordance with FASB ASC Topic 718. These unit awards vest between 2013 and 2015. See Part IV. "Exhibits and Financial Statement Schedules — Notes to Consolidated Financial Statements — 11. Unit-Based Compensation" of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2012 for further information. There were no unit awards granted in 2013.

(c)The amount in this column reflects the vested amount of the cash portion of the cash-based performance award earned during 2012, the amount of matching contributions made to each named executive officer under our 401k plan, the cost of life insurance equal to the named executive officer's salary for 2013, 2012 and 2011, the one-time inducement sign-on bonus during 2011, and severance payments and other amounts due Mr. Hiney and Ms. Mellencamp as a result of their employment termination in 2013. The 2012 cash-based performance award for Messrs. Brunner, Ward and Hiney and Ms. Mellencamp was $250,000, $125,000, $50,000, and $100,000, respectively. The cash portion of the one-time inducement sign-on bonus for Messrs. Brunner, Ward and Hiney and Ms. Mellencamp was $225,000, $168,750, $131,250, and $150,000, respectively. The amount due to Mr. Hiney as a result of employment termination in 2013 was $261,096, of which $200,000 was a severance amount. The amount due to Ms. Mellencamp as a result of employment termination in 2013 was $750,713, of which $639,900 was a severance amount.

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

(e)Mr. Hiney's employment with the Company terminated in May 2013, and Ms. Mellencamp's employment with the Company terminated in January 2013. Ms. Crawford was promoted to an executive officer position in February 2013. Mr. Ward became the Principal Accounting Officer upon Mr. Hiney's departure in May 2013.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth the outstanding equity awards and their market value using the closing price of our common units on NYSE MKT at December 31, 2013 for our 2013 NEOs:

	Outstanding Equity Awards at December 31, 2013			
Name	Number of Restricted Units Not Vested	Number of Unit-Based Awards Not Vested	Fair Market Value of Units Not Vested	Vesting Dates
Stephen R. Brunner	136,042	-	$ 326,501	2014
	46,717	-	112,121	2015
	182,759	-	$ 438,622	
Elizabeth A. Crawford	5,980	-	$ 14,352	2014
	1,558	-	3,739	2015
	7,538	-	$ 18,091	
Charles C. Ward	49,070	-	$ 117,768	2014
	15,575	-	37,380	2015
	64,645	-	$ 155,148	

Employment Agreements

Pursuant to the terms of the employment agreements, each 2013 NEO received the following compensation with respect to performance for 2013:

Name	Base Salary	Bonus Target	Maximum Bonus
Stephen R. Brunner	$ 339,900	100%	200%
Elizabeth A. Crawford	$ 210,000	55%	80%
Charles C. Ward	$ 254,925	75%	150%

Termination of Employment

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

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

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

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

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

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

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

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

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

A “Change of Control” occurs if any of the following events occurs: (i) during a period of 24 consecutive months, all of the Class B managers at the beginning of such period, and any persons nominated by at least two such managers, cease to constitute all of the Class B managers, (ii) during a period of 24 consecutive months, the individuals who constitute our board of managers at the beginning of such period, and any persons nominated by at least two Class B managers, cease to constitute at least a majority of our board of managers, (iii) during a period of 24 consecutive months immediately following a Class A Event (described below), at least one Class B manager ceases to serve as a manager, (iv) any person becomes the beneficial owner of 25% or more of the combined voting power of our outstanding units eligible to vote for the election of our board of managers, (v) certain business combinations, unless the Company’s unitholders control more than 60% of the voting power of the surviving entity, no person owns more than 25% of the voting power of the surviving entity and a majority of the members of the board of the surviving entity were managers at the time the agreement approving the business combination was approved by our board of managers, (vi) a plan of liquidation of the Company is approved by the unitholders or (vii) a sale of all or substantially all of the assets of the Company to an acquiror which has more than 40% of its voting power controlled by persons other than the Company’s unitholders. A “Class A Event” occurs if (A) PostRock ceases to own directly or indirectly at least 50% of the Class A units, (B) certain business combinations involving PostRock where persons other than PostRock’s stockholders control more than 40% of the voting power of the surviving entity or (C) PostRock ceases to have the direct or indirect right to appoint all of the Class A managers. The employment agreements stipulate that a Class A Event occurred on March 12, 2012, and the issuance of Class A units on August 9, 2013 to Sanchez Energy Partners I, LP triggered another Class A Event. Accordingly, a Change of Control will be triggered upon the anticipated election of two new class B members at the 2013 annual meeting.

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

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

The initial term of the employment agreements will expire in 2014 unless sooner terminated in accordance with the employment agreement. If the agreements have not otherwise been terminated prior to the expiration of the initial term, the employment agreements will automatically be extended for an additional one-year period unless either party to such employment agreement delivers written notice 180 days prior to the expiration of the initial term. We guaranteed the obligations of CEP Services Company, Inc. under the employment agreements.

Compensation of Managers

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

•$40,000 annual retainer for each manager;

•the chairman of the board of managers will receive a $50,000 annual retainer and the chairman of the audit committee will receive a $10,000 annual retainer;

•$2,500 fee for each meeting of the board of managers and each committee meeting attended by a member thereof that occurs on a day when there is no board meeting; and

•reasonable travel expenses to attend meetings.

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

•Each non-employee manager will receive an annual restricted common unit award with a value of $75,000, to be granted as of March 1 of each year, such award to have a one-year vesting period and to be forfeited on a pro-rata basis if service as a manager terminates prior to the one-year vesting period. The managers may also elect to pay this award in cash as opposed to granting restricted common units.

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

For 2012, due to the limited number of units remaining under our Long-Term Incentive Plan and our 2009 Omnibus Incentive Compensation Plan and in order to reduce the structural general and administrative expenses of the Company, the managers elected to not be paid the $75,000 in restricted common units or in cash on March 1, 2013.

The following table sets forth a summary of the 2013 non-employee manager compensation, as determined by our board of managers:

Manager Compensation

Name	Fees Earned or Paid in Cash	Unit Awards(a)	All Other Compensation(a)	Total
Richard H. Bachmann	$ 45,000	$—	$—	$ 45,000
John R. Collins(b)	$ 36,848	$—	$—	$ 36,848
Richard S. Langdon	$ 90,000	$—	$—	$ 90,000
Gary M. Pitman(b)	$ 36,848	$—	$—	$ 36,848
Antonio R. Sanchez, III(c)	$ 8,261	$—	$—	$ 8,261
John N. Seitz	$ 45,000	$—	$—	$ 45,000
Gerald F. Willinger(c)	$ 8,261	$—	$—	$ 8,261

(a)No annual restricted common unit award (or cash equivalent) of $75,000 was granted for 2013.

(b)Mr. Pittman joined the board of managers effective August 30, 2012 and was removed on August 9, 2013. Mr. Collins was removed from the board of managers on August 9, 2013.

(c)Messrs. Sanchez and Willinger joined the board of managers effective August 30, 2013.

Compensation Committee Interlocks and Insider Participation

During 2013, none of our named executive officers served as a member of the board of directors or compensation committee of any entity that had one or more of its named executive officers serving as a member of our board of managers or compensation committee.

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

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

•each unitholder who is a beneficial owner of more than 5% of our outstanding units;

•each of our managers and 2013 named executive officers; and

•our managers and executive officers as a group.

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

Percentage of total units beneficially owned is based on 28,462,185 common units and 1,615,017 Class A units outstanding. Except as indicated by footnote, to our knowledge the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable. Unless otherwise set forth below, the address of all of all beneficial owners is c/o Constellation Energy Partners LLC, 1801 Main Street, Houston, Texas 77002. Ownership amounts are as of December 31, 2013.

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Name of Beneficial Owner	Common Units Beneficially Owned		Class A Units Beneficially Owned		Percentage of Total Units Beneficially Owned
	Number	Percentage	Number	Percentage	Percentage
PostRock Energy Corporation(1)	5,918,894	20.8%	484,505	30%	21.3%
Sanchez Energy Partners I, LP(2)	4,724,407	16.6%	1,130,512	70%	19.5%
Bradley Louis Radoff(3)	2,360,000	8.3%	—	—	7.8%
Richard H. Bachmann	60,612	*	—	—	*
Stephen R. Brunner	738,007	2.6%	—	—	2.5%
Elizabeth A. Crawford	19,495	*	—	—	*
Michael B. Hiney(4)	95,251	*	—	—	*
Richard S. Langdon	40,100	*	—	—	*
Lisa J. Mellencamp(4)	193,975	*	—	—	*
Antonio R. Sanchez, III(2)	4,724,407	16.6%	1,130,512	70%	19.5%
John N. Seitz	51,612	*	—	—	*
Charles C. Ward	328,722	1.2%	—	—	1.1%
Gerald F. Willinger	—	—	—	—	—
All managers and executive officers as a group (8 persons)	1,238,548	4.4%	—	—	4.1%

*Less than 1%

(1)Ownership data as reported on Schedule 13D/A filed on July 29, 2013, by PostRock Energy Corporation, White Deer Energy L.P., White Deer Energy TE L.P., White Deer Energy FI L.P., Edelman & Guill Energy L.P., Edelman & Guill Energy Ltd., Thomas J. Edelman, and Ben A. Guill. PostRock Energy Corporation, through its direct ownership of CEPM may be deemed to beneficially own the Class B common units and Class A units held by CEPM. The address of PostRock Energy Corporation and CEPM is 210 Park Avenue, Oklahoma City, Oklahoma 73102. The address of the other entities reported is White Deer Energy L.P., 667 Madison Avenue, 4th Floor, New York, New York 10065.

(2)Ownership data as reported on Form 3 on August 13, 2013 and Schedule 13D on August 19, 2013 by Sanchez Energy Partners I, LP, SEP Management I, LLC, Sanchez Oil & Gas Corporation, A. R. Sanchez, Jr. and Antonio R. Sanchez, III. These securities are owned directly by Sanchez Energy Partners I, LP., which is controlled by its general partner, SEP Management I, LLC, a wholly-owned subsidiary of Sanchez Oil & Gas Corporation. Sanchez Oil & Gas Corporation is managed by A.R. Sanchez, Jr. and Antonio R. Sanchez, III. Each of SEP Management I, LLC, Sanchez Oil & Gas Corporation, A. R. Sanchez, Jr. and Antonio R. Sanchez, III may be deemed to share voting and dispositive power over the units held by Sanchez Energy Partners I, LP. Each of SEP Management I, LLC, Sanchez Oil & Gas Corporation, A. R. Sanchez, Jr. and Antonio R. Sanchez, III disclaims beneficial ownership of these securities except to the extent of such person’s pecuniary interest therein.

(3)Ownership data as reported on Schedule 13G/A filed on February 14, 2014 by Bradley Louis Radoff. The address of Mr. Radoff is 1177 West Loop South, Suite 1625, Houston, Texas 77027. The filing lists 2,360,000 Class B common units owned by Mr. Radoff, who has sole voting power.

(4)Ms. Mellencamp resigned as an executive officer in January 2013, and Mr. Hiney resigned as an executive officer in May 2013.

Equity Compensation Plan Information

The following table reflects our equity compensation plan information for our Long-Term Incentive Plan and our 2009 Omnibus Incentive Compensation Plan as of December 31, 2013:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders(a)	—	$—	386,600
Equity compensation plans not approved by security holders	—	$—	—
Total	—	$—	386,600

(a)As of April 15, 2013, the number of securities remaining available for future issuance under our Long-Term Incentive Plan was 102,398 and the number remaining available under our 2009 Omnibus Incentive Plan was 281,252.

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

PostRock, Exelon and SOG, through subsidiaries, own a number of our units. As of December 31, 2013, CEPM, a subsidiary of PostRock, owned 484,505 of our Class A units and 5,918,894 of our Class B common units. CEPH, a subsidiary of Exelon, owned all of our Class C management incentive interests and all of our Class D interests. SEP I, a subsidiary of SOG, owned 1,130,512 of our Class A units, 4,724,407 of our Class B common units and one Class Z unit.

As discussed in "Item 10. Managers, Executive Officers and Corporate Governance-Corporate Governance-Committees of the Board of Managers—Conflicts Committee", either our board of managers or the board's conflicts committee reviews all related person transactions.

Our board of managers has established a conflicts committee to review specific matters that the board believes may involve conflicts of interest, including transactions with related persons such as PostRock, Exelon and SOG or their affiliates, including CEPM, CEPH and SEP I. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to our Company. Our operating agreement provides that members of the conflicts committee may not be officers or employees of our Company, or directors, officers or employees of any of our affiliates, and must meet the independence standards for service on an audit committee of a board of directors as established by NYSE MKT and SEC rules. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to our Company and approved by all of our unitholders. Our board is not required by the terms of our operating agreement to submit the resolution of a potential conflict of interest to the conflicts committee, and may itself resolve such conflict of interest if the board determines that (i) the terms of the related person transaction are no less favorable to us than those generally being provided to or available from unrelated third parties or (ii) the transaction is fair and reasonable to us, taking into account the totality of the relationships between the parties involved. Any matters approved by the board in this manner will be deemed approved by all of our unitholders. For 2012 and 2013, there were no related party transactions with PostRock, Exelon and SOG or their affiliates that were reviewed or required to be reviewed by the conflicts committee.

PostRock as an "Interested Unitholder"

In 2011, PostRock acquired certain of our Class A units and Class B common units in two separate transactions which represented a 21.3% ownership interest in us at December 31, 2013. Approval of the purchase of these units was neither required nor given by our board of managers or conflicts committee. We believe PostRock is now an "interested unitholder" under Section 203 of the Delaware General Corporation Law, which is applicable to us pursuant to our operating agreement. Section 203, as it applies to us, prohibits an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in business combinations with us for three years following the time such person becomes an interested unitholder without the approval of our board of managers and the vote of 66 % of our outstanding Class B common units, excluding those held by the interested unitholder. Section 203 broadly defines "business combination" to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. In addition to limiting our ability to enter into transactions with PostRock or its affiliates, this provision of our operating 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. We believe the Section 203 restrictions related to these unit purchases expire in December 2014.

SOG

In August 2013, SOG acquired certain of our Class A units and Class B common units and one Class Z unit in one transaction which represented a 19.5% ownership interest in us at December 31, 2013. These units were issued to

SOG, along with cash, in exchange for oil and natural gas properties located in Texas and Louisiana.

In August 2013, the Company also entered into a Registration Rights Agreement with SOG pursuant to which the Company granted to SOG certain registration rights related to the unit consideration thereunder. Under the Registration Rights Agreement, the Company granted SOG demand registration rights with respect to the preparation and filing with the SEC of one or more registration statements for the purpose of registering the resale of the securities that will be registered.

Board Independence

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

•the manager has been an employee (other than as an interim executive officer for less than one year), or an immediate family member of the manager has been an executive officer, of us at any time during the past three years:

•the manager has received, or an immediate family member of the manager has received, more than $120,000 in any twelve-month period in direct compensation from us, other than manager and committee fees or other forms of deferred compensation for priors service (provided such compensation is not contingent in any way on continued service), at any time during the past three years;

•the manager has been a partner of or employed by, or an immediate family member of the manager has been a partner of or employed by, our internal or external auditor at any time during the past three years;

•the manager has been employed, or an immediate family member of the manager has been employed, as an executive officer of another company where any of our present executives serve on that company's compensation committee at any time during the past three years; or

•the manager has been an executive officer or an employee, or an immediate family member of the manager has been an executive officer, of a company that makes payments to, or receives payments from us for property or services in an amount that, in any single fiscal year, exceeds the greater of $200,000, or 5% of such other company's consolidated gross revenues, at any time during the past three years.

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

The board of managers has determined that each of Messrs. Bachmann, Langdon and Seitz is independent under the NYSE MKT listing standards. In addition, the audit, compensation and nominating and corporate governance committees are composed entirely of independent managers in accordance with NYSE MKT listing standards, SEC requirements and other applicable laws, rules and regulations. There are no transactions, relationships or other arrangements between us and our independent managers that need to be considered under the NYSE MKT listing standards in determining that such persons are independent.

Item 14. Principal Accounting Fees and Services

We engaged our principal accountant, KPMG LLP (KPMG), to audit our financial statements and perform other professional services beginning in the fiscal year ended December 31, 2013. Prior to the engaging of KPMG, our principal accountant was PricewaterhouseCoopers LLP. PricewaterhouseCoopers LLP, audited our financial statements and performed other professional services for the fiscal year ended December 31, 2012.

Audit Fees. The aggregate fees billed for the financial statement audit or services provided in connection with statutory or regulatory filings for the years ended 2013 and 2012 were $600,000 and $804,201, respectively.

Audit-Related Fees. There have been no audit-related fees billed by KPMG for the year ended 2013. There were no aggregate audit-related fees billed by PricewaterhouseCoopers LLP for the year ended 2012.

Tax Fees. There were no tax fees billed by KPMG for the year ended 2013. The aggregate fees related to the preparation of K-1 statements and tax services for the year ended 2012 were $381,390, billed by PricewaterhouseCoopers LLP.

All Other Fees. There were no other fees billed by our principal accountant for the years ended 2013 and 2012.

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. In addition, 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. All of the services described as Audit-Related Fees, Tax Fees and All Other Fees were approved by the audit 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:

Report of Independent Registered Public Accounting Firm dated March 27, 2014 of KPMG LLP

Report of Independent Registered Public Accounting Firm dated March 8, 2013 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Loss—Constellation Energy Partners LLC for the two years ended December 31, 2013

Consolidated Balance Sheets—Constellation Energy Partners LLC at December 31, 2013 and December 31, 2012

Consolidated Statements of Cash Flows—Constellation Energy Partners LLC for the two years ended December 31, 2013

Consolidated Statements of Changes in Members' Equity—Constellation Energy Partners LLC for the two years ended December 31, 2013

Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

Schedules are omitted as not applicable or not required

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

Exhibit Number	Description
2.1	— Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.2	

—Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC, Kansas Production EQR, LLC and Kansas Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).

2.3 —Agreement of Merger, dated as of July 12, 2007, among AMVEST Osage, Inc., AMVEST Oil & Gas, Inc. and CEP Mid-Continent LLC, f/k/a CEP Cherokee Basin LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).

2.4 —Purchase and Sale Agreement, dated as of August 2, 2007, between Newfield Exploration Mid-Continent Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).

2.5 —Nominee Agreement, dated as of September 21, 2007, by and between Newfield Exploration Mid-Continent Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).

2.6 —Asset Purchase and Sale Agreement, dated as of May 12, 2005, by and among Everlast Energy LLC, RB Marketing Company LLC, Robinson's Bend Operating Company LLC and CBM Equity IV, LLC (incorporated herein by reference to Exhibit 10.9 to Amendment No. 2 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on September 29, 2006.

2.7 —Agreement for Purchase and Sale, dated as of February 19, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).

2.8 —First Amendment to Agreement for Purchase and Sale, dated as of March 31, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).

2.9 —Oil and Gas Purchase Contract, dated as of October 1, 1993, by and between Torch Energy Marketing, Inc. and Torch Royalty Company (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2 to the Registration Statement on Form S-1 filed by Constellation Energy Partners LLC on June 29, 2006, File No. 333-134995).

2.1 —Membership Interest Purchase and Sale Agreement, dated February 1, 2013 between Constellation Energy Partners LLC and Constellation Commodities Upstream LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report and Form 8-K filed by Constellation Energy Partners LLC on February 4, 2013, File No. 001-33147).

2.11 —Contribution Agreement, dated as of August 9, 2013, by and between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K field by Constellation Energy Partners LLC on August 9, 2013, 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 as of April 23, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).

3.4 —Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of July 25, 2007. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).

3.5 —Amendment No. 3 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of September 21, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).

3.6 —Amendment No. 4 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of December 28, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on December 28, 2007, File No. 001-33147).

3.7 —Amendment No. 5 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of August 9, 2013 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).

10.1 —Second Amended and Restated Credit Agreement dated as of May 30, 2013, among Constellation Energy Partners LLC, as borrower, Societe Generale, as administrative 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 May 31, 2013, File No. 001-33147).

10.2 —Trademark License Agreement, dated as of November 20, 2006, by and among Constellation Energy Group, Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).

10.3 —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).

10.4 —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).

10.5 —Assignment, Assumption and Ratification Agreement, dated as of July 25, 2007, by and between AMVEST Osage, Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 10.25 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).

10.6 —Water Gathering and Disposal Agreement, dated as of August 9, 1990, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.17 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).

10.7 —First Amendment to Water Gathering and Disposal Agreement, dated as of October 1, 1993, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.18 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).

10.8 —Second Amendment to Water Gathering and Disposal Agreement, dated as of November 30, 2004, by and between Robinson’s Bend Operating Company, LLC and Everlast Energy LLC (incorporated herein by reference to Exhibit 10.19 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).

10.9 —Third Amendment, dated June 13, 2011, to Water Gathering and Disposal Agreement dated November 30, 2004, by and between Robinson’s Bend Operating II, LLC, Robinson’s Bend Production II, LLC and Torch Energy Associates Ltd. (incorporated herein by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 15, 2011, File No. 001-33147).

10.1 —Amended and Restated Employment Agreement, dated April 5, 2012, 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 filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).

10.11 —Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. 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 April 6, 2012, File No. 001-33147).

10.12 —Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Lisa J. Mellencamp (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).

10.13 —Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Michael B. Hiney (incorporated herein by reference to Exhibit 10.4 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).

10.14 —Employment Agreement, dated as of February 15, 2013, between Elizabeth Ann Evans and CEP Services Company, Inc. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on February 19, 2013, File No. 001-33147).

10.15 —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).

10.16	—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).
10.17	—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).
10.18	—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).
10.19	—Form of Grant Agreement Relating to Restricted Units—Executives (under the 2009 Omnibus Incentive Compensation Plan incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on March 3, 2010, File No. 001-33147).
+10.20	—Form of Amended and Restated Grant Agreement Relating to Unit-Based Awards—Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on August 5, 2011, File No. 001-33147).
+10.21	—Amendment to Amended and Restated Grant Agreement Relating to Unit-Based Awards-Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on May 10, 2012, File No. 001-33147).
+10.22	—Form of Grant Agreement Relating to Restricted Units—Independent Managers (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.30 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 25, 2010, File No. 001-33147).
+10.23	—Registration Rights Agreement, dated as of August 9, 2013, between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).
*21.1	—List of subsidiaries of Constellation Energy Partners LLC.
*23.1	—Consent of KPMG LLP.
*23.2	—Consent of PricewaterhouseCoopers LLP.
*23.3	—Consent of Netherland, Sewell & Associates, Inc.
*31.1	—Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	—Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	

	—Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	—Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	—Report of Netherland, Sewell & Associates, Inc.
*101.INS	—XRBL Instance Document
*101.SCH	—XRBL Schema Document

*101.CAL —XRBL Calculation Linkbase Document

*101.LAB —XRBL Label Linkbase Document

*101.PRE —XRBL Presentation Linkbase Document

*101.DEF —XRBL Definition Linkbase Document

*Filed herewith

+Management contract or compensatory plan or arrangement.

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheet of Constellation Energy Partners LLC and subsidiaries as of December 31, 2013, and the related consolidated statements of operations and comprehensive loss, members' equity, and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit. The accompanying consolidated financial statements of Constellation Energy Partners LLC and subsidiaries as of December 31, 2012, were audited by other auditors whose report thereon dated March 8, 2013, expressed an unqualified opinion on those statements, before the discontinued operations adjustments described in Note 2 to the consolidated financial statements.

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

In our opinion, the 2013 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Constellation Energy Partners LLC and subsidiaries as of December 31, 2013, and the results of their operations and their cash flows for the year then ended in conformity with U.S. generally accepted accounting principles.

We also have audited the adjustments described in Note 2 that were applied to retrospectively adjust the 2012 consolidated financial statements for discontinued operations. In our opinion, such adjustments are appropriate and have been properly applied. We were not engaged to audit, review, or apply any procedures to the 2012 consolidated financial statements of the Company other than with respect to the adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2012 consolidated financial statements taken as a whole.

/s/KPMG LLP

Houston, Texas

March 27, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated balance sheets as of December 31, 2012 and the related consolidated statements of operations and comprehensive income (loss), of cash flows and of changes in members' equity for the year then ended, before the effects of the adjustments to retrospectively reflect the discontinued operations described in Note 2, present fairly, in all material respects, the financial position of Constellation Energy Partners LLC and its subsidiaries at December 31, 2012, and the results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America (the 2012 financial statements before the effects of the adjustments discussed in Note 2 are not presented herein). 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 audit. We conducted our audit, before the effects of the adjustments described above, 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

Subsequent to December 31, 2012, the Company entered into an asset sale transaction and extended its reserve based credit facility to March 31, 2014.

We were not engaged to audit, review, or apply any procedures to the adjustments to retrospectively reflect the discontinued operations described in Note 2 and accordingly, we do not express an opinion or any other form of assurance about whether such adjustments are appropriate and have properly applied. Those adjustments were audited by other auditors

/s/ PricewaterhouseCoopers LLP

Houston, Texas

March 8, 2013

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Loss

(In thousands, except per unit data)

	Year Ended December 31,	
	2013	2012
Revenues		
Natural gas sales	$ 23,129	$ 34,019
Oil and liquid sales	20,948	12,508
Total revenues	44,077	46,527
Expenses:		
Operating expenses:		
Lease operating expenses	18,858	19,411
Cost of sales	1,455	1,299
Production taxes	2,601	1,646
General and administrative	22,214	15,747
Loss on sale of assets	4	7
Depreciation, depletion and amortization	18,972	11,732
Asset impairments (See Note 7)	2,357	109
Accretion expense	519	459
Total operating expenses	66,980	50,410
Other expense / (income)		
Interest expense	3,150	5,734
Other income	(196)	(155)
Total other expenses	2,954	5,579
Total expenses	69,934	55,989
Loss from continuing operations	(25,857)	(9,462)
Loss from discontinued operations	(2,686)	(77,081)
Net loss	$ (28,543)	$ (86,543)
Change in fair value of commodity hedges	-	202
Cash settlement of commodity hedges	-	(5,639)
Other comprehensive loss	-	(5,437)
Comprehensive loss	$ (28,543)	$ (91,980)
Loss per unit (See Note 1)		
Loss from continuing operations per unit		
Class A units - Basic and diluted	$ (0.55)	$ (0.39)
Class B units - Basic and diluted	$ (1.01)	$ (0.39)
Discontinued operations per unit		
Class A units - Basic and diluted	$ (0.06)	$ (3.19)
Class B units - Basic and diluted	$ (0.10)	$ (3.19)
Net loss per unit		
Class A units - Basic and diluted	$ (0.61)	$ (3.58)

Class B units - Basic and diluted	$ (1.11)	$ (3.58)
Weighted Average Units Outstanding		
Class A units - Basic and diluted	933,613	483,564
Class B units - Basic and diluted	25,210,106	23,687,946
Distributions declared and paid per unit	$ —	$ —

See accompanying notes to consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

(In thousands, except unit data)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 4,894	$ 1,959
Accounts receivable	6,678	5,615
Prepaid expenses	2,547	1,309
Risk management assets (See Note 5)	9,141	17,965
Current assets from discontinued operations	-	1,886
Total current assets	23,260	28,734
Oil and natural gas properties (See Note 7)		
Oil and natural gas properties, equipment and facilities	639,156	594,020
Material and supplies	1,054	771
Less accumulated depreciation, depletion, amortization, and impairments	(495,215)	(474,669)
Net oil and natural gas properties	144,995	120,122
Other assets		
Debt issue costs (net of accumulated amortization of $9,003 and $7,775, respectively)	824	1,168
Risk management assets (See Note 5)	1,461	7,431
Restricted cash	1,748	600
Other non-current assets	2,245	2,594
Long-term assets from discontinued operations	-	67,373
Total assets	$ 174,533	$ 228,022
LIABILITIES AND MEMBERS' EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 12	$ 480
Accrued liabilities	12,763	7,174
Royalty payable	1,242	1,418
Risk management liabilities (See Note 5)	-	523
Debt (See Note 6)	-	50,000
Current liabilities from discontinued operations	-	1,578
Total current liabilities	14,017	61,173
Other liabilities		
Asset retirement obligation	9,513	7,665
Risk management liabilities (See Note 5)	-	637
Other non-current liabilities	1,398	589
Debt (See Note 6)	50,700	34,000
Other long-term liabilities from discontinued operations	-	7,692

Total other liabilities	61,611	50,583
Total liabilities	75,628	111,756
Commitments and contingencies (See Note 10)	-	-
Members’ equity		
Class A units, 1,615,017 and 483,418 units authorized, issued and outstanding at December 31, 2013 and 2012, respectively	2,591	2,326
Class B units, 28,848,785 and 24,124,378 units authorized, and 28,462,185 and 23,687,507 issued and outstanding at December 31, 2013 and 2012, respectively	96,314	113,940
Total members’ equity	98,905	116,266
Total liabilities and members’ equity	$ 174,533	$ 228,022

See accompanying notes to consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Cash Flows

(In thousands)

	Year Ended December 31,	
	2013	2012
Cash flows from operating activities:		
Net loss	$ (28,543)	$ (86,543)
Adjustments to reconcile net loss to cash provided by operating activities:		
Depreciation, depletion and amortization	18,972	11,732
Asset impairments (See Note 7)	2,357	109
Amortization of debt issuance costs	1,289	1,310
Accretion expense	519	459
Equity earnings in affiliate	(271)	(173)
Loss from disposition of property and equipment	4	7
Bad debt expense	44	35
Mark-to-market on derivatives:		
Total gains	1,551	(14,640)
Cash settlements	12,082	22,189
Unit-based compensation programs	1,049	1,497
Discontinued operations	2,686	77,081
Changes in Assets and Liabilities:		
Increase in accounts receivable	(1,106)	(924)
Increase in prepaid expenses	(1,238)	(144)
Decrease in other assets	8	-
Decrease in accounts payable	(468)	(370)
Increase (decrease) in accrued liabilities	4,824	(2,446)
Increase (decrease) in royalty payable	(176)	115
Increase in other liabilities	559	493
Net cash provided by continuing operations	14,142	9,787
Net cash provided by discontinued operations	1,062	4,421
Net cash provided by operating activities	15,204	14,208
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash acquired	(20,221)	(252)
Development of natural gas properties	(15,694)	(15,336)
Proceeds from sale of property and equipment	58,987	1,508
Increase in cash held for escrow	(1,148)	(600)
Distributions from equity affiliate	245	230
Net cash provided by (used in) continuing operations	22,169	(14,450)

Net cash used in discontinued operations	-	(302)
Net cash (used in) investing activities	22,169	(14,752)
Cash flows from financing activities:		
Members' distributions	-	-
Proceeds from issuance of debt	16,894	-
Repayment of debt	(50,194)	(14,400)
Units tendered by employees for tax withholdings	(185)	(200)
Debt issue costs	(953)	(55)
Net cash used in continuing operations	(34,438)	(14,655)
Net cash used in discontinued operations	-	-
Net cash used in financing activities	(34,438)	(14,655)
Net increase (decrease) in cash	2,935	(15,199)
Cash and cash equivalents, beginning of period	1,959	17,158
Cash and cash equivalents, end of period	$ 4,894	$ 1,959
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ (1,674)	$ 307
Cash received during the period for interest	$ -	$ 1
Cash paid during the period for interest	$ (1,881)	$ (3,650)
Cash paid during the period for income taxes	$ (75)	$ (19)

See accompanying notes to consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Changes in Members' Equity

(In thousands, except unit data)

	Class A Units	Amount	Class B Units	Amount	Accumulated Other Comprehensive Income	Total Members' Equity
Balance, December 31, 2011	485,033	$ 4,030	23,766,632	$ 197,453	$ 5,437	$ 206,920
Distributions	—	—	—	—	—	—
Units tendered by employees for tax withholding	(1,845)	(4)	(90,425)	(196)	—	(200)
Change in fair value of commodity hedges	—	—	—	—	202	202
Cash settlement of commodity hedges	—	—	—	—	(5,639)	(5,639)
Unit-based compensation programs	230	31	11,300	1,495	—	1,526
Net loss	—	(1,731)	—	(84,812)	—	(86,543)
Balance, December 31, 2012	483,418	$ 2,326	23,687,507	$ 113,940	$ —	$ 116,266
Distributions	—	—	—	—	—	—
Units tendered by employees for tax withholding	(2,853)	(4)	(139,810)	(181)	—	(185)
Unit-based compensation programs	3,940	21	190,081	1,028	—	1,049
Units issued for acquisition of properties	1,130,512	818	4,724,407	9,500	—	10,318
Net loss	—	(570)	—	(27,973)	—	(28,543)
Balance, December 31, 2013	1,615,017	$ 2,591	28,462,185	$ 96,314	$ —	$ 98,905

See accompanying notes to consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013 and 2012

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 currently trade on the NYSE MKT LLC (NYSE MKT) under the symbol “CEP”. Through subsidiaries, PostRock Energy Corporation (NASDAQ: PSTR) (PostRock), Exelon Corporation (NYSE: EXC) (Exelon) and Sanchez Oil & Gas Corporation (SOG) own a portion of our outstanding units. As of December 31, 2013, Constellation Energy Partners Management, LLC (CEPM), a subsidiary of PostRock, owned 484,505, or 30%, of our Class A units and 5,918,894 of our Class B common units. Constellation Energy Partners Holdings, LLC (CEPH), a subsidiary of Exelon, owned all of our Class C management incentive interests and all of our Class D interests. Sanchez Energy Partners I, LP (SEP I), an affiliate of SOG, owned 1,130,512, or 70%, of our Class A units and 4,724,407 of our Class B common units.

We are currently focused on the acquisition, development and production of oil and natural gas properties, as well as midstream assets. Our proved reserves are located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas and in Texas and Louisiana.

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.

Use of Estimates

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

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

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

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

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

These estimates involve judgments with respect to numerous factors that are difficult to predict and are beyond management's control. As a result, changes in facts and circumstances or additional information may result in revised estimates or actual amounts may materially differ from these amounts.

Reclassifications

Certain reclassifications have been made to the prior periods to conform to the current period presentation. These reclassifications had no effect on total assets, total liabilities, total unitholders' equity, net income or net cash provided by or used in operating, investing or financing activities.

Discontinued Operations

In February 2013, we sold all of our Robinson's Bend Field assets in the Black Warrior Basin of Alabama. The related results of operations and cash flows have been classified as discontinued operations in the consolidated statements of operations, balance sheets, statements of cash flows and consolidated financial information. Unless otherwise indicated, information presented in the Notes to Consolidated Financial Statements relates only to the Company's continuing operations. Information related to discontinued operations is included in Note 2. Discontinued Operations.

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash equivalents. Checks-in-transit were none in 2013 and $0.6 million in 2012 and are included in accounts payable in our consolidated balance sheets.

Restricted Cash

Restricted cash at December 31, 2013 of $1.7 million is held in escrow in relation to the sale of the Robinson's Bend Field assets and related to litigation involving one of our service providers. Restricted cash at December 31, 2012 was comprised of $0.6 million held in escrow related to litigation involving one of our service providers.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject us to a concentration of credit risk consist of cash and cash equivalents, accounts receivable and derivative financial instruments. We place our cash with high credit quality financial institutions. We place our derivative financial instruments with financial institutions that participate in our reserve-based credit facility and maintain an investment grade credit rating. Substantially all of our accounts receivables are due from purchasers of oil and natural gas. These sales are generally unsecured and, in some cases, may carry a parent guarantee. As we generally have fewer than 10 large customers for our oil and natural gas sales, we routinely assess the financial strength of our customers. Bad debt expense is recognized on an account-by-account review and when recovery is not probable. Our allowance for doubtful accounts was less than $0.1 million in each of 2012 and 2013. We have no off-balance-sheet credit exposure related to our operations or customers.

For the year ended December 31, 2013, five customers accounted for approximately 22%, 20%, 17%, 14% and 8% of our sales revenues. For the year ended December 31, 2012, five customers accounted for approximately 28%, 10%, 9%, 9% and 8% of our sales revenues.

Oil and Natural Gas Properties

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for our oil and natural gas exploration, development and production activities. Leasehold acquisition costs, property acquisition and the costs of development of proved areas 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.

Accounting rules require that we price our oil and natural gas proved reserves at the preceding twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. 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, Depletion and Amortization

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. Depreciation, depletion, and amortization expense is calculated using year-end reserve reports based on the SEC-required price. As more fully described in Note 15, proved reserves estimates are subject to future revisions when additional information becomes available.

Asset Retirement Obligation

As described in Note 11, 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.

Unsuccessful Wells

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

Impairment

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 7 for additional information.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that we expect to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period. The valuation allowances are reviewed at least annually.

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.

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. Proved reserves are 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, 2013 and 2012 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 impairments 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 are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Derivatives and Hedging Activities

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

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

Revenue Recognition

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

Gas imbalances occur when sales are more or less than the entitled ownership percentage of total gas production. We use the entitlements method when accounting for gas imbalances. Any amount received in excess is treated as a liability. If less than the entitled share of the production is received, the excess is recorded as a receivable. There were no gas imbalance positions at December 31, 2013 or 2012, respectively.

Income Taxes

CEP and each of its wholly-owned subsidiary LLCs are treated as a partnership for federal and state income tax purposes. 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 and Oklahoma. CEP also has informational filing requirements in Georgia, Indiana, Louisiana, Maine, Missouri, New Jersey, New York, Oregon, Pennsylvania, and West Virginia because we have resident unitholders in these states.

Our wholly-owned subsidiary, CEP Services Company, Inc. is a taxable entity. For the years ended December 31, 2013, and 2012, the current federal and state tax liability for the entity was less than $0.1 million and $0.1 million, respectively. The entity has no deferred tax assets or liabilities. Taxes are paid to the IRS or the applicable states in quarterly installments.

Earnings per Unit

Basic earnings per unit (EPU) is computed by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. To determine net income (loss) allocated to each class of ownership (Class A and Class B), we first allocate net income (loss) in accordance with the amount of distributions made for the period by each class, if any. The remaining net income (loss) is allocated to each class in proportion to the class weighted average number of units outstanding for the period, as compared to the weighted average number of units for all classes for the period.

As of December 31, 2013 and 2012, we had unvested restricted common units outstanding, which were considered dilutive securities. These units will be considered in the diluted weighted average common units outstanding number in periods of net income. In periods of net losses, these units are excluded for the diluted weighted average common unit outstanding number as they are not participating securities.

The following table presents our calculation of basic and diluted units outstanding for the periods indicated:

	Year Ended December 31,	
	2013	2012
Weighted average units outstanding during period:		
Class A units - Basic and Diluted	933,613	483,564
Class B Common units - Basic and Diluted	25,210,106	23,687,946
	26,143,719	24,171,510

At December 31, 2013, we had 380,327 Class B common units that were restricted unvested common units granted and outstanding. These units were excluded from the diluted weighted average common unit outstanding number.

The following table presents our basic and diluted income per unit for the year ended December 31, 2013 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Loss from continuing operations	$ (25,857)		
Distributions	-	$ -	$ -
Assumed allocation of loss from continuing operations	(25,857)	(517)	(25,340)
Discontinued operations	(2,686)	(54)	(2,632)
Assumed net loss to be allocated	$ (28,543)	$ (571)	$ (27,972)
Basic and diluted loss from continuing operations per unit		$ (0.55)	$ (1.01)
Basic and diluted loss from discontinued operations per unit		$ (0.06)	$ (0.10)
Basic and diluted loss per unit		$ (0.61)	$ (1.11)

The following table presents our basic and diluted income per unit for the year ended December 31, 2012 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Loss from continuing operations	$ (9,462)		
Distributions	-	$ -	$ -
Assumed allocation of loss from continuing operations	(9,462)	(189)	(9,273)
Discontinued operations	(77,081)	(1,542)	(75,539)
Assumed net loss to be allocated	$ (86,543)	$ (1,731)	$ (84,812)
Basic and diluted loss from continuing operations per unit		$ (0.39)	$ (0.39)
Basic and diluted loss from discontinued operations per unit		$ (3.19)	$ (3.19)
Basic and diluted loss per unit		$ (3.58)	$ (3.58)

Comprehensive Loss

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

Environmental Cost

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

Unit-Based Compensation

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

Other Contingencies

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

Recent Pronouncements and Accounting Changes

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board (the FASB), which are adopted by us as of the specified effective date. Unless otherwise discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on our consolidated financial statements upon adoption.

In December 2011, the FASB issued ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities, which requires additional disclosures for financial and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, regardless of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. In January 2013, the FASB issued ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, an amendment to ASC Topic 210. The update clarifies that the scope of ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities, applies to derivatives accounted for in accordance with ASC Topic 815, Derivatives and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. The guidance was effective beginning on or after January 1, 2013, and primarily impacts the disclosures associated with our commodity and interest rate derivatives. The adoption of this guidance did not have any impact on our consolidated financial position, results of operations or cash flows.

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

2. DISCONTINUED OPERATIONS

Sale of Robinson's Bend Field Assets

On February 28, 2013, we sold all of our Robinson's Bend Field assets in the Black Warrior Basin of Alabama for $63.0 million, subject to closing adjustments that amounted to approximately $4.0 million. We recorded a loss on the sale of approximately $3.1 million in the three months ended March 31, 2013. The sale of the Robinson's Bend Field assets was initiated to provide the financial flexibility necessary to support our efforts for pursuing opportunities and further developing our properties in the Mid-Continent region, as well as reducing our outstanding debt.

The following amounts relating to the Robinson's Bend Field assets have been reported as discontinued operations in the consolidated statements of operations in the years ending December 31, 2013 and 2012 (in thousands):

	Year Ending December 31,	
	2013	2012
Revenues	$ 2,304	$ 12,808
Loss from discontinued operations	$ (2,686)	$ (77,081)

The loss from discontinued operations for the year ended December 31, 2012 included an impairment charge of approximately $73.3 million to impair the asset group that contained our natural gas properties and inventory in the Robinson's Bend Field. This impairment was recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by the cash offer to purchase the assets for $63.0 million, subject to certain post-closing adjustments.

See Note 1 for information regarding earnings per unit, including earnings per unit data relating to income from discontinued operations, which includes loss on sale of discontinued operations in 2013.

The following table provides the major classes of assets and liabilities components of discontinued operations as of December 31, 2013 and 2012 (in thousands):

	December 31,	
	2013	2012
Accounts receivable	$ -	$ 1,763
Natural gas properties, net	$ -	$ 67,301
Total discontinued assets	$ -	$ 69,259

Accounts payable	$ -	$ 711
Accrued liabilities	$ -	$ 771
Asset retirement obligation	$ -	$ 7,692
Total discontinued liabilities	$ -	$ 9,270

The consolidated statements of cash flows reflect discontinued operations for the years ended December 31, 2013 and 2012.

3. ACQUISITION

Acquisition of Oil, Natural Gas and Natural Gas Liquids Properties from SEP I

On August 9, 2013, we acquired oil, natural gas and natural gas liquids assets in Texas and Louisiana from SEP I for a purchase price of $30.4 million. In conjunction with the acquisitions, SEP I received $20.1 million in cash; 1,130,512 Class A units, which represents 70% of the total Class A units, and 4,724,407 Class B units, which represents 16.6% of the total Class B units. The cash portion of the transaction was financed with cash on hand and a borrowing of $16.7 million under our reserve-based credit facility.

The acquired assets include 67 producing wells in Texas and Louisiana. The primary factors considered by management in acquiring the SEP I properties include the belief that these wells provide an opportunity to significantly increase our reserves, production volumes and drilling portfolio, while maintaining our focus of increasing our oil-weighted assets. The SEP I properties also provide us with access to exploitation and development potential.

The following allocation of the purchase price is preliminary and includes estimates. This preliminary allocation is based on information that was available to management at the time these consolidated financial statements were prepared and takes into account current market conditions and estimated market prices for oil and natural gas. Management has not yet had the opportunity to complete its assessment of fair values of the assets acquired. In addition, the purchase price could change materially as management finalizes adjustments to the purchase price provided for by the purchase and sale agreement, specifically ad valorem taxes, property taxes, franchise taxes and any other state or local taxes. Accordingly, the allocation may change materially as additional information becomes available and is assessed by management.

The following table summarizes the estimated values of assets acquired and liabilities assumed effective August 1, 2013 (in thousands):

Oil and natural gas properties, equipment and facilities	$ 31,497
Asset retirement obligation	(1,088)
Net assets acquired	$ 30,409

We will finalize the purchase price allocation within one year of the acquisition date.

We have accounted for our acquisition of oil and natural gas properties using the purchase method of accounting for business combinations, and therefore we have estimated the fair value of the assets acquired and the liabilities assumed as of the acquisition date. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves, (ii) future operating and development costs; (iii) future commodity prices, (iv) estimated future cash flows and (v) a market-based weighted cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

Results of Operations and Pro Forma Information

The following table sets forth revenues and lease operating expenses attributable to the SEP I properties acquired (in thousands):

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	2012	2013	2012
Revenue	$ 3,018	$ 5,036	$ 15,782	$ 20,939
Lease Operating Expenses	$ 819	$ 997	$ 3,047	$ 4,049

We have determined that the presentation of net income attributable to the SEP I properties is impracticable due to the integration of the related operations upon acquisition.

The following supplemental pro forma information presents consolidated results of operations as if the acquisition of the SEP I properties had occurred on January 1, 2012. The supplemental unaudited pro forma information was derived from a) our historical consolidated statements of operations and b) the statements of operations of SEP I. This information does not purport to be indicative of results of operations that would have occurred had the acquisition occurred on January 1, 2012, nor is such information indicative of any expected future results of operations.

(In thousands)	Pro Forma Three Months Ended December 31, 2013	2012	Pro Forma Twelve Months Ended December 31, 2013	2012
Revenue	$ 11,458	$ 18,473	$ 56,841	$ 67,466
Income (loss) from continuing operations	$ (13,066)	$ 1,093	$ (18,514)	$ 3,825
Discontinued operations	$ -	$ (74,055)	$ (2,686)	$ (77,081)
Net Loss	$ (13,066)	$ (72,962)	$ (21,200)	$ (73,256)
Income (loss) from continuing operations per unit				
Class A units - Basic and diluted	$ (0.16)	$ 0.01	$ (0.23)	$ 0.05
Class B units - Basic and diluted	$ (0.46)	$ 0.04	$ (0.65)	$ 0.13
Discontinued operations per unit				
Class A units - Basic and diluted	$ -	$ (0.92)	$ (0.03)	$ (0.96)
Class B units - Basic and diluted	$ -	$ (2.55)	$ (0.09)	$ (2.66)
Net loss per unit				
Class A units - Basic and diluted	$ (0.16)	$ (0.90)	$ (0.26)	$ (0.91)
Class B units - Basic and diluted	$ (0.45)	$ (2.52)	$ (0.74)	$ (2.53)
Weighted average units outstanding				
Class A units - Basic and diluted	1,615,017	1,613,924	1,615,103	1,614,076
Class B units - Basic and diluted	28,457,577	28,412,032	28,057,592	28,412,353

4. FAIR VALUE MEASUREMENTS

We measure certain financial assets and liabilities at fair value. Fair value is defined as an “exit price” which represents the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in valuing an asset or liability. The accounting guidance also requires the use of valuation techniques to measure fair value that maximize the use of observable inputs and minimize the use of unobservable inputs. As a basis for considering such assumptions and inputs, a fair value hierarchy has been established which identifies and prioritizes three levels of inputs to be used in measuring fair value.

The three levels of the fair value hierarchy are as follows:

Level 1 – Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 – Inputs other than the quoted prices in active markets that are observable either directly or indirectly, including: quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar assets and liabilities in markets that are not active or other inputs that are observable or can be corroborated by observable market data.

Level 3 – Unobservable inputs that are supported by little or no market data and require the reporting entity to develop its own assumptions.

As required by accounting guidance for fair value measurements, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 (in thousands):

	Fair Value Measurements at December 31, 2013				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at December 31, 2013
Risk Mgmt Assets	$ —	$ 11,577	$ —	$ (975)	$ 10,602
Risk Mgmt Liabilities	—	(975)	—	975	—
Total Net Assets and Liabilities	$ —	$ 10,602	$ —	$ —	$ 10,602

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 (in thousands):

	Fair Value Measurements at December 31, 2012				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at December 31, 2012
Risk Mgmt Assets	$ —	$ 31,030	$ —	$ (5,634)	$ 25,396
Risk Mgmt Liabilities	—	(6,794)	—	5,634	(1,160)
Total Net Assets and Liabilities	$ —	$ 24,236	$ —	$ —	$ 24,236

As of December 31, 2013, the estimated fair value of cash and cash equivalents, accounts receivable, other current assets and current liabilities approximated their carrying value due to their short-term nature.

Fair Value of Financial Instruments

Fair value guidance requires certain fair value disclosures, such as those on our debt and derivatives, to be presented in both interim and annual reports. The estimated fair value amounts of financial instruments have been determined using available market information and valuation methodologies described below.

Reserve-Based Credit Facility – We believe that the carrying value of long-term debt for our reserve-based credit facility approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms. The debt is classified as a Level 2 input in the fair value hierarchy and represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties. Our reserve-based credit facility is discussed further in Note 6.

Derivative Instruments – 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 inputs. Our commodity derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of oil and natural gas prices and an appropriate discount rate. Our interest rate derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of the LIBOR interest rates and an appropriate discount rate. We prioritize the use of the highest level inputs available in determining fair value such that fair value measurements are determined using the highest and best use as determined by market participants and the assumptions that they would use in determining fair value.

5. DERIVATIVE AND FINANCIAL INSTRUMENTS

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. These transactions are normally price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never our intention to enter into derivative contracts for speculative trading purposes.

Under ASC Topic 815, "Derivatives and Hedging," all derivative instruments are recorded on the consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We will net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives' fair values are recognized currently in earnings unless specific hedge accounting criteria are met. We have elected to designate only a portion of our current derivative contracts as hedges; however, changes in the fair value of all of our derivative instruments are recognized in earnings and included as realized and unrealized gains (losses) on derivative instruments in the consolidated statements of operations.

As of December 31, 2013, we had the following derivative contracts in place for the periods indicated, all of which are accounted for as mark-to-market activities:

MTM Fixed Price Swaps – NYMEX (Henry Hub)

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2014	1,575,000	$ 5.75	1,592,500	$ 5.75	1,610,000	$ 5.75	1,610,000	$ 5.75	6,387,500	$ 5.75
2015	1,215,420	$ 4.25	1,153,487	$ 4.25	1,096,023	$ 4.26	1,050,219	$ 4.26	4,515,149	$ 4.26
2016	1,010,633	$ 4.21	967,290	$ 4.21	923,541	$ 4.21	893,568	$ 4.22	3,795,032	$ 4.21
									14,697,681	

MTM Fixed Price Basis Swaps – Enable Gas Transmission, LLC (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,		September 30,		December 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
2014	1,178,422	$ 0.39	1,133,022	$ 0.39	1,084,270	$ 0.39	1,047,963	$ 0.39	4,443,677	$ 0.39
									4,443,677	

MTM Fixed Price Basis Swaps – West Texas Intermediate (WTI)

	For the quarter ended (in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2014	60,928	$ 94.64	57,154	$ 94.67	53,797	$ 94.72	50,597	$ 94.80	222,476	$ 94.70
2015	47,747	$ 90.95	45,065	$ 91.00	42,672	$ 91.04	40,329	$ 91.10	175,813	$ 91.02
2016	17,957	$ 85.50	16,985	$ 85.50	16,048	$ 85.50	15,127	$ 85.50	66,117	$ 85.50
									464,406	

The table below outlines the classification of our derivative financial instruments on the consolidated balance sheets (in thousands):

Derivative Type	Location of Asset/(Liability) On Balance Sheet	Fair Value of Asset/(Liability) On Balance Sheet December 31, 2013	December 31, 2012
Commodity – MTM	Risk management assets - current	$ 10,043	$ 19,005
Commodity – MTM	Risk management assets - non-current	1,534	12,025
	Total gross assets	11,577	31,030
Commodity – MTM	Risk management assets – current	(903)	(1,040)
Commodity – MTM	Risk management assets – non-current	(72)	(946)
Commodity – MTM	Risk management liabilities – current	—	(523)
Commodity – MTM	Risk management liabilities – non-current	—	(637)
Interest Rate - MTM	Risk management assets – non-current	—	(3,648)
	Total gross liabilities	(975)	(6,794)
	Total net assets and liabilities	$ 10,602	$ 24,236

The effect of derivative instruments on our consolidated statements of operations was as follows (in thousands):

Derivative Type	Location of Gain/(Loss) in Income	Amount of Gain/(Loss) in Income For the Year Ended December 31, 2013	2012
Commodity – MTM	Oil and natural gas sales	$ (1,486)	$ 15,701
Interest Rate – MTM	Interest expense	(65)	(1,061)
	Total	$ (1,551)	$ 14,640

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 For the Three Months Ended December 31, 2013	2012

Commodity – Cash Flow	Natural gas sales	$ —	$ 1,271
	Total	$ —	$ 1,271

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with two counterparties. We generally execute commodity derivative instruments under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election.

We monitor the creditworthiness of our counterparties; however, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, if such changes are sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of our counterparties not perform, we may not realize the benefit of some of our derivative instruments with lower commodity prices and my incur losses. We include a measure of counterparty credit risk in our estimates of the fair values of the derivative instruments in an asset position.

We currently use our reserve-based credit facility to provide credit support for our derivative transactions. As a result, we do not post cash collateral with our counterparties, and have minimal non-performance credit risk on our liabilities with our counterparties. We utilize observable market data for credit default swaps to assess the impact of non-performance credit risk when evaluating our net assets from counterparties. At December 31, 2013 and 2012, respectively, the impact of non-performance credit risk on the valuation of our net assets from counterparties was not significant

Under the terms of our reserve-based credit facility, we have agreed to hedge 100% of our reasonably estimated projected natural gas production for 2015 and 2016. All of the required hedges were executed prior to December 31, 2013.

Hedge Liquidation, Repositioning and Novation

In connection with the sale of our Robinson's Bend Field assets in the Black Warrior Basin of Alabama, we liquidated 395,218 MMbtu of NYMEX swaps in 2013 and 1,634,530 MMbtu of NYMEX swaps in 2014 at a cost of $0.3 million. In addition, we reduced our outstanding NYMEX swap positions in 2013 by 1,041,814 MMbtu by executing offsetting trades with one of our counterparties at a fixed price of $3.66 per Mcf. These transactions ensure that our outstanding derivative positions in future periods are lower than our expected future natural gas production in those periods. We also amended a 2014 to 2015 oil trade with one of our hedge counterparties to lower the stated swap price from $98.10 to $93.50 per barrel, on a total of 58,157 barrels of oil. We received proceeds of approximately $0.2 million upon execution of the amendment. The proceeds were used for working capital purposes.

In March 2013, we reduced our outstanding interest rate swaps that fixed our LIBOR rate through 2014 to $30 million, which resulted in additional interest rate swap settlements of $2.1 million. This position was terminated in May 2013 resulting in an offsetting non-cash gain in our mark-to-market interest swap activities.

In May 2013, in conjunction with amendments to our reserve-based credit facility and the exit of certain lenders from our bank syndicate, we novated certain of our commodity hedges to Societe General, which increased our natural gas settlement cost by $0.3 million.

6. DEBT

Reserve-Based Credit Facility

In May 2013, we refinanced our $350.0 million reserve-based credit facility with Societe Generale as administrative and collateral agent and a syndicate of lenders, extending its maturity to May 30, 2017 and increasing our borrowing base from $37.5 million to $55.0 million. 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 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, 2013, we had borrowed $50.7 million under our reserve-based credit facility and our borrowing base was $55.0 million. At December 31, 2013, the lenders and their percentage commitments in the reserve-based credit facility were Societe Generale (36.36%), OneWest Bank, FSB (36.36%) and BOKF NA, dba Bank of Oklahoma (27.28%).

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, 2013, no letters of credit were outstanding.

At our election, interest for borrowings is 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. The reserve-based credit facility limits our ability to pay distributions to unitholders and permits us to hedge our projected monthly production, as discussed below, and the interest rate on our borrowings.

In addition, we are required to maintain (i) a ratio of Total Net Debt (defined as Debt (generally indebtedness permitted to be incurred by us under the reserve-based credit facility) less Available Cash (generally, cash, cash equivalents and cash reserves of the Company)) to Adjusted EBITDA (generally, for any period, the sum of consolidated net income for such period plus (minus) the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets, (gain) loss on sale of assets, exploration costs, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on derivatives and realized (gain) loss on cancelled derivatives, and other similar charges) of not more than 3.50 to 1.0; (ii) Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and (iii) consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities and current maturities of debt (to the extent such payments are not past due), of not less than 1.0 to 1.0, all calculated pursuant to the requirements under Accounting Standards Codification (ASC) Topic 815, Derivatives and Hedging; ASC Topic 410, Asset Retirement and Environmental Obligations and ASC Topic 360, Property, Plant and Equipment. All financial covenants are calculated using our consolidated financial information and are discussed below.

The reserve-based credit facility also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, guaranties not being valid under the reserve-based credit facility and a change of control. A change of control is generally defined as the occurrence of both of the following events: (i) wholly-owned subsidiaries of Constellation Energy Group, Inc. are the owner of 20% or less of an interest in us (which has now occurred) and (ii) any person or group of persons acting in concert are the owner of more than 35% of an interest in us. These events have not both occurred, so a change in control had not occurred as of December 31, 2013. If an event of default occurs, the lenders will be able to accelerate the maturity of the reserve-based credit facility and exercise other rights and remedies. The reserve-based credit facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the reserve-based credit facility and would be in default, which could cause all of our existing indebtedness to become immediately due and payable.

The reserve-based credit facility limits our ability to pay distributions to unitholders. We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the reserve-based credit facility, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the reserve-based credit facility exceed 90% of our borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. As of December 31, 2013, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions.

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

The reserve-based credit facility contains no covenants related to PostRock's, Exelon's or SOG's ownership in us.

Compliance with Financial Covenants

At December 31, 2013, 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, 2013, our actual Total Net Debt to annual Adjusted EBITDA ratio was 2.6 to 1.0, compared to a required ratio of not greater than 3.5 to 1.0; our actual ratio of consolidated current assets to consolidated current liabilities was 1.3 to 1.0, compared to a required ratio of not less than 1.0 to 1.0 and our actual quarterly Adjusted EBITDA to cash interest expense ratio was 9.3 to 1.0, compared to a required ratio of not less than 2.5 to 1.0.

If we are unable to remain in compliance with the financial covenants contained in our reserve-based credit facility or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of our reserve-based credit facility, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

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, 2013, our borrowing base was $55.0 million. The borrowing base is re-determined semi-annually, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas prices prevailing at such time. 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.

Funds Available for Borrowing

As of December 31, 2013, we had $50.7 million in outstanding debt under our reserve-based credit facility and $4.3 million in remaining borrowing capacity. At December 31, 2012, we had $84 million in outstanding debt under our reserve-based credit facility.

Debt Issue Costs

As of December 31, 2013, our unamortized debt issue costs were approximately $0.8 million. These costs are being amortized over the life of the credit facility. At December 31, 2012, our unamortized debt issue costs were approximately $1.2 million.

7. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties consist of the following (in thousands):

	December 31, 2013	December 31, 2012
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 636,816	$ 591,889
Unproved property	1,589	1,380
Total property costs	638,405	593,269
Materials and supplies	1,054	771
Land	751	751
Total	640,210	594,791
Less: Accumulated depreciation, depletion, amortization and impairments	(495,215)	(474,669)
Oil and natural gas properties and equipment, net	$ 144,995	$ 120,122

Depreciation, depletion, amortization and impairments consisted of the following (in thousands):

	Year Ended December 31, 2013	Year Ended December 31, 2012
DD&A of oil and natural gas-related assets	$ 18,972	$ 11,732
Asset Impairments	2,357	109
Total	$ 21,329	$ 11,841

Impairment Charges

Our non-cash asset impairment charges for the year ended December 31, 2013 were $2.3 million, compared to $0.1 million for the same period in 2012. Our non-cash impairment charges in 2013 were approximately $2.1 million to impair the value of our oil and natural gas fields in Texas and Louisiana and $0.2 million to impair certain of our wells in the Woodford Shale.

Our non-cash impairment charges in 2012 were approximately $0.1 million to impair certain properties in the Woodford Shale. The impairment 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.

Asset Sales

In 2012, we sold our interests in 14 gross non-operated oil wells in Kansas and Nebraska for approximately $1.4 million in cash, and sold approximately $0.1 million in trucks and equipment resulting in no material gain or loss on the asset sales.

Useful Lives

Our furniture, fixtures and equipment are depreciated over a life of one to seven years, buildings are depreciated over a life of 20 years and pipeline and gathering systems are depreciated over a life of 25 to 40 years.

Exploration and Dry Hole Costs

We recorded no exploration and dry hole costs for the years ended December 31, 2013 and 2012. 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.

8. BENEFIT PLANS

Eligible employees of CEP participate in an employment savings plan. Matching contributions made by us were approximately $0.3 million and $0.5 million years ended December 31, 2013 and 2012, respectively.

9. RELATED PARTY TRANSACTIONS

Unit Ownership

PostRock, Exelon and SOG, through subsidiaries, own a portion of our outstanding units. As of December 31, 2013, CEPM, a subsidiary of PostRock, owned 484,505, or 30%, of our Class A units and 5,918,894 of our Class B common units. CEPH, a subsidiary of Exelon, owned all of our Class C management incentive interests and all of our Class D interests as of December 31, 2013. SEP I, a subsidiary of SOG, owned 1,130,512, or 70%, of our Class A units and 4,724,407 of our Class B common units.

PostRock-Related Announcements

In 2011, PostRock acquired certain of our Class A units and Class B common units in two separate transactions which represented a 21.3% ownership interest in us at December 31, 2013. Approval of the purchase of these units was neither required nor given by our board of managers or conflicts committee. We believe PostRock is now an "interested unitholder" under Section 203 of the Delaware General Corporation Law, which is applicable to us pursuant to our operating agreement. Section 203, as it applies to us, prohibits an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in business combinations with us for three years following the time such person becomes an interested unitholder without the approval of our board of managers and the vote of 66 2/3% of our outstanding Class B common units, excluding those held by the interested unitholder. Section 203 broadly defines "business combination" to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. In addition to limiting our ability to enter into transactions with PostRock or its affiliates, this provision of our operating 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. We believe the Section 203 restrictions related to these unit purchases expire in December 2014.

Sanchez-Related Announcements

In August 2013, SOG acquired certain of our Class A units and Class B common units and one Class Z unit in one transaction which represented a 19.5% ownership interest in us at December 31, 2013. These units were issued to SOG, along with cash, in exchange for oil and natural gas properties located in Texas and Louisiana.

In August 2013, the Company also entered into a Registration Rights Agreement with SOG pursuant to which the Company granted to SOG certain registration rights related to the unit consideration thereunder. Under the Registration Rights Agreement, the Company granted SOG demand registration rights with respect to the preparation and filing with the SEC of one or more registration statements for the purpose of registering the resale of the securities that will be registered.

Class C Management Incentive Interests

CEPH, a subsidiary of Exelon, holds the Class C management incentive interests in CEP. These management incentive interests represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in our operating agreement) has been achieved and certain other tests have been met. None of these applicable tests have yet to be met and CEPH has not been entitled to receive any management incentive interest distributions or share in distributions upon liquidation.

Class D Interest

The majority of our properties in the Robinson's Bend Field were subject to a non-operated net profits interest (NPI) held by Torch Energy Royalty Trust (the Trust). Through the NPI, the Trust was entitled to a royalty payment, calculated as a percentage of the net revenue from specified wells in the Robinson's Bend Field (the Trust Wells).

Under the terms of the NPI and related contractual arrangements, the royalty payment we were required to make to the Trust under the NPI was calculated using a sharing arrangement with a pricing formula that had resulted in below-market prices and had the effect of keeping our payments to the Trust significantly lower than if such payments had been calculated on then prevailing market prices.

In order to address the risks of 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 and the potential reduction in our revenues resulting therefrom, Constellation Holdings, Inc. (CHI) contributed $8.0 million to us for all of our Class D interests. This contribution was potentially to be distributed to CHI in 24 distributions over a period of approximately six years if the sharing arrangement remained in effect during that period. If the amounts payable by us to the Trust were not calculated based on the continued applicability of the sharing arrangement through December 31, 2012, unless such change was approved in advance by our board of managers and our conflicts committee, the following would occur: the Class D interests would cease receiving the cash distributions; and the Class D interest would only be returned the remaining undistributed amount of the $8.0 million contribution under certain circumstances upon our liquidation.

No payments for the NPI were ever made to the Trust. 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 Circuit Court). The lawsuit alleged, among other things, a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserted that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit sought unspecified damages and an accounting of the NPI. The lawsuit was settled in June 2011. The settlement with Trust Venture, its successor and the Trust provided, among other things, that we pay $1.2 million to reimburse Trust Venture and its successor for their legal fees and expenses incurred in prosecuting the lawsuit and that we acquire the NPI from the Trust for $1.0 million. When the NPI was assigned to us by the Trust in the fourth quarter of 2011, the NPI was extinguished. We recognized a $1.0 million charge to impair the value of the extinguished NPI contract that was acquired. The finalization of this settlement impacted our Class D interests. The NPI no longer burdened our properties in the Robinson's Bend Field upon their sale in February 2013.

CEPH, a subsidiary of Exelon and the successor to CHI, holds all of our Class D interests. Due to their contingently redeemable feature, the Class D interests were treated as temporary equity. Since the NPI is no longer being paid based upon the sharing arrangement and we have suspended distributions since June 2009, there should be no further distributions required on the Class D interests. Accordingly, the Class D interests were moved from temporary equity to permanent equity (Class A and Class B) in the fourth quarter of 2011. The Class D interests will remain outstanding until the liquidation of CEP and could receive up to $6.7 million under certain circumstances at that time.

Class Z Unit

SOG holds the one Class Z unit of CEP. This one unit is a non-voting unit, except voting as a separate class must approve the issuance of additional Company securities, other than Class B common units, prior to the issuance of such securities. The Class Z unit is a non-economic interest, without any right to participate in distributions or allocations.

10. COMMITMENTS AND CONTINGENCIES

On August 30, 2013, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPM, Gary M. Pittman and John R. Collins against the Company, certain of its officers and managers, SOG and SEP I in connection with the Company's closing on August 9, 2013 of the purchase of oil and natural gas properties from SEP I and the issuance of units in connection therewith. The plaintiffs contend, among other things, that the issuance of the units to SEP I in connection with the acquisition was not permitted under the Company's operating agreement, that Messrs. Pittman and Collins should not have been removed as the Class A managers of the Company's board of managers, and that SEP I, SOG and our current Class A managers participated in the bad faith conduct of the other defendants and interfered with CEPM's contractual rights under the Company's operating agreement. The plaintiffs allege claims against the Company and certain of its managers and officers relating to breach of contract, breach of the duty of good faith, and breach of the implied covenant of good faith and fair dealing; the plaintiffs also allege aiding and abetting and tortuous interference claims against SOG, SEP I and our current Class A managers. The plaintiffs seek, among other things, declaratory relief reappointing Messrs. Pittman and Collins to the Company's board of managers and removing our current Class A managers therefrom, and an injunction against the Company taking any further action outside the ordinary course of business during the pendency of the litigation, declaratory relief rescinding the units issued by the Company to SEP I, declaratory relief that CEPM has sole voting power with respect to the outstanding Class A units, declaratory relief that the Company officers and managers have breached fiduciary and contractual duties and are not entitled to indemnification from the Company as a result thereof, and monetary damages. The parties to the lawsuit are currently working on the terms of a settlement agreement. In anticipation of a settlement being reached, we have accrued a probable liability of $5.9 million.

11. 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 oil and natural gas properties, equipment and facilities. Subsequently, the ARC is depreciated using a systematic and rational method over the asset's useful life. The AROs recorded by us relate to the plugging and abandonment of oil and natural gas wells, and decommissioning of oil and natural gas gathering and other 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 (in thousands):

	December 31, 2013	December 31, 2012
Asset retirement obligation, beginning balance	$ 7,665	$ 7,052
Liabilities added from acquisitions	1,088	-
Liabilities added from drilling	244	162
Settlements	(3)	(8)
Accretion expense	519	459
Asset retirement obligation, ending balance	$ 9,513	$ 7,665

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 2013 and 2012, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing asset retirement obligations.

12. UNIT-BASED COMPENSATION

We have the following unit-based compensation plans:

We have the 2009 Omnibus Incentive Compensation Plan (Omnibus Plan), which is a plan under which restricted common unit awards are granted to certain employees in Texas. The Omnibus Plan provides for a variety of unit-based and performance-based awards, including unit options, restricted units, unit grants, notional units, unit appreciation rights, performance awards and other unit-based awards. Awards under the Omnibus Plan may be paid in cash, units or any combinations thereof as determined by the compensation committee of our board of managers.

Restricted unit activity (number of units) under the Omnibus Plan was as follows:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit

Outstanding at December 31, 2011	962,281	$ 3.41
Vested	(215,308)	3.40
Granted	7,190	1.32
Returned/Cancelled	(87,385)	3.40
Outstanding at December 31, 2012	666,778	3.39
Vested	(370,363)	2.66
Granted	184,313	1.27
Returned/Cancelled	(144,177)	2.77
Outstanding at December 31, 2013	336,551	$ 3.29

We have the Long-Term Incentive Program (L-TIP), which is a plan under which restricted common unit awards are granted to certain field employees in Alabama, Kansas and Oklahoma and to certain employees in Texas.

Restricted unit activity (number of units) under the L-TIP Plan was as follows:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2011	149,869	$ 3.44
Vested	(56,025)	3.42
Granted	30,000	2.17
Returned/Cancelled	(28,930)	3.42
Outstanding at December 31, 2012	94,914	3.05
Vested	(61,273)	2.24
Granted	38,023	1.17
Returned/Cancelled	(27,888)	2.56
Outstanding at December 31, 2013	43,776	$ 2.87

We recognized approximately $1.0 million and $1.5 million of non-cash compensation expense related to our unit-based compensation plans in the twelve months ended December 31, 2013 and 2012, respectively. As of December 31, 2013, we had approximately $0.5 million in unrecognized compensation expense related to our unit-based compensation plans expected to be recognized through the first quarter of 2015.

13. DISTRIBUTIONS TO UNITHOLDERS

Beginning in June 2009, we suspended our quarterly distributions to unitholders. For twelve months ended December 31, 2013 and 2012, respectively, 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.

14. MEMBERS’ EQUITY

2013 Equity

At December 31, 2013, we had 1,615,017 Class A units and 28,462,185 Class B common units outstanding, which included 43,776 unvested restricted common units issued under our Long-Term Incentive Plan and 336,551 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan.

At December 31, 2013, we had granted 346,734 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 302,958 have vested.

At December 31, 2013, we had granted 1,366,666 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 1,030,115 have vested.

For the year ended December 31, 2013, 139,810 common units were 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.

2012 Equity

At December 31, 2012, we had 483,418 Class A units and 23,687,507 Class B common units outstanding, which included 94,914 unvested restricted common units issued under our Long-Term Incentive Plan and 666,778 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan.

At December 31, 2012, we had granted 336,599 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 241,685 have vested. We also granted an additional 76,046 performance units under our Long-Term Incentive Plan. Of these grants, 38,023 have vested.

At December 31, 2012, we had granted 1,326,530 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 659,752 have vested. We also granted an additional 323,194 performance units under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 161,597 have vested.

For the year ended December 31, 2012, 90,425 common units were tendered by our employees for tax withholding purposes. These units, costing approximately $0.2 million, were returned to their respective plan and are available for future grants.

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.

In February 2013, we sold all of our Robinson’s Bend Field assets in the Black Warrior Basin of Alabama. Information related to these assets is classified as discontinued operations.

Costs

The following table sets forth capitalized costs for the years ended December 31, 2013 and 2012 (in thousands):

	December 31,	
	2013	2012
Capitalized costs at the end of the period:		
Oil and natrual gas properties and related equipment (successful efforts method)		
Property costs		
Proved property	$ 636,816	$ 591,889
Unproved property	1,589	1,380
Total property costs	638,405	593,269
Materials and supplies	1,054	771
Land	751	751
Total	640,210	594,791
Less: Accumulated depreciation, depletion, amortization and impairments	(495,215)	(474,669)
Oil and natural gas properties and equipment, net	$ 144,995	$ 120,122

(a)Capitalized costs include the cost of equipment and facilities for our oil and natural gas producing activities. Proved property costs include capitalized costs for leaseholds holding proved reserves; development wells and related equipment and facilities (including uncompleted development well costs); and support equipment. Unproved property costs include capitalized costs for oil and natural gas leaseholds where proved reserves do not exist.

The following table sets forth costs incurred for oil and natural gas producing activities for the years ended December 31, 2013 and 2012 (in thousands):

	For the year ended December 31,	
	2013	2012
Costs incurred for the period:		
Acquisition of properties		
Proved	$ 20,012	$ 75
Unproved	209	177
Development costs	15,694	15,336
Oil and natural gas properties and equipment, net	$ 35,915	$ 15,588

The development costs for the years ended December 31, 2013 and 2012 primarily represent costs to develop our proved undeveloped reserves. The properties acquired in 2013 were in Texas and Louisiana.

We had no exploration and dry hole costs in 2013 and 2012, respectively.

Results of Operations

The revenues and expenses associated directly with oil and natural gas producing activities are reflected in the Consolidated Statements of Operations and Comprehensive Income (Loss). All of our operations are oil and natural gas producing activities located in the United States.

Net Proved Oil and Natural Gas Reserves

The following table sets forth information with respect to changes in proved developed and undeveloped reserves. This information excludes reserves related to royalty and net profit interests. All of our reserves are located in the United States.

	For the year ended December 31,	
	2013	2012
(In Mmcfe)		
Beginning balance	92,982	201,330
Extensions and discoveries	4,825	2,049
Purchases of reserves in place	7,150	-
Sales of reserves in place	(49,385)	(256)
Revisions of previous estimates	44,727	(97,178)
Production	(9,045)	(12,963)
Ending balance	91,254	92,982
Ending balance from continuing operations	91,254	43,596
Ending balance from discontinued operations	-	49,386
Total ending balance	91,254	92,982
Proved developed reserves from continuing operations	78,629	40,867
Proved developed reserves from discontinued operations	-	49,134
Total proved developed reserves	78,629	90,001
Proved undeveloped reserves from continuing operations	12,625	2,729
Proved undeveloped reserves from discontinued operations	-	252
Total proved undeveloped reserves	12,625	2,981

In February 2013, we sold all of our Black Warrior Basin properties.

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 December 31, 2013 and 2012 proved reserve estimates were 91.3 Bcfe and 93.0 Bcfe, respectively. For these years, NSAI, an independent petroleum engineering firm, prepared the estimates of our proved reserves which were used to prepare our financial statements.

Our 2013 estimates of total proved reserves decreased 1.7 Bcfe from 2012 due to the sale of our Black Warrior Basin properties in the amount of 49 Bcfe offset by the acquisition of the Sanchez properties, which added 7 Bcfe. We added 4.8 Bcfe due to extensions and discoveries in the Cherokee Basin reserves added for oil opportunities. Our reserve revisions of 44.8 Bcfe are primarily the result of higher natural gas prices. Our reserves are 85% natural gas and are sensitive to lower prices for natural gas and basis differentials in the Mid-Continent region. For the proved reserves, the production weighted average product price over the remaining lives of the properties used in our reserve report were: $97.89 per barrel for oil, $41.21 per barrel for natural gas liquids and $3.706 per Mcf for natural gas. Any of our locations that are scheduled to be drilled after 5 years are classified as probable or possible reserves to the extent they are economic.

Our 2012 estimates of total proved reserves decreased 108.3 Bcfe from 2011 due to a lower SEC-required price for natural gas used to calculate our reserves in 2012. We added 2.0 Bcfe due to extensions and discoveries in the Cherokee Basin reserves added for oil opportunities and 0.2 Bcfe of natural gas reserves. Our reserve revisions of 97.2 Bcfe are primarily the result of lower natural gas prices causing our reserves to no longer be considered economic under SEC rules. Our reserves are 93% natural gas and are sensitive to lower prices for natural gas and basis differentials in the Mid-Continent region. Although we utilize swaps and basis swaps to mitigate commodity price risk and basis differentials, these derivatives are not used when preparing our reserve report based on SEC rules. The SEC-required price used to prepare our reserve report was $2.91 in the Cherokee Basin and $2.85 in the Black Warrior Basin. The SEC-required prices used in the Cherokee Basin and in the Black Warrior Basin declined from 2011 to 2012 by $0.97 and $1.35, respectively. Our actual 2012 production of 12.6 Bcfe is 3.8 Bcfe higher than what our 2011 reserve report estimated for 2012. A significant number of our wells that actually produced natural gas in 2012 were not included in our 2011 reserve report as they were deemed uneconomic at the SEC-required price which excludes the impact of our swaps and basis swaps used to mitigate commodity price risk and basis differentials. Any of our locations that are scheduled to be drilled after 5 years are classified as probable or possible reserves to the extent they are economic.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas Reserves, Including a Reconciliation of Changes Therein

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved oil and natural gas reserves. Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below.

Future cash inflows are calculated by applying the SEC-required prices of oil and natural gas relating to our proved reserves to the year-end quantities of those reserves. Future cash inflows exclude the impact of our hedging program. Future development and production costs represent the estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. In addition, asset retirement obligations are included within future production and development costs. There are no future income tax expenses because CEP is a non-taxable entity.

The assumptions used to compute estimated future cash inflows do not necessarily reflect expectations of actual revenues or costs or their present values. In addition, variations from expected production rates could result directly or indirectly from factors outside of our control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production; however, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

The following table summarizes the standardized measure of estimated discounted future cash flows from the oil and natural gas properties (in thousands):

	For the year ended December 31,	
	2013	2012
Future cash inflows	$ 502,831	$ 360,825
Future production costs	(227,315)	(194,198)
Future estimated development costs	(40,694)	(11,124)
Future net cash flows	234,822	155,503
10% annual discount for estimated timing of cash flows	(91,108)	(65,834)

Standardized measure of discounted estimated future net cash flows related to proved gas reserves	$ 143,714	$ 89,669
Standardized measure from continuing operations	143,714	60,455
Standardized measure from discontinued operations	-	29,214
Standardized measure of discounted estimated future net cash flows related to proved gas reserves	$ 143,714	$ 89,669

In February 2013, we sold all of our Black Warrior Basin properties.

The following table summarizes the principal sources of change in the standardized measure of estimated discounted future net cash flows (in thousands):

	For the year ended December 31, 2013	2012
Beginning of the period	$ 89,669	$ 160,691
Sales and transfers of oil and natural gas, net of production costs	(21,244)	(39,699)
Net changes in prices and production costs related to future production	50,425	(19,228)
Development costs incurred during the period	5,615	18,818
Changes in extensions and discoveries	28,494	12,590
Revisions of previous quantity estimates	21,455	(83,750)
Sales of reserves in place	(2,297)	(1,476)
Accretion discount	8,967	16,069
Other	(37,370)	25,654
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 143,714	$ 89,669
Standardized measure from continuing operations	143,714	60,455
Standardized measure from discontinued operations	-	29,214
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 143,714	$ 89,669

In February 2013, we sold all of our Black Warrior Basin properties.

16. SUBSEQUENT EVENTS

The following events have occurred subsequent to the date of the balance sheet or prior to the filing of this Annual Report on Form 10-K that could have a material impact on our consolidated financial statements or results of operations:

On February 28, 2014, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPH against the Company (the Exelon Litigation) seeking repayment of suspended distributions in relation to the Class D Interests held by CEPH. In 2006, Constellation Holding, Inc (CHI), which merged with and into CEPH in December 2012, purchased the Company's Class D Interests for $8.0 million. The $8.0 million was to be repaid to CEPH in quarterly distributions of $333,333.33 over a period of six years; however, these distributions could be temporarily suspended if a dispute arose over pricing formulas related to the sale of natural gas from the Robinson's Bend properties. A dispute arose, so the distributions were suspended pursuant to the Company's operating agreement and never reinstated. CEPH contends, among other things, that the Company breached its contract to pay the quarterly distributions, acted in bad faith and received unjust enrichment by suspending the quarterly distributions. The Company believes that the allegations contained in the lawsuit are without merit and intends to vigorously defend itself against the claims raised in the complaint. In conjunction with its defense in the Exelon Litigation, the Company anticipates that it will incur legal and other costs that may have a material effect on available cash which could impact CEP's ability to make distributions

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.

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CONSTELLATION ENERGY PARTNERS LLC

(REGISTRANT)

Date: March 27, 2014 /S/ STEPHEN R. BRUNNER

By
Stephen R. Brunner

Chief Executive

Officer, Chief Operating Officer and President

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

	Signature	Title	Date
Principal executive officer:			
By	/S/ STEPHEN r. BRUNNER Stephen R. Brunner	Chief Executive Officer, Chief Operating Officer and President	March 27, 2014
Principal financial officer and treasurer:			
By	/S/ CHARLES c. WARD Charles C. Ward	Principal Financial Officer and Principal Accounting Officer	March 27, 2014

Managers:

/S/ RICHARD H. BACHMANN Richard H. Bachmann	Manager	March 27, 2014
/S/ RICHARD S. LANGDON Richard S. Langdon	Manager	March 27, 2014
/S/ ANTONIO R. SANCHEZ Antonio R. Sanchez	Manager	March 27, 2014
/S/ JOHN N. SEITZ John N. Seitz	Manager	March 27, 2014
/S/ GERALD F. WILLINGER Gerald F. Willinger	Manager	March 27, 2014

Exhibit Number	Description
2.1	— Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.2	—Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC, Kansas Production EQR, LLC and Kansas Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.3	—Agreement of Merger, dated as of July 12, 2007, among AMVEST Osage, Inc., AMVEST Oil & Gas, Inc. and CEP Mid-Continent LLC, f/k/a CEP Cherokee Basin LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).
2.4	—Purchase and Sale Agreement, dated as of August 2, 2007, between Newfield Exploration Mid-Continent Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).
2.5	—Nominee Agreement, dated as of September 21, 2007, by and between Newfield Exploration Mid-Continent Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
2.6	—Asset Purchase and Sale Agreement, dated as of May 12, 2005, by and among Everlast Energy LLC, RB Marketing Company LLC, Robinson's Bend Operating Company LLC and CBM Equity IV, LLC (incorporated herein by reference to Exhibit 10.9 to Amendment No. 2 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on September 29, 2006.
2.7	—Agreement for Purchase and Sale, dated as of February 19, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.8	—First Amendment to Agreement for Purchase and Sale, dated as of March 31, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.9	—Oil and Gas Purchase Contract, dated as of October 1, 1993, by and between Torch Energy Marketing, Inc. and Torch Royalty Company (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2 to the Registration Statement on Form S-1 filed by Constellation Energy Partners LLC on June 29, 2006, File No. 333-134995).

2.1	—Membership Interest Purchase and Sale Agreement, dated February 1, 2013 between Constellation Energy Partners LLC and Constellation Commodities Upstream LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report and Form 8-K filed by Constellation Energy Partners LLC on February 4, 2013, File No. 001-33147).
2.11	—Contribution Agreement, dated as of August 9, 2013, by and between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K field by Constellation Energy Partners LLC on August 9, 2013, 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 as of April 23, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).

3.4 —Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of July 25, 2007. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).

3.5 —Amendment No. 3 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of September 21, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).

3.6 —Amendment No. 4 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of December 28, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on December 28, 2007, File No. 001-33147).

3.7 —Amendment No. 5 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of August 9, 2013 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).

10.1 —Second Amended and Restated Credit Agreement dated as of May 30, 2013, among Constellation Energy Partners LLC, as borrower, Societe Generale, as administrative 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 May 31, 2013, File No. 001-33147).

10.2 —Trademark License Agreement, dated as of November 20, 2006, by and among Constellation Energy Group, Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).

10.3 —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).

10.4 —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).

10.5 —Assignment, Assumption and Ratification Agreement, dated as of July 25, 2007, by and between AMVEST Osage, Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 10.25 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).

10.6 —Water Gathering and Disposal Agreement, dated as of August 9, 1990, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.17 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).

10.7 —First Amendment to Water Gathering and Disposal Agreement, dated as of October 1, 1993, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.18 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No.

001-33147).

10.8 —Second Amendment to Water Gathering and Disposal Agreement, dated as of November 30, 2004, by and between Robinson's Bend Operating Company, LLC and Everlast Energy LLC (incorporated herein by reference to Exhibit 10.19 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).

10.9 —Third Amendment, dated June 13, 2011, to Water Gathering and Disposal Agreement dated November 30, 2004, by and between Robinson's Bend Operating II, LLC, Robinson's Bend Production II, LLC and Torch Energy Associates Ltd. (incorporated herein by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 15, 2011, File No. 001-33147).

10.1 —Amended and Restated Employment Agreement, dated April 5, 2012, 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 filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).

10.11 —Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. 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 April 6, 2012, File No. 001-33147).

10.12 —Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Lisa J. Mellencamp (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).

10.13 —Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Michael B. Hiney (incorporated herein by reference to Exhibit 10.4 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).

10.14 —Employment Agreement, dated as of February 15, 2013, between Elizabeth Ann Evans and CEP Services Company, Inc. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on February 19, 2013, File No. 001-33147).

10.15 —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).

10.16 —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).

10.17 —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).

10.18 —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).

10.19 —Form of Grant Agreement Relating to Restricted Units—Executives (under the 2009 Omnibus Incentive Compensation Plan incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on March 3, 2010, File No. 001-33147).

+10.20 —Form of Amended and Restated Grant Agreement Relating to Unit-Based Awards—Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on August 5, 2011, File No. 001-33147).

+10.21 —Amendment to Amended and Restated Grant Agreement Relating to Unit-Based Awards-Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on May 10, 2012, File No. 001-33147).

+10.22 —Form of Grant Agreement Relating to Restricted Units—Independent Managers (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.30 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 25, 2010, File No. 001-33147).

+10.23	—Registration Rights Agreement, dated as of August 9, 2013, between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).
*21.1	—List of subsidiaries of Constellation Energy Partners LLC.
*23.1	—Consent of KPMG LLP.
*23.2	—Consent of PricewaterhouseCoopers LLP.
*23.3	—Consent of Netherland, Sewell & Associates, Inc.
*31.1	—Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	—Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	—Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	—Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	—Report of Netherland, Sewell & Associates, Inc.
*101.INS	—XRBL Instance Document
*101.SCH	—XRBL Schema Document
*101.CAL	—XRBL Calculation Linkbase Document
*101.LAB	—XRBL Label Linkbase Document
*101.PRE	—XRBL Presentation Linkbase Document
*101.DEF	—XRBL Definition Linkbase Document

*Filed herewith

+Management contract or compensatory plan or arrangement.