Constellation Energy Partners LLC
Form 10-K
February 27, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2008

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.)**
100 Constellation Way Baltimore, Maryland	**21202**
(Address of Principal Executive Offices)	**(Zip Code)**

Telephone Number: (410) 468-3500

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

Title of each class	Name of each exchange on which registered
Common Units representing Class B Limited Liability Company Interests	NYSE Arca, Inc.

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

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

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 þ

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 þ 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. þ

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 þ
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 þ

Aggregate market value of Constellation Energy Partners LLC Common Stock, without par value, held by non-affiliates as of June 30, 2008 was approximately $332,083,157 based upon New York Stock Exchange composite transaction closing price.

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

Common Units outstanding on February 20, 2009: 21,938,342 units.

Documents Incorporated by Reference: None

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PART I

Item 1. Business

Overview

We are a limited liability company that was formed by Constellation Energy Group, Inc. (Constellation) in 2005 to acquire oil and natural gas reserves. We are focused on the acquisition, development and production of oil and natural gas properties (E&P properties) as well as related midstream assets. Our primary business objective is to generate stable cash flows allowing us to make quarterly cash distributions to our unitholders. All of our proved reserves are located in the Black Warrior Basin in Alabama, the Cherokee Basin in Kansas and Oklahoma, and in the Woodford Shale in the Arkoma Basin in Oklahoma. Our total estimated proved reserves at December 31, 2008 were approximately 232.4 Bcfe, approximately 68% of which were classified as proved developed, and 99% of which are natural gas. At December 31, 2008, we own approximately 2,763 net producing wells. Our total average proved reserve-to-production ratio of is approximately 13.3 years and our portfolio decline rate is 13 to 15 percent based on our estimated proved reserves at December 31, 2008 and production for the year ended December 31, 2008.

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

Since our formation in 2005, we have expanded our operations by entering into five separate definitive purchase agreements to acquire certain oil and natural gas properties located in the Black Warrior Basin in Alabama, the Cherokee Basin in Kansas and Oklahoma and the Woodford Shale in the Arkoma Basin in Oklahoma. These acquisitions provide us the opportunity to organically grow our business by drilling unproved locations acquired primarily in Osage County, Oklahoma.

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

Business Strategies

Our primary business objective is to generate stable cash flows allowing us to make quarterly cash distributions to our unitholders. In the long term, we are focused on increasing the amount of our future quarterly distributions over time. We plan to achieve our objective by executing our business strategy, which is to:

- organically grow our business by increasing reserves and production through what we believe to be low-risk development drilling that focuses on capital efficient production growth;
- reduce the volatility in our revenues resulting from changes in oil and natural gas commodity prices through efficient hedging programs;
- make accretive acquisitions of E&P properties characterized by a high percentage of proved developed reserves with long-lived, stable production and low-risk drilling opportunities, which may include associated midstream assets such as gathering systems, compression, dehydrating and treating facilities and other similar facilities; and
- realize value by opportunistically forming partnerships, participating in farm-out arrangements, joint operating agreements or other capital-efficient ventures to take advantage of our significant undeveloped acreage positions in the Cherokee Basin.

Black Warrior Basin

The Black Warrior Basin is one of the oldest and most prolific coalbed methane basins in the country. The multi-seam vertical wells in the basin range from 500 to 3,700 feet deep, with coal seams averaging a total of 25 to 30 feet of net pay per well. Coalbed methane wells are generally shallower and produce less gas than conventional natural gas wells, require pumping units to remove the water from the wells, which we refer to as dewatering, and require fracturing to enhance production. These wells also tend to start producing gas and water immediately upon completion, with production increasing as the well is dewatered. However, production rates from newly drilled and completed wells in the Black Warrior Basin do not always increase as the formation dewaters. Once dewatered, coalbed methane wells often demonstrate fairly constant production rates for up to five years and then production rates start declining. Wells in the area usually cost approximately $530,000 to drill and complete. Typical wells produce over a period of 20 to over 50 years and on average have less favorable economic characteristics than conventional gas wells. We generally own a 100% working interest (an approximate 75% average net revenue interest, calculated before the Torch Royalty NPI, or NPI, described in Item 1. Business Torch Royalty NPI) in the Black Warrior Basin, which had 493 producing natural gas wells as of December 31, 2008.

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

The Black Warrior Basin is located in western Tuscaloosa County and Pickens County, Alabama and encompasses a gross surface area of approximately 109 square miles. The field has been primarily developed on 80-acre spacing. The State of Alabama has approved either 40-acre or 80-acre spacing field-wide. We are currently developing our properties in the field on both 40- and 80-acre spacing.

The field has seven compressor stations with 800-1,200 horsepower compressors, approximately 170 miles of gas gathering lines (wells to header) and 25 miles of transportation lines (header to compressor). In addition, there are approximately 152 miles of water gathering pipes and 28 miles of water transportation pipes.

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

Our estimated proved reserves in the Black Warrior Basin at December 31, 2008 were approximately 111.6 Bcfe, approximately 77% of which were classified as proved developed.

Cherokee Basin

The Cherokee Basin is located in the Mid-Continent region in southern Kansas, northern Oklahoma, and western Missouri. It is the eighth largest coalbed methane basin in the United States and covers approximately 26,500 square miles. Production of coalbed methane gas has been ongoing in the basin since the late 1980s. The predominant production is natural gas produced from coals and shales. When commodity prices increased over the past few years, the attraction to these shallow long-lived unconventional resources increased.

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

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

Producing coalbed methane zones get deeper moving from east to west across the Cherokee Basin. Portions of Nowata County, Oklahoma produce from depths that range from about 700 feet to about 1,300 feet in depth. Wells in this area usually cost less than $170,000 to drill and complete. This is in contrast to coalbed methane producing zones in Osage County, Oklahoma that range from about 900 feet to about 2,700 feet in depth. Wells in this area usually vary in cost from $300,000 to in excess of $400,000 to drill and complete. Offsetting the lower drilling costs are the relatively low reserves and low daily production rates per well. Typical wells produce over a period of 20 to over 50 years and on average have less favorable economic characteristics than conventional gas wells.

At December 31, 2008, we own approximately 2,261 net producing wells in the Cherokee Basin. The gas coming from our producing wells is low pressure due to the shallow producing formations. Therefore, compression is needed to move the gas to point of sale. We operate in excess of 20 booster compressors and stations to get our natural gas to sales points owned by ONEOK Gas Gathering LLC, Scissortail Energy LLC, Enogex Gas Gathering LLC, Enogex LLC, and Southern Star Central Gas Pipeline. We operate a substantial portion of our production in the Cherokee Basin. We also own a 50% working interest in wells operated by Bullseye Operating L.L.C. Bullseye operates approximately 500 gross wells in Washington and Nowata Counties in Oklahoma and sells its production through the Cotton Valley producers cooperative, Cotton Valley Compression, L.L.C. Our average gross working interest in our Cherokee Basin properties is approximately 70%, with our average gross working interest in our operated properties being approximately 80% and our average gross working interest in our non-operated Cherokee Basin properties being approximately 50%.

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

Our estimated proved reserves in the Cherokee Basin at December 31, 2008 were approximately 115.7 Bcfe, approximately 59% of which were classified as proved developed.

Woodford Shale

The Woodford Shale is located in the Arkoma Basin in southern Oklahoma. We own 83 well bores, or 10 net producing wells, located in Coal and Hughes counties. This area is gas-rich and is characterized by multiple productive zones. The production of natural gas in the Woodford Shale comes from shale rock that has been stimulated through fracturing jobs after a horizontal well has been drilled. Woodford Shale wells are typically 6,000 to 11,000 feet deep and cost approximately $3.3 million on average to drill and complete with multiple fracs required. The gas-bearing shale section ranges from 120 to 200 feet thick. As of December 31, 2008, our 83 wells have an average gross working interest of 11.4% and a net revenue interest per well of 9.2%.

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Approximately 90% of the wells are operated by affiliates of Devon Energy Company (Devon) and Newfield Exploration Company (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, 2008 were approximately 5.1 Bcfe, all of which were classified as proved developed.

Proved Reserves

The following table reflects our estimates of net proved 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 natural gas reserves.

	As of December 31,		
Reserve data:	**2008**	**2007**	**2006**
Estimated net proved reserves:			
Oil and natural gas (Bcfe)	232.4	302.8	120.3
Proved developed reserves (Bcfe)	159.0	186.7	97.4
Proved undeveloped reserves (Bcfe)	73.4	116.1	22.9
Proved developed reserves as a percent of total reserves	68%	62%	81%
Standardized Measure (in millions)[(a)]	$ 228.9	$ 480.4	$ 120.2

(a) Standardized Measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation) without giving effect to non-property related expenses such as general and administrative expenses and debt service or to depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. Our Standardized Measure does not include future income taxes because we are not subject to income taxes. Standardized Measure does not give effect to derivative transactions and excludes reserves attributable to the NPI.

At December 31, 2008, 2007, and 2006, 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 2008 proved reserves to prepare our financial statements. We used internal estimates of our proved reserves to prepare our financial statements for 2007 and 2006. NSAI s estimates of our 2007 and 2006 proved reserves are materially consistent with our internal estimate.

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

The data in the above table 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 the reserves. The 10% discount factor used to calculate present value, which is required by

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Financial Accounting Standards Board (FASB) pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Oil and Natural Gas Prices

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

	Prices on January 1,		
Market Prices:	**2009**	**2008**	**2007**
Natural gas price NYMEX (Henry Hub)	$ 6.16	$ 7.13	$ 5.84
Natural gas price CenterPoint Energy Gas Transmission (East)	$ 4.46	$ 6.19	$ 5.51
Natural gas price Natural Gas Pipeline Company of America (Midcontinent)	$ 4.66	$ 6.17	$ 5.55
Natural gas price ONEOK Gas Transportation (Oklahoma)	$ 4.61	$ 6.36	$ 5.49
Natural gas price Panhandle Eastern Pipeline (Texas, Oklahoma)	$ 4.57	$ 6.21	$ 5.52
Natural gas price Southern Natural Gas Company (Louisiana)	$ 6.21	$ 7.26	$ 5.92
Natural gas price Southern Star Central Gas Pipeline (Texas, Oklahoma, Kansas)	$ 4.74	$ 6.20	$ 5.50
Oil price West Texas Intermediate Cushing	$ 44.60	$ 95.95	$ 60.85

We enter into derivative transactions in the form of hedging arrangements to reduce the impact of natural gas price volatility on our cash flow from operations. Currently, we use fixed price swaps and options to hedge New York Mercantile Exchange, or NYMEX , natural gas prices. We also use basis swaps to limit our exposure to differences between the NYMEX gas price and the price at the location where we sell our gas. By removing the price volatility from a significant portion of our natural gas production, we have mitigated, but not eliminated, the potential effects of fluctuating natural gas prices on our cash flow from operations for those periods. All of our derivative positions are outlined starting on page 69.

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Production and Price History

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

	Constellation Energy Partners LLC		
	For the year ended December 31, 2008	For the year ended December 31, 2007	For the year ended December 31, 2006
Net Production:			
Total production (MMcfe)	17,384	10,393	4,641
Average daily production (Mcfe/d)	47,497	28,474	12,715
Average Sales Prices:			
Price per Mcfe including hedges[(a)]	$ 9.39	$ 7.30	$ 7.95
Price per Mcfe excluding hedges	$ 8.13	$ 6.51	$ 7.43
Average Unit Costs Per Mcfe:			
Field operating expenses[(b)]	$ 2.57	$ 2.00	$ 1.94
Lease operating expenses	$ 2.09	$ 1.65	$ 1.56
Production taxes	$ 0.48	$ 0.35	$ 0.38
General and administrative expenses	$ 0.83	$ 0.88	$ 0.99
Depreciation, depletion and amortization[(c)]	$ 4.48	$ 2.23	$ 1.60

(a) Price per Mcfe including hedges includes realized and unrealized mark-to-market losses on derivative transactions that did not qualify for hedge accounting treatment.
(b) Field operating expenses include lease operating expenses and production taxes.
(c) Depreciation, depletion and amortization includes non-cash impairments of oil and natural gas assets. Excluding impairments, the 2008 cost per Mcfe was $3.01.

Productive Wells

The following table sets forth information at December 31, 2008 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Natural Gas December 31, 2008		Oil December 31, 2008	
	Gross	Net	Gross	Net
Operated	2,357	2,301	134	134
Non-operated	659	317	23	12
Total	3,016	2,618	157	146

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Drilling Activity

The following table sets forth information with respect to wells drilled and completed by us during the years ended December 31, 2008, 2007 and 2006. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of oil or natural gas, regardless of whether they produce a reasonable rate of return. No exploratory wells were drilled during the years ended December 31, 2008, 2007 or 2006.

	Year Ended December 31, 2008	2007	2006	Wells in Progress as of December 31, 2008
Gross:				
Development				
Productive	130	102	31	38
Dry				
Recompletions	47	24		1
Total	177	126	31	39
Net:				
Development				
Productive	115	89	31	38
Dry				
Recompletions	43	21		1
Total	158	110	31	39

Development Costs

We drilled and completed 115 net wells during the year ended December 31, 2008. Those wells developed 10.7 Bcfe of natural gas previously categorized as proved undeveloped reserves or unproved reserves. We invested a total of $47.9 million in these and other activities on our properties.

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2008 relating to our leasehold acreage.

	Developed Acreage[a]		Undeveloped Acreage[b]	
	Gross[c]	Net[d]	Gross[c]	Net[d]
Total	252,299	243,147	107,531	102,307

This acreage includes areas leased under a concession agreement that we have with the Osage Nation in Osage County, Oklahoma, which provides us the exclusive right to lease up to approximately 560,000 acres within the Osage Nation. Our concession agreement with the Osage Nation is in four phases as follows: (i) Phase I (four year term of January 1, 2005 through December 31, 2008) wherein not less that 440 production wells shall be drilled and completed; (ii) Phase II (four year term of January 1, 2009 through December 31, 2012) wherein a cumulative of not less than 680 production wells shall be drilled and completed; (iii) Phase III (four year term of January 1, 2013 through December 31, 2016) wherein a cumulative of not less than 920 production wells shall be drilled and completed; and (iv) Phase IV (four year term of January 1, 2017 through December 21, 2020) wherein a cumulative of not less than 1,160 production wells shall be drilled and completed, such that not less than a total of 1,160 production wells shall be drilled in Phases I through IV. Generally, in addition to the drilling and completion of a producing well counting as a production well, the drilling of two dry holes are counted as one production well, a recompletion of an existing wellbore is counted as one production well, a

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horizontal well is counted as two production wells and a salt water disposal well is counted as one production well under the concession agreement (hereinafter production well credits). As of December 31, 2008, the end of Phase I, we believe we have earned approximately 702 production well credits and our leased acreage totaled approximately 115,041 acres. Generally, we have the right each year to elect to license up to a certain acreage for that year for a specified license payment, and a license must be obtained before we lease acreage. During the term of the concession agreement, however, we have the exclusive right to lease the acreage covered thereunder unless we notify the Osage Nation in writing that we have no intention to lease any particular acreage. If the drilling requirement for a particular phase is not met, we have the option to make a payment equal to the shortfall of wells required to be drilled multiplied by $50,000 per well in order to be deemed to have complied with the requirement for that phase. If the drilling requirement of particular phase were not met (either through drilling of production wells or payment as described above), the Osage Nation s sole remedy shall be the termination of the concession agreement at the expiration of the then current phase, provided that such termination shall have no effect upon our wells already drilled and the leases that we have acquired that are producing in paying quantities.

(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 (61%), Alabama (35%), and Kansas (4%). We have over 1,000 leases in the Black Warrior Basin on over 59,000 net acres. The typical oil and gas lease agreement covering our Black Warrior Basin properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on or pooled with the leased property. There are other burdens affecting certain of the leases in the form of overriding royalty interests and the NPI. On our properties in the Black Warrior Basin, we own a 100% working interest, or an approximate 75% net revenue interest, in substantially all our developed acreage. Depending on the location of a particular well, the total lease burden is generally 25%, generally corresponding to a 75% lease net revenue interest to us calculated before the NPI. In some instances, our lease net revenue interest may be as high as 83%. We have over 2,000 leases in the Cherokee Basin on over 130,000 net acres and a concession agreement with the Osage Nation in Osage County, Oklahoma which provides us the exclusive right to lease approximately 560,000 net acres within the Osage Nation until its expiration in 2020 or any earlier termination according to its terms. This concession is currently being continuously drilled to earn new acreage. The typical oil and gas lease agreement covering our other Cherokee Basin properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on or pooled with the leased property. In the Cherokee Basin, depending on the location of a particular well, the total lease burden on our operated properties is generally 20% corresponding to a 80% net revenue interest to us and on our non-operated properties is generally a 40% net revenue interest. We have no leasehold rights in the Woodford Shale.

Under the oil and gas lease agreements covering 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 these leases not currently held by production will expire by October 2010. Approximately 47%, 8% and 9% of our total net undeveloped acreage of 102,307 acres is held under leases that have remaining primary terms expiring in 2009, 2010 and 2011, respectively. Of these expiration amounts, approximately 87%, 83% and 96% relates to acreage leased under our concession agreement with the Osage Nation with terms expiring in 2009, 2010, and 2011, respectively. However, we have the exclusive right to acquire a new lease on any expired acreage under our concession agreement until its expiration in 2020 or any earlier termination according to its terms. Substantially all of the remaining expiring acreage in all three years is located in Alabama.

Operations

General

We are the operator of approximately 88% of the 2,763 net wells in which we own an interest. During 2008, our operations were managed by CEPM under the management services agreement that is described in Item 13. Certain Relationships and Related Transactions, and Manager Independence. Through the agreement, CEPM provided us with services in 2008 to operate our business including the management of our field employees, contract professional services firms, and other third party vendors who handle our operations and drilling functions.

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 Constellation, one of whom is our chief executive officer. Beginning in January 2009, our chief executive officer, chief operating officer, and president, our chief financial officer and treasurer, and our chief accounting officer and controller were transitioned from being provided by CEPM through the management services agreement to direct employees of one of the subsidiaries of the Company. For additional information, please refer to Transition of the Executive Management Team to CEP on page 87.

Project Management

In the Black Warrior Basin and in the Cherokee Basin, CEPM has responsibility for the overall operations of the field, directing field employees and contractors and executing the drilling program and other production enhancement opportunities. Field operations are conducted by employees of our subsidiaries. All other support services including geology, engineering, land administration and revenue accounting are provided by CEPM through the management services agreement. Employees and contractors of CEPM approve the design and the development, maintenance, recompletion and workover for all of the wells in the field. The ongoing drilling program is designed by us and implemented by CEPM and various contractors. We do not own drilling rigs or other oil field services equipment used for drilling wells on our properties.

Currently in the Black Warrior Basin, our site construction in the field for new wells is conducted by Sartain Contracting Company, and the drilling rigs are provided by and the wells are drilled by Pense Brothers Drilling Company, an established Black Warrior Basin drilling contractor. Cementing is conducted by Halliburton; Well Service, LLC provides well logging services; and Halliburton provides the design for, and executes upon, the well stimulation program. Through December 31, 2008, we used Ironhorse Energy LP (Ironhorse), an independent professional services company, to provide us with additional project management services for the operations of the Black Warrior Basin. We evaluate our service providers in the basin from time to time.

Currently in the Cherokee Basin, our construction and roustabout services are provided by Falcon Field Services, Inc. and HS Field Services, Inc. The drilling rigs are provided by and our vertical wells are drilled by Pense Brothers Drilling Company and our directional drilling is done by Scientific Drilling International. Cementing and stimulation services are conducted by Consolidated Oil Well Services, LLC and Maverick Stimulation Company. Rick s Tank Truck Service is our primary water hauling service. We evaluate our service providers in the basin from time to time.

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

Field Operations

Our day-to-day operations in the Black Warrior Basin were conducted by field employees of one of the Company s subsidiaries under the supervision of Ironhorse in 2008 and CEPM under the management services agreement in 2009. The field operations team has extensive experience in the Black Warrior Basin and has been operating the Black Warrior Basin since the early 1990s. This group is responsible for the operation of the existing production wells, pipelines, compressors and water handling facilities, as well as interaction with Alabama regulatory authorities with regard to permitting and compliance matters. In addition, they assist with the execution of the drilling and maintenance program and the management of the contractors responsible for the drilling and completion of these wells. We have a field office located in Buhl, Alabama.

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

Land Administration

Our lease positions are managed by CEPM under the management services agreement, with assistance from our employees and contract landmen. These 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 hired a land staff in our field offices in Alabama and Oklahoma. Our land administration function is currently led by a CCG employee in Houston.

Geology and Engineering

Our technical team for our assets in the Cherokee Basin is employed by CEP Mid-Continent LLC and is located in our technical office in Tulsa, Oklahoma. We are also provided geologic and engineering assistance by CEPM, with access to contract engineers, geologists and consultants who have experience in drilling and producing coalbed methane reserves. As a result, our project management team has the ability to draw from a base of experienced and capable talent to select drilling locations and completion approaches to improve productivity and generate and test new ideas to improve production and reserves from existing wells through the use of recompletions, optimizing compression and gathering systems.

Revenue Accounting

Our revenue accounting function for our Black Warrior Basin and Woodford Shale properties has been outsourced to Petroleum Financial, Inc., a Texas-based revenue accounting firm. It manages the cash flow associated with our interest in the oil and natural gas properties, including the payment of invoices, calculation and payment of royalties, calculation and payment of the Robinson s Bend NPI, receiving the revenues from gas sales and providing accounting information used to generate financial statements.

Our revenue accounting function for our Cherokee Basin properties has been outsourced to College Station Financial, a Texas-based revenue accounting firm that is a subsidiary of Schlumberger LTD, a supplier of technology, project management, and information solutions to the oil and gas industry. It manages the cash flow associated with our interest in the oil and natural gas properties, including the payment of invoices, calculation and payment of royalties, receiving the revenues from gas sales and providing accounting entries used to generate financial statements.

Marketing and Major Customers

Our marketing function is managed by CEPM under the management services agreement. We currently sell our natural gas produced in the Black Warrior basin to J.P. Morgan Ventures Energy Corporation and to Enterprise Alabama. We currently sell our natural gas produced in the Cherokee Basin to CCG, Scissortail Energy, LLC, Cotton Valley Compression, L.L.C., and ONEOK Energy Services Company, L.P. Our oil production is primarily purchased by Sunoco Inc. Our natural gas production in the Woodford Shale is marketed by the operators of the well bores. The sales arrangement with CCG has been approved by the Conflicts Committee of our Board of Managers.

Hedging Activity

Our hedging activities are managed by our employees. We have entered into derivative transactions with banks who participate in our reserve-based credit facilities. The derivative transactions are done to reduce our exposure to short-term fluctuations in natural gas prices and interest rates and to achieve more predictable cash flows. For a more detailed discussion of our derivative activities, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk in this Annual Report on Form 10-K.

Markets and Competition

We operate in a competitive environment for acquiring properties, marketing oil and natural gas and retaining trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a competitive environment with limited access to capital. There is substantial competition for the limited capital available for investment in the oil and natural gas industry. Neither Constellation nor any of its affiliates is restricted from competing with us. Constellation or its affiliates may acquire, invest in or dispose of E&P properties or other assets in the future without any obligation to offer us the opportunity to purchase or own interests in those assets.

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

Title to Properties

At the time we acquired our interests in our oil and natural gas properties, we obtained a title opinion or had performed a review on the most significant leases in the fields. As a result, title opinions or reviews have been obtained on a significant portion of our properties.

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In some instances, and as is customary in the oil and natural gas industry, we conducted only a cursory review of the title to certain properties on which we do not have proved reserves. To the extent title opinions or other investigations reflect title requirements on those properties, we are typically responsible for curing any material title matters at our expense. We generally will not commence drilling operations on a property until we have cured or waived any such title matters or deemed the title risk sufficiently mitigated to justify proceeding with operations on such property.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or will materially interfere with our use in the operation of our business. The Trust Wells in the Robinson s Bend Field in Alabama are subject to the NPI. For a more detailed discussion of the NPI, please read Item 1. Business Torch Royalty NPI . In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties to operate our business in all material respects as described in this Annual Report on Form 10-K.

Environmental Matters and Regulation

General

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

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

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

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

Waste Handling

The Resource Conservation and Recovery Act (RCRA) and comparable state statutes, 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

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requirements. Drilling fluids, produced waters and most other wastes associated with the exploration, development and production of oil and natural gas are currently regulated under RCRA s non-hazardous waste provisions. Certain of our operations are known to bring to the surface naturally occurring radioactive material (NORM) which is accumulated at our facilities and is subject to permitting and controls for storage, as well as requirements for proper disposal. We believe our operations are in substantial compliance with the radioactive materials license issued by the State of Alabama Department of Public Health to cover activities associated with NORM. Although we do not believe the current costs of managing any of our wastes are material under presently applicable laws, any future reclassification of natural gas exploration and production wastes as hazardous wastes, or more stringent regulation of NORM wastes, could increase our costs to manage and dispose of wastes.

Comprehensive Environmental Response, Compensation and Liability Act

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

We currently own, lease or operate numerous properties that have been used for coalbed methane 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 analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the Cherokee Basin, water is pumped from producing wells, collected, and injected into approved salt water disposal wells in the deeper Arbuckle formation. In the Black Warrior Basin, we maintain permits issued pursuant to the Clean Water Act that authorize the discharge of produced waters and similar wastewaters generated as a result of our operations, in accordance with effluent standards established by the Alabama Department of Environmental Management (ADEM). While we believe we are in substantial compliance with these permits and all other requirements of the Clean Water Act, we have several ponds used for the treatment and storage of wastewaters that were found to have leaked into the subsurface beneath the ponds at some time in the past in the Black Warrior Basin. ADEM is aware of these leaks. We are in the process of replacing the liners beneath these treatment ponds and, under the supervision of ADEM, monitoring for the presence of chlorides in the subsurface to better determine what cleanup measures, if any, may be required by the ADEM. Based on present information, we do not believe we will incur material costs or penalties in connection

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with this matter, but there can be no assurance that significant costs will not be incurred if future data reveals elevated levels of chlorides beneath the ponds.

Air Emissions

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

OSHA and Other Laws and Regulation

We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communications standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes 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 and with other OSHA and comparable requirements.

The Kyoto Protocol to the United Nations Framework Convention on Climate Change became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol. The United States Congress has not passed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country, and by the incoming Obama administration and by certain members of Congress, for legislation that requires reductions in 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. Our operations have not yet been impacted by these current state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions or increased taxes on greenhouse gas emissions would impact our business.

Our operations in the Black Warrior Basin in Alabama are subject to the rules and regulations of the State Oil and Gas Board of Alabama Governing Coalbed Methane Gas Operations and these rules and regulations are found in the State Oil and Gas Board of Alabama Administrative Code. Our operations in the Cherokee Basin and in the Woodford Shale in Oklahoma are subject to the rules and regulations of the Oklahoma Corporation Commission, Oil & Gas Conservation Division. Our operations in the Cherokee Basin 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 will not have a material adverse impact on our financial condition and results of operations. We have approximately $0.4 million accrued in our financial statements for our estimated exposure for environmental-related matters. We are not aware of any additional environmental issues or claims that will require material capital expenditures or that will otherwise have a material impact on our financial position or results of operations. However, we cannot predict how future environmental laws and regulations may impact our operations, and therefore cannot provide assurance that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial condition, results of operations or ability to make distributions to our unitholders.

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Employees

As of December 31, 2008, our subsidiaries, Robinson s Bend Operations II, LLC and CEP Mid-Continent LLC, had 102 full-time field employees. None of these employees is subject to a collective bargaining agreement.

Under the management services agreement, CEPM will provide or contract for other necessary services including land, engineering, regulatory, accounting, financial, and other disciplines as needed. We reimburse CEPM for expenses under this agreement. For additional information regarding the management services agreement, please refer to page 93 under Item 13. Certain Relationships and Related Transactions, and Manager Independence and to page 87 under Transition of the Executive Management Team to CEP.

Offices

We are headquartered in Baltimore, Maryland where we share office space with Constellation. We also share office space with Constellation in Houston, Texas, and maintain a technical office in Tulsa, Oklahoma. In addition, we have field offices located in Buhl, Alabama, Coffeyville, Kansas, Dewey, Oklahoma, and Skiatook, Oklahoma. We own the land and field office buildings in Alabama, Kansas, and Oklahoma.

Torch Royalty NPI

The NPI

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

Not all of our wells within the Robinson s Bend Field are subject to the NPI. As of December 31, 2008, we owned a working interest in 493 producing wells in the Robinson s Bend Field, of which 424 were subject to the NPI as follows:

- with respect to 393 wells, the lesser of (i) 95% of the net proceeds from such wells for the quarter and (ii) the net proceeds from the sale of 912.5 MMcfe of natural gas for the quarter; and

- with respect to the remaining 31 wells that are subject to the NPI as of December 31, 2008, and all wells drilled thereafter on leases subject to the NPI other than wells drilled to replace damaged or destroyed wells, 20% of the net proceeds from such wells for the quarter. Net proceeds is defined under the NPI as gross revenue from the sale of production attributable to the NPI less specified development, operating and other costs and taxes, in each case as calculated under the NPI documentation. After January 1, 2004, lease operating expenses and capital expenditures have also been deducted in calculating net proceeds under the NPI on the Black Warrior Basin production. If permitted deductions exceed the gross revenue from the sale of production attributable to the NPI, the Trust is not entitled to a payment in respect of the NPI, and such excess, plus interest on such excess, is deducted from gross revenue attributable to future production in respect of the NPI. Payment of the net proceeds, if any, attributable to the NPI is made quarterly. Between July 1, 2003 and December 31, 2005, deductible expenses exceeded gross proceeds attributable to the Trust Wells, resulting in a cumulative deficit of approximately $69,000. The deficit was eliminated as a result of net proceeds attributable to the Trust Wells in January 2006, and we made payments to the Trust in respect of the NPI of approximately $0.2 million in the aggregate for January through December 2006. No payments were made in 2008 or 2007.

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The Gas Purchase Contract

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

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

Termination of the Trust and Gas Purchase Contract

On January 29, 2008, the unitholders of the Torch Energy Royalty Trust voted to terminate the Trust and the trust agreement and authorized the Trustee to wind up, liquidate, and distribute the assets held by the Trust under the terms of the trust agreement. The gas purchase contract, by its terms, was also terminated on January 29, 2008 as a result of the termination of the Trust. With the gas purchase contract terminated, we are no longer obligated to sell gas produced from our interest in the Black Warrior Basin pursuant to the gas purchase contract. Notwithstanding the termination of the gas purchase contract, the NPI will continue to burden the Trust Wells, and it should continue to be calculated as if the gas purchase contract were still in effect, regardless of what proceeds may actually be received by us as the seller of the gas. Originally, the Trust indicated that it believed that the net profits interest would continue to be calculated as if the gas purchase contract was still in effect. The Trust, however, subsequently indicated that the documents creating the NPI were not clear as to this point. As a result, on January 25, 2008, Torch Royalty Company (Torch Royalty), Torch E&P Company (Torch E&P) and CEP (collectively, the Claimants) sent notice of a demand for arbitration before Judicial Arbitration and Mediation Services (JAMS) to Wilmington Trust Company, as Trustee (Trustee) for the Trust, and to Capital One, NA, as successor to Hibernia National Bank, as trustee for Torch Energy Louisiana Royalty Trust, pursuant to the operative dispute resolution provisions of the agreement governing the Trust, the NPI and the Conveyances (as defined below). The Claimants were working interest owners in certain oil and gas fields located in Texas, Louisiana and Alabama. The working interests owned by the other Claimants are similarly subject to net profit interests (the Other NPIs) that are also based on the gas purchase contract. In the arbitration demand, we and the other Claimants sought a declaratory judgment that the NPI payments as well as the payments owed in respect of the Other NPIs will continue to be calculated using the sharing arrangement under the gas purchase contract even though the Trust and the gas purchase contract have been terminated. In its response to the Claimant s arbitration demand, the Trustee took the position that the sharing arrangement under the gas purchase contract terminated upon the termination of that contract. In April 2008, Trust Venture Company, LLC (Trust

Venture) was permitted to intervene in the arbitration proceeding under an agreement whereby Trust Venture and its affiliates agreed to be bound by the formal award in the proceeding. On July 18, 2008, the arbitration panel issued its final award (the Final Award) which, among other things, found and concluded that the sharing arrangement and other pricing terms of the gas purchase contract will continue to control the amount owed to the holder of the NPI.

The Trust and Trust Venture filed a petition to vacate the Final Award (the Petition to Vacate) with the District Court of Harris County, Texas, 152nd Judicial District (the District Court) on October 16, 2008. The Claimants filed a motion to confirm the Final Award (the Motion to Confirm) with the District Court on November 5, 2008. On December 10, 2008, the District Court dismissed the Petition to Vacate and granted the Motion to Confirm, thus confirming the Final Award. The Company believes that any timely further appeal or request for other relief by the Trust and Trust Venture should have been filed by January 9, 2009. The Company is not aware of any filing having been made.

On January 8, 2009, the Company was served by Trust Venture, on behalf of the Trust, with a purported derivative action filed in Alabama state court demanding an audited statement of revenues and expenses associated with the NPI, alleging a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserting that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit seeks unspecified damages and an accounting of the NPI. On February 9, 2009, the Company filed a motion to dismiss the lawsuit and filed an arbitration proceeding against the Trust relating to the claims alleged in the lawsuit with JAMS. On February 12, 2009, Trust Venture requested a stay of the arbitration proceeding. On February 25, 2009, the Circuit Court of Tuscaloosa County, Alabama denied the Company s motion to dismiss the lawsuit and also denied Trust Venture s motion to stay the arbitration proceeding. The Company intends to defend itself vigorously with respect to the alleged claims. There can be no assurance as to the outcome or result of the lawsuit or the arbitration proceeding. The Company intends its forward-looking statements relating to the action to speak only as of the time of such statements and does not plan to update or revise them except to the extent that material information becomes available.

Water Gathering, Separation, and Disposal Costs

As a result of the termination of the Trust, certain water gathering, separation and disposal costs, which are a component of the NPI calculation, increased from $0.53 per barrel to $1.00 per barrel pursuant to the Water Gathering and Disposal Agreement dated August 9, 1990, as amended. The amounts of the water gathering, separation and disposal costs are set forth in the Water Gathering and Disposal Agreement, as amended.

Impact of Class D Interests

In order to address, to a limited extent, the risks of the potential adverse impact on our operating results from early termination, without the prior consent of our board of managers, of the sharing arrangement in respect of the calculation of amounts payable to the Trust for the NPI, Constellation Holdings, Inc. (CHI) contributed to us at the closing of our initial public offering $8.0 million for all of our Class D interests. This contribution will be returned to CHI in 24 special quarterly distributions over a period of approximately six years if the sharing arrangement remains in effect during that period. In connection with the initiation of the arbitration proceeding mentioned above and continuing with the initiation of the lawsuit mentioned above, all quarterly cash contributions with respect to the Class D interests were suspended beginning with the special quarterly cash distributions for the three months ending March 31, 2008. This suspension did not affect the special quarterly cash distribution paid to CHI, as holder of the Class D interests, on February 14, 2008 for the three months ended December 31, 2007. After the payment of the special quarterly distribution for the quarter ended December, 31, 2007, the remaining undistributed amount of the Class D interests is $6.7 million. If the amounts payable by us to the Trust are not calculated based on continued applicability of the sharing arrangement through December 31, 2012, unless such change is approved in advance by our board of managers and our conflicts committee, the following will occur: the Class D interest holder will cease receiving the special quarterly cash distributions; and the Class D interest holder will only receive the remaining undistributed amount of the original $8.0 million contribution under certain circumstances upon our liquidation. The effect of our retention and use of the unreturned amount is to provide us with cash that will mitigate, but may not eliminate, the adverse impact of our reduced revenues from the termination of the sharing arrangement. Based upon our estimated production as reflected in our reserve report and our SONAT Gas Daily price curve on January 28, 2009, we estimate that, if the sharing arrangement in respect of the Trust was terminated and certain water disposal costs applicable to the Trust Wells increase from $0.53 per barrel to $1.00 per barrel, the remaining $6.7 million contributed to us for the Class D interests would offset the resulting revenue shortfall through the third quarter of 2012, if production and prices were to remain constant throughout such period.

Available Information

Our internet address is *http://www.constellationenergypartners.com*. We make available free of charge on or through our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to the SEC. The SEC maintains an internet website that contains these reports at *http://www.sec.gov*. The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information concerning the operation of the Public Reference Room may be obtained by calling the SEC at (800) 723-0330.

Item 1A. Risk Factors

Risks Related to Our Business

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our financial condition or results of operations and, as a result, our ability to pay distributions to our unitholders.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, our drilling and producing operations may be curtailed, delayed or canceled 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; reductions in oil and natural gas prices; limitations in the market for oil and natural gas; adverse weather conditions; facility or equipment malfunctions; accidents; title problems; piping, casing or cement failures; compliance with environmental and other governmental requirements; unusual or unexpected geological formations; lost or damaged oilfield drillings and service tools; loss of drilling fluid circulation; formations with abnormal pressures; environmental hazards, such as gas leaks, oil spills, pipeline ruptures and discharges of toxic gases; fires or natural disasters; blowouts, craterings and explosions; and uncontrollable flows of natural gas or well fluids.

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

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage or the insurance companies from which we obtain insurance could become credit impaired and unable to pay our claims. The occurrence of an event that is not fully covered by insurance could adversely affect our business activities, financial condition, results of operations and our ability to make cash distributions to our unitholders.

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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.

With the support of CEPM under the management services agreement, we have specifically identified and scheduled drilling locations for our future multi-year drilling activities on our existing acreage in the Black Warrior Basin and in the Cherokee Basin. 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, 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 natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified, which could have a significant adverse effect on our financial condition and results of operations.

Unless we replace the reserves that we produce, our existing reserves and production will decline, which would adversely affect our cash from operations and our ability to make cash distributions to our unitholders.

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

Our production from our existing reserves will decline over time. The rate of decline of our reserves and production reflected in our reserve reports will change if production from our existing wells declines in a different manner than we have estimated and can change when we drill additional wells, make acquisitions and under other circumstances. The rate of decline may also be greater than we have estimated due to decreased capital spending. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition and results of operations.

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

No one can measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels and operating and development costs. In addition, in the early stages of a coalbed methane project, it is difficult to predict the production curve of a coalbed methane field. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may prove to be inaccurate. For 2008, an independent petroleum engineering firm prepared the estimates of proved oil and natural gas reserves included in our SEC filings. For 2007 and 2006, we prepared the estimates of proved oil and natural gas reserves included in our SEC filings, and

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such estimates are different from the estimates that may be determined by an independent petroleum engineering firm. Over time, our engineers may make material changes to reserve estimates taking into account the results of actual drilling and production. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, certain assumptions are made regarding future oil and natural gas prices, production levels and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. For example, if natural gas prices were to decline by $1.00 per Mcfe, then the Standardized Measure of our proved reserves as of December 31, 2008 would decrease from approximately $228.9 million to approximately $131.1 million. Our Standardized Measure is calculated using unhedged oil and natural gas prices and is determined in accordance with the rules and regulations of the SEC (except for the impact of income taxes as we are not a taxable entity). Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil and natural gas we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves.

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

- the supply of and demand for oil and natural gas;
- the actual prices we receive for oil and natural gas;
- our actual operating costs in producing oil and natural gas;
- the amount and timing of our capital expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor used when calculating our discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions.

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

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

We rely exclusively on sales of the oil and natural gas that we produce. Furthermore, all of our assets are located in Alabama, Kansas, and Oklahoma. Due to our lack of diversification in asset type and location, an adverse development in the oil and gas business or these geographic areas, would have a significantly greater impact on the price which we receive for our oil and natural gas, our results of operations, and cash available for distribution to our unitholders than if we maintained more diverse assets and locations.

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

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

Certain of our undeveloped leasehold acreage is subject to leases that may expire in the near future.

We hold natural gas leases that are still within their original lease term and are not currently held by production. Unless we establish commercial production on the properties subject to these leases, these leases will expire. If our leases expire in the Black Warrior Basin or in the Cherokee Basin, we will lose our right to develop the related properties.

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

Higher oil and natural gas prices generally increase the demand for drilling rigs, supplies, services, equipment and crews, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Over the past three years, we and other oil and natural gas companies have experienced higher drilling and operating costs. Even as commodity prices have decreased, the costs for oilfield services have not declined as rapidly as commodity prices. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues and cash available for distribution.

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

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough to be commercially viable after drilling, operating and other costs. If we drill future wells that we identify as dry holes, our drilling success rate would decline, and may materially harm our business.

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

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

Our acquisition activities will subject us to certain risks.

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

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

If our recently completed acquisitions or other potential acquisitions do not generate increases in available cash per unit, our ability to make cash distributions to our unitholders could materially decrease.

Risks Related to Financing and Credit Environment

Our reserve-based credit facilities have substantial restrictions and financial covenants and have periodic borrowing base redeterminations. Additionally, borrowings under our reserve-based credit facilities become a current liability at October 31, 2009 and mature at October 31, 2010. We may have difficulty maintaining our compliance with the financial covenants, including our required ratio of current assets to current liabilities of not less than 1.0 to 1.0, and our required ratio of Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0, our required ratio of debt to Adjusted EBITDA of not greater than 3.5 to 1.0, maintaining our total

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borrowing base at the current level of $265 million at future redeterminations, renewing or replacing our existing reserve-based credit facilities before they mature, or maintaining or obtaining additional credit at similar terms, which could adversely affect our operations and our ability to pay distributions to our unitholders.

We depend on our reserve-based credit facilities for future capital needs and to fund a portion of our distributions. The reserve-based credit facilities restrict 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 facilities could result in a default under the facilities, which could cause all of our existing indebtedness to become immediately due and payable. Each of the following is an event of default:

- failure to pay any principal when due or any interest, fees or other amount prior to the expiration of certain grace periods;
- a representation or warranty made under the loan documents or in any report or other instrument furnished thereunder is incorrect when made;
- failure to perform or otherwise comply with the covenants in the credit facility or other loan documents, subject, in certain instances, to certain grace periods, which include covenants that:
  - Constellation and its affiliates maintain the right to elect our Class A managers; and
  - we obtain the approval of the administrative agent (such approval not to be unreasonably withheld or delayed) of any management services plan upon the termination of the management services agreement with CEPM;
- any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or our subsidiaries;
- 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;
- 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; and
- a change of control, generally defined as the first date on which both of the following two conditions occur: (i) a decrease by Constellation Energy Partners Holdings, LLC (CEPH) and CEPM of their combined ownership of our outstanding membership interests to less than 20%, and (ii) the ownership by any person (other than a wholly-owned subsidiary of Constellation) of more than 35% of our outstanding membership interests.

Our reserve-based credit facilities mature in October 2010 and, as a result, amounts due under the facilities are scheduled to become a current liability in October 2009. We may not be able to renew or replace the facilities at similar borrowing costs, terms, covenants, restrictions, or borrowing base, or with similar debt issue costs.

The reserve-based credit facilities limit the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. The 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, together with, among other things, the oil and natural gas prices existing at the time. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the reserve-based credit facilities. Any increase in the borrowing base requires the consent of all the

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lenders. Outstanding borrowings in excess of the borrowing base must be repaid immediately, 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 facilities.

The reserve-based credit facilities contain 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 the Company and its subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the facilities and we would be in default under the facilities, which could cause all of our existing indebtedness to become immediately due and payable.

Our reserve-based credit facilities may restrict us from borrowing to pay distributions on our outstanding units.

We have the ability to borrow under our credit facilities to pay distributions to unitholders as long as no event of default exists and provided that no distribution to unitholders may be made if the borrowings outstanding under our credit facilities exceeds 90% of the borrowing base. At February 20, 2009, our borrowings outstanding were at 83% of the total borrowing base under the facilities. We anticipate that if, at the time of any distribution, our borrowings equal or exceed 90% of the then-specified borrowing base, our ability to pay distributions to our unitholders in any such quarter will be solely dependent on our ability to generate sufficient cash from our operations.

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

Our operations are affected by local, national and worldwide economic conditions. The consequences of an economic recession and the current credit crisis may include a lower level of economic activity and increased volatility in energy prices. A lower level of economic activity might result in a decline in energy consumption and lower market prices for oil and natural gas, which may adversely affect our financial results and our ability to fund capital expenditures or to increase or maintain our distribution rate.

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

The disruptions in capital and credit markets may also result in higher LIBOR interest rates on our reserve-based credit facilities, which would increase our interest expense and adversely affect our financial results. Additionally, lower market prices for oil and natural gas may result in a decrease in our borrowing base under our reserve-based credit facilities at the time of a borrowing base redetermination. Because of the credit crisis, the lenders in our reserve-based credit facilities may not be able to fund our borrowing requests, which would negatively impact our ability to operate our business.

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

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

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

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

We are exposed to risks of loss in the event of nonperformance by our customers and by the counterparties to our hedging arrangements. Some of our customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our customers and/or counterparties could reduce our ability to make distributions to our unitholders.

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 natural gas they purchase from us and are not replaced by new customers, our revenues and cash available for distribution could decline.

We currently sell our natural gas produced in the Black Warrior basin to J.P. Morgan Ventures Energy Corporation and to Enterprise Alabama. We currently sell our natural gas produced in the Cherokee Basin to CCG, Scissortail Energy, LLC, Cotton Valley Compression, L.L.C., and ONEOK Energy Services Company, L.P. Our oil production is primarily purchased by Sunoco Inc. Our natural gas production in the Woodford Shale is marketed by the operators of the well bores. To the extent these or other customers reduce the volumes of oil and natural gas that they purchase from us and are not replaced by new customers, our revenues and cash available for distribution could decline.

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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 facilities or otherwise. Our future indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- covenants contained in our existing and future credit and debt instruments will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- we will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to unitholders; and
- our debt level will make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

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

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

Our business requires a significant amount of capital expenditures to maintain and grow production levels. Commodity prices have historically been volatile and we cannot predict the prices we will be able to realize for our production in the future. As a result, we may borrow significant amounts under our reserve-based credit facilities in the future to enable us to pay quarterly distributions. Significant declines in our production or significant declines in realized oil and natural gas prices for prolonged periods and resulting decreases in our borrowing base may force us to reduce or suspend distributions to our unitholders.

When we borrow to pay distributions, we are distributing more cash than we are generating from our operations on a current basis. This means that we are using a portion of our borrowing capacity under our reserve-based credit facilities to pay distributions rather than to maintain or expand our operations. If we use borrowings under our reserve-based credit facilities to pay distributions for an extended period of time rather than toward funding capital expenditures and other matters relating to our operations, we may be unable to support or grow our business. Such a curtailment of our business activities, combined with our payment of principal and interest on indebtedness incurred to pay distributions, will reduce our cash available for distribution on our units. If we borrow to pay distributions during periods of low commodity prices and commodity prices remain low, we may have to reduce our distribution in order to avoid excessive leverage.

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

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

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

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based 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 would also increase the borrowing costs associated with our reserve-based credit facilities. If our borrowing costs were to increase, our interest payments on our debt would increase which would reduce the amount of cash available for distribution to unitholders.

Risks Related to Our Distribution to Unitholders

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 or other 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.

We may not have sufficient cash from operations to pay our quarterly distributions following establishment of cash reserves and payment of fees and expenses, and future distributions to our unitholders may fluctuate from quarter to quarter or be suspended.

We may not have sufficient cash flow from operations each quarter to pay distributions at the quarterly distribution amount of $0.13 per common unit for the fourth quarter of 2008 following establishment of cash reserves and payment of fees and expenses. The amount of cash we can distribute on our common units 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, including reimbursements to CEPM under the management services agreement; the costs we incur to acquire E&P properties; whether we are able to continue our development activities at economically attractive costs; the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon; and the level of our capital expenditures.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including: the borrowing bases under our reserve-based credit facilities; our ability to make working capital borrowings under our reserve-based credit facilities to pay distributions; our debt service requirements and covenants and restrictions on distributions contained in our reserve-based credit facilities; fluctuations in our working capital needs; the timing and collectability of receivables; prevailing economic conditions; the amount of our estimated maintenance capital expenditures; and the amount of cash reserves established by our board of managers for the proper conduct of our business, including the maintenance of our asset base and the payment of future cash distributions on our Class A and common units, any management incentive interests and Class D interests. As a result of these factors, the amount of cash we distribute in any quarter to our unitholders may fluctuate significantly from quarter to quarter and may be significantly less than the quarterly distribution amount for the fourth quarter 2008. If we do not achieve our expected operational results or cannot borrow the amounts needed, we may not be able to pay the full, or any, amount of the quarterly distribution, in which event the market price of our common units may decline substantially.

Oil and natural gas prices are very volatile, and if commodity prices decline significantly for a temporary or prolonged period, our cash from operations will decline and we may have to lower our quarterly distribution or may not be able to pay distributions at all.

Our revenue, profitability and cash flow depend upon the prices and demand for oil and natural gas and a drop in prices can significantly affect our financial results and impede our growth. Changes in oil and natural gas prices have a significant impact on the value of our reserves and on our cash flow. In particular, declines in commodity prices will reduce the value of our reserves, our cash flow, our ability to borrow money or raise capital and our ability to pay distributions. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as: the domestic and foreign supply of and demand for oil and natural gas; the price and level of foreign imports of oil and natural gas; the level of consumer product demand; weather conditions; overall domestic and global economic conditions; political and economic conditions in oil and natural gas producing countries, including those in West Africa, 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; and the price and availability of alternative fuels.

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

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

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

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

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Our significant maintenance capital expenditures will reduce the amount of cash we have available for distribution to our unitholders. In addition, our actual maintenance capital expenditures will vary from quarter to quarter.

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

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

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

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of natural gas, our current intention is to hedge, subject to the terms of our reserve-based credit facilities, up to 80% 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, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our hedging activities are subject to the following risks:

- a counterparty may not perform its obligation under the applicable derivative instrument;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures.

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If we do not make acquisitions on economically acceptable terms, our future growth and ability to sustain or increase distributions will be limited.

Our ability to grow and to increase distributions to unitholders is partially dependent on our ability to make acquisitions that result in an increase in available cash per unit. We may be unable to make such acquisitions because we are:

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

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

Risks Related to Our Structure and Our Relationship with Constellation

Constellation and its affiliates own an interest in us through their ownership of our Class A and common units.

Constellation indirectly owns approximately 27% of the outstanding common units and 100% of the outstanding Class A units as of December 31, 2008. The percentages reflect common units that have been issued under our long-term incentive plan. CEPM, as the holder of all our Class A units, has the exclusive right to elect two members of our board of managers.

CEPH may sell common units in the future, which could reduce the market price of our outstanding common units.

As of December 31, 2008, CEPH controlled an aggregate of 5,918,894 common units. These units were registered for resale in January 2008 at the request of CEPH. If CEPH were to sell some or a substantial portion of its common units, it could reduce the market price of our outstanding common units.

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

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

Constellation s announcement that it intends to sell its upstream gas assets, which may include its ownership interests in us, could result in the loss of our sponsor, a reduction of services provided to us by Constellation under our management services agreement, or a termination of such agreement, and the loss of Constellation as a potential source for our growth.

Constellation s announcement of its plans to sell its upstream gas assets as market conditions allow may change its intent to remain our sponsor or to provide services to us under our management services agreement, which may be terminated by Constellation with six month s notice. In the event of any such reduction or termination, we will need to perform those services ourselves or find a replacement provider, both of which are likely to result in higher costs to us. If the management services agreement is terminated, we will also be required to present a plan to our bank group to manage our business under the covenants associated with our reserve-based credit facilities. Also in connection with the sale of the upstream assets, Constellation may reduce or completely divest its ownership interests in us. Although a sale of its ownership interests by itself is not considered a change of control under our reserve-based credit facilities, it could become one if another party acquires 35% of our outstanding units.

Constellation has been a source of growth for us in the past, and the termination of the management services agreement or the disposition of Constellation s ownership interests in us may result in the loss of future growth opportunities.

We have relied on third parties, including CEPM, for our management. If CEPM or these third parties fail to or inadequately perform, or if we cannot enter into other management contracts on satisfactory terms, our costs will increase and reduce our cash from operations and our ability to make cash distributions.

We have relied on third parties for our management. While our board of managers has the right and responsibility to manage our affairs, we rely on third parties to manage the day-to-day aspects of our business. We have entered into a management services agreement with CEPM, a wholly owned subsidiary of Constellation. CEPM provides us legal, accounting, audit, tax, financial and risk management services. CEPM also provides us with assistance in hedging our production and acquisition services in respect of opportunities for us to acquire long-lived, stable and proved oil and natural gas reserves.

Constellation and its affiliates have no obligation to present us with potential acquisitions, and, if they fail to do so, we will need to either seek acquisitions on our own or retain a third party to seek acquisitions on our behalf. Although we have substantial undeveloped acreage in Osage County, Oklahoma, in the long term, without further acquisitions, we may not be able to replace or grow our reserves, which would reduce our cash from operations and our ability to make cash distributions. In addition, although we may make acquisitions in areas where we can work with third-party operators who have technical development expertise and experience in the particular natural gas field in which we are acquiring an interest and who will hold a working interest in such properties, we may need to hire additional personnel to operate any properties acquired. Doing so will increase our costs and could adversely affect our cash from operations and our ability to make cash distributions.

Expense reimbursements due to CEPM under our management services agreement will reduce cash available for distribution to our unitholders.

Prior to making any distribution on the common units, we will reimburse CEPM for certain expenses that it incurs on our behalf pursuant to the management services agreement. These expenses include certain costs incurred on our behalf in performing accounting and financial, risk management and acquisition services, including costs for providing corporate staff and support services to us. CEPM charges us an allocated amount for services provided to us. This allocated cost basis is based on the percentage of time spent by personnel of CEPM and its affiliates on our matters and includes the compensation paid by CEPM and its affiliates to such persons and other overhead. The allocation of compensation expense for such persons will be determined based on a good faith estimate of the value of each such person s services performed on our business and affairs, subject to the periodic review and approval of our audit or conflicts committee. The reimbursement of expenses to CEPM could adversely affect our ability to pay cash distributions to our unitholders.

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

Two members of our board of managers are appointed by CEPM, the holder of our Class A units. As of February 20, 2009, one of the members appointed by CEPM is an officer of and is affiliated with Constellation.

The other member appointed by CEPM is our chief executive officer, chief operating officer, and president. In addition, one of our managers serves as a manager, director, officer or employee of Constellation or its other affiliates. Conflicts of interest may arise between us and our unitholders and members of our board of managers or our executive officers and Constellation and its affiliates, including CEPH and CEPM. These potential conflicts may relate to the divergent interests of these parties. Situations in which the interests of members of our board of managers or our executive officers and Constellation and its affiliates, including CEPH and CEPM, may differ from interests of owners of common units include, among others, the following situations:

- our limited liability company agreement gives our board of managers broad discretion in establishing cash reserves for the proper conduct of our business, which will affect the amount of cash available for distribution. For example, our board of managers will use its reasonable discretion to establish and maintain cash reserves sufficient to maintain our asset base;

- none of our limited liability company agreement, management services agreement nor any other agreement requires Constellation, CEPM or any of their affiliates to pursue a business strategy that favors us. Directors and officers of Constellation, CEPM and their subsidiaries (other than us) have a fiduciary duty while acting in the capacity as such a director or officer of Constellation, CEPM or such subsidiary to make decisions in the best interests of the Constellation stockholders, which may be contrary to our best interests;

- upon our request, CEPM, under the management services agreement, will recommend to our board of managers the timing and extent of our drilling program and related capital expenditures, asset purchases and sales, and financing alternatives (whether borrowings, issuances of additional limited liability company interests or a combination of the foregoing) and reserve adjustments, all of which will affect the amount of cash that we distribute to our unitholders;

- CEPM may provide us with opportunities for the acquisition of oil and natural gas reserves, however, neither Constellation nor CEPM has any obligation to provide us with such opportunities and CEPM may have no opportunities to present to us;

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

- one of our managers is not being compensated by us; instead, he is being compensated by Constellation for serving as an officer or employee of Constellation;

- we may rely on CEPM and its affiliates to assist us in implementing our hedging policy;

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

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

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

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

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

Our limited liability company agreement prohibits a unitholder (other than CEPM, CEPH and their affiliates) who acquires 15% or more of our common units without the approval of our board of managers from engaging in a business combination with us for three years. This provision could discourage a change of control that our unitholders may favor, which could negatively affect the price of our common units.

Our limited liability company agreement effectively adopts Section 203 of the Delaware General Corporation Law (the DGCL). Section 203 of the DGCL as it applies to us prevents an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in business combinations with us for three years following the time such person becomes an interested unitholder. Section 203 broadly defines business combination to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. This provision of our limited liability company agreement could have an anti-takeover effect with respect to transactions not approved in advance by our board of managers, including discouraging takeover attempts that might result in a premium over the market price for our common units.

Our reserve-based credit facilities have restrictive covenants related to our relationship with Constellation. We have no control over Constellation s actions related to selling their units or terminating the management services agreement. If these events occur, we may have an event of default under our reserve-based credit facilities.

Our reserve-based credit facilities contain provisions related to our relationship with Constellation. Each of the following is an event of default:

- failure to perform or otherwise comply with the covenants in the credit facility or other loan documents, subject, in certain instances, to certain grace periods, which include covenants that:
  - Constellation and its affiliates maintain the right to elect our Class A managers; and
  - we obtain the approval of the administrative agent (such approval not to be unreasonably withheld or delayed) of any management services plan upon the termination of the management services agreement with CEPM;
- a change of control, generally defined as the first date on which both of the following two conditions occur: (i) a decrease by Constellation Energy Partners Holdings, LLC (CEPH) and CEPM of their combined ownership of our outstanding membership interests to less than 20%, and (ii) the ownership by any person (other than a wholly-owned subsidiary of Constellation) of more than 35% of our outstanding membership interests.

The actions of Constellation with respect to its ownership of our units and the provision of services under the management services agreement, over which we have no control, may result in an event of default under our credit facilities. If an event of default occurs, this may cause all of our existing indebtedness to be immediately due and payable.

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

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

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

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

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

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

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

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

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

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

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

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 18-607 of the Delaware Revised Limited Liability Company Act (the Delaware Act), we may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, members or unitholders who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited liability company for the distribution amount. A purchaser of common units who becomes a member or unitholder is liable for the obligations of the transferring member to make contributions to the limited liability company that are known to such purchaser of units at the time it became a member and for unknown obligations if the liabilities could be determined from our limited liability company agreement.

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

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

- changes in securities analysts recommendations and their estimates of our financial performance;
- the public s reaction to our press releases, announcements and our filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of oil and natural gas companies and securities of publicly traded limited partnerships and limited liability companies;
- the sale of our units by significant unitholders or other market liquidity issues;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other oil and natural gas companies;
- variations in the amount of our quarterly cash distributions;
- future interest rates and expectations of inflation;
- future issuances and sales of our common units;

- changes in general conditions in the U.S. economy, financial markets or the oil and natural gas industry; and

- changes in our 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.

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Tax Risks to Unitholders

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

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate income tax rates, currently at a maximum rate of 35%, and would likely pay state income tax at varying rates. Distributions to unitholders would generally be taxed as corporate distributions, and no income, gain, loss, deduction or credit would flow through to the unitholders. Because a tax may be imposed on us as a corporation, our cash available for distribution to our unitholders could be reduced. Therefore, treatment of us as a corporation could result in a material reduction in the anticipated cash flow and after-tax return to our unitholders resulting in a substantial reduction in the value of our common units.

Current law or our business may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. For example, at the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships and limited liability companies to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to unitholders would be reduced. Our limited liability company agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the initial quarterly distribution amount and the Target Distribution amount (as defined in our limited liability company agreement) will be adjusted to reflect the impact of that law on us.

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress are considering substantive changes to the existing federal income tax laws that affect certain publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

Unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us.

Unitholders are required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

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

We will be considered to have terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. A constructive termination results in the closing of our taxable year for all unitholders and in the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. A constructive termination occurring on a date other than December 31 will result in us filing two tax returns (and unitholders receiving two Schedule K-1s) for one calendar year and the cost of the preparation of these returns will be borne by all unitholders.

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

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

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

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

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

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

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

If a unitholder sells any of his common units, he will recognize gain or loss equal to the difference between the amount realized and the tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income allocated for a common unit, which decreased the tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the tax basis in that common unit, even if the price received is less than the original cost. A substantial portion of the amount

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realized, whether or not representing gain, may be ordinary income to the unitholder. In addition, if the unitholder sells his units, he may incur a tax liability in excess of the amount of cash received from the sale.

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

In addition to federal income taxes, unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if the unitholder does not reside in any of those jurisdictions. Unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We currently do business and own assets in Alabama, Kansas, Maryland and Oklahoma. We are registered to do business in Texas. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all United States federal, foreign, state and local tax returns that may be required of such unitholder. In addition, if the unitholder sells his units, he may incur a tax liability in excess of the amount of cash received from the sale.

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

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

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

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

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

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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 cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

Risks Related to Environmental Issues and Compliance

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

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

We are subject to federal, state, tribal and local 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 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 through insurance or increased revenues, our ability to make 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. These include, for example:

- the federal Clean Air Act, related federal regulations and comparable state laws and regulations that impose obligations related to air emissions;
- the federal Clean Water Act, related federal regulations and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated waters;

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- the federal Resource Conservation and Recovery Act (RCRA) related federal regulations and comparable state laws and regulations that impose requirements for the handling and disposal of waste from our facilities; and

- the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA), also known as the Superfund law, and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal.

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

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Certain environmental statutes, including RCRA, CERCLA, the federal Oil Pollution Act and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of or otherwise released into the environment.

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

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

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

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

- several treatment ponds associated with the treatment and storage of produced waters and similar wastewaters have leaked into the subsurface and we are in the process of replacing the liners beneath these treatment ponds and, under the supervision of the Alabama Department of Environmental Management (ADEM), monitoring for the presence of contaminants in the subsurface to better determine what cleanup, if any, may be required.

If a problem occurs with respect to any one of these, it could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations.

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

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas exploration, production and transportation operations. These costs and liabilities could arise under a wide range of federal, state and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances that we handle. For instance, we must maintain permits and adhere to certain controls related to the storage and proper disposal of NORM that is produced periodically in connection with our natural gas drilling operations in the Black Warrior Basin. In addition, as a result of leaks from ponds used for

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the treatment and storage of produced waters and similar wastewaters from our operations, we are in the process of replacing pond liners and are also conducting subsurface monitoring for chlorides under the supervision of ADEM. We may incur additional expenses, which could be material, in the future if our monitoring activities reveal that any contaminants exist in the subsurface beneath the ponds, and the agency requires cleanup of any such contaminants.

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

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

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

We may face unanticipated water disposal costs.

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

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

Risks Related to the NPI

Since the Trust was terminated in January 2008, the gas purchase contract with the Trust also terminated. If it were determined that the payment by us to the Trust in respect of the NPI has ceased to be calculated under the sharing arrangement, or that the previous calculations of the NPI payments were incorrect, our royalty obligations under the NPI could increase, which could adversely affect our results of operations and our ability to pay cash distributions.

The gas purchase contract with TEMI, including the portion assigned to us, was terminated in January 2008 upon the termination of the Trust. The royalty payment owed by us under the NPI is calculated based in part on gross proceeds as that term is defined in the gas purchase contract. There is a sharing arrangement under the gas purchase contract that permits us, as gas purchaser, to retain any excess of the market price we receive for production from the Trust Wells over the price under the sharing arrangement. This price under the sharing arrangement is equal to the sum of the sharing price set forth in the gas purchase contract, plus 50% of the amount by which 97% of the applicable spot index price exceeds the sharing price. Despite increases in recent years in the spot price for natural gas, this sharing arrangement has had the effect of keeping the royalty payments to the Trust in respect of the NPI significantly lower than the prevailing market price. Notwithstanding the termination of the gas purchase contract, the NPI will continue to burden the Trust Wells, and it should continue to be calculated as if the gas purchase contract were still in effect, regardless of what proceeds may actually be received by us as the seller of the gas.

In our first arbitration proceeding with the Torch Energy Royalty Trust, the arbitration panel issued a final award which found and concluded that the sharing arrangement and other pricing terms of the gas purchase contract will continue to control the amount owed to the holder of the NPI. Nevertheless, we have now been sued as to the prior calculations of the NPI, and we have filed a second arbitration proceeding against the Trust with respect to such calculations, and the results of these proceedings could adversely affect our results of operations and our ability to pay cash distributions.

Based upon our estimated production as reflected in our reserve report and our SONAT Gas Daily price curve on January 28, 2009, we estimate that, if the sharing arrangement in respect of the Trust was terminated and certain water disposal costs applicable to the Trust Wells increase from $0.53 per barrel to $1.00 per barrel, the remaining $6.7 million contributed to us for the Class D interests would offset the resulting revenue shortfall only through the third quarter 2012, if production and prices were to remain constant throughout such period.

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

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

Assuming the sharing arrangement does not terminate, the gas purchase contract on which the NPI is based contains a sharing arrangement in the event the applicable spot index price for natural gas exceeds the sharing price, as calculated under the gas purchase contract. If the applicable spot index price for natural gas falls below the sharing price, it would have the effect of reducing the revenue we retain upon resale of the gas produced from the Trust Wells and could adversely affect our financial condition and results of operations and, as a result, our ability to pay cash distributions.

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

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Forward-Looking Statements

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

- the volatility of realized oil and natural gas prices;
- the conditions of the capital markets, inflation, interest rates, availability of credit facilities to support business requirements, liquidity, and general economic conditions;
- the discovery, estimation, development and replacement of oil and natural gas reserves;
- our business, financial, and operational strategy;
- our drilling locations;
- technology;
- our cash flow, liquidity and financial position;
- the amount of our cash distribution;
- the impact from any termination of the Robinson s Bend sharing arrangement;
- our hedging program and our derivative positions;
- our production volumes;
- our lease operating expenses, general and administrative costs and finding and development costs;
- the availability of drilling and production equipment, labor and other services;
- our future operating results;
- our prospect development and property acquisitions;

- the marketing of oil and natural gas;
- competition in the oil and natural gas industry;
- the impact of the current global credit crisis and economic recession;
- the impact of weather and the occurrence of natural disasters such as fires, floods, hurricanes, tornados, earthquakes, snow and ice storms and other catastrophic events and natural disasters;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas producing countries;
- support from our sponsor or a change in our sponsor; and
- our strategic plans, objectives, expectations, forecasts, budgets, estimates and intentions for future operations.

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

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

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

Our obligations under our credit facilities are secured by mortgages on our natural gas properties, as well as a pledge of all ownership interests in our subsidiaries. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Financing Activities Credit Facility , in this Annual Report on Form 10-K for additional information concerning our credit facility.

Item 3. Legal Proceedings

Termination of the Trust and Related Litigation

On January 29, 2008, the unitholders of the Torch Energy Royalty Trust voted to terminate the Trust and authorized the Trustee to wind up, liquidate, and distribute the assets held by the Trust under the terms of the trust agreement. As discussed in Item 1. Business on page 1 and Item 1A. Risk Factors on page 18, we are involved in litigation related to the calculation of the NPI held by the Trust in the Robinson s Bend Field in Alabama.

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

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

Our annual meeting of common unitholders was held November 3, 2008. At the meeting, the following matters were voted upon:

Class B managers nominated and reelected to serve for a term to expire in 2009 and until their successors are duly elected and qualified as follows:

	Common Units Votes For	Common Units Withheld
Richard H. Bachmann	16,216,769	278,146
Richard S. Langdon	16,216,869	278,046
John N. Seitz	16,216,369	278,546

The ratification of PricewaterhouseCoopers LLP as independent registered public accounting firm for 2008 was approved. With respect to common unitholders, the number of affirmative votes cast was 16,462,083, the number of votes cast against was 15,820, and the number of abstentions was 17,012.

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PART II

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

Our common units are listed on the NYSE Arca under the symbol CEP. Our units began trading on November 15, 2006, in connection with our initial public offering. On February 20, 2009, there were 21,938,342 common units outstanding and approximately 6,250 unitholders. On February 20, 2009, the market price for our common units was $2.28 per unit, resulting in an aggregate market value of units held by non-affiliates of approximately $36.5 million. The following table presents the high and low sales price for our common units during the periods indicated.

	Common Stock	
	High	Low
2008		
First Quarter	$ 31.60	$ 15.84
Second Quarter	$ 23.07	$ 17.20
Third Quarter	$ 20.59	$ 8.70
Fourth Quarter	$ 10.71	$ 2.46
2007		
First Quarter	$ 35.93	$ 23.90
Second Quarter	$ 41.25	$ 30.90
Third Quarter	$ 50.74	$ 33.00
Fourth Quarter	$ 42.73	$ 30.77
2006		
Fourth Quarter	$ 25.90	$ 21.00

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

	Cash Distributions		
	Per unit	Record date	Payment date
2008			
First Quarter	$ 0.5625	May 8, 2008	May 15, 2008
Second Quarter	$ 0.5625	August 7, 2008	August 14, 2008
Third Quarter	$ 0.5625	November 7, 2008	November 14, 2008
Fourth Quarter	$ 0.1300	February 7, 2009	February 13, 2009
2007			
First Quarter	$ 0.4625	May 8, 2007	May 15, 2007
Second Quarter	$ 0.4625	August 7, 2007	August 14, 2007
Third Quarter	$ 0.5625	November 7, 2007	November 14, 2007
Fourth Quarter	$ 0.5625	February 7, 2008	February 14, 2008
2006			
Fourth Quarter	$ 0.2111	February 7, 2007	February 14, 2007

Our limited liability company agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ended December 31, 2006, we distribute all of our available cash to unitholders of record on the applicable record date. Available cash generally means, for any quarter ending prior to liquidation:

(a) the sum of:

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

(ii) all additional cash and cash equivalents of the Company and its subsidiaries (or the Company s proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly-owned) 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 the Company s 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 the Company and its 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 the Company or any of its subsidiaries is a party or by which it is bound or its assets are subject; or

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

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

Private Placements

Transactions in 2007

In September 2007, we sold 2,470,592 common units representing Class B limited liability company interests in a private placement which generated proceeds of approximately $105 million. On October 12, 2007, a special meeting of CEP s common unitholders was held. At this meeting, the common unitholders approved the conversion of all outstanding Class F units into common units. As a result of the approval, all 3,371,219 of the Company s outstanding Class F units have been canceled and the same number of common units has been issued to the former holders of the Class F units. To facilitate the conversion, the common unitholders approved both a change in the terms of the Company s Class F units to provide that each Class F unit is convertible into the Company s common units, and the issuance of additional common units upon the conversion of the Class F units.

In July 2007, we sold 3,371,219 Class F units representing limited liability company interests and 2,664,998 common units representing Class B limited liability company interests in a private placement which generated proceeds of approximately $210 million.

In April 2007, we sold 90,376 Class E units representing limited liability company interests and 2,207,684 common units representing Class B limited liability company interests in a private placement for an aggregate purchase price of approximately $60 million. On June 26, 2007, a special meeting of CEP s common unitholders was held. At this meeting, the common unitholders approved the conversion of all outstanding Class E units into common units. As a result of the approval, all 90,376 of the Company s outstanding Class E units have been canceled and the same number of common units have been issued to the former holders of the Class E units. To facilitate the conversion, the common unitholders approved both a change in the terms of the Company s Class E units to provide that each Class E unit is convertible into the Company s common units, and the issuance of additional common units upon the conversion of the Class E units.

The units in each private placement were sold to certain unaffiliated third party investors. The offerings were exempt from registration under Section 4(2) of the Securities Act because the transactions did not involve a public offering.

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Transaction at Formation

In connection with our formation in February 2005, we issued to CCG in exchange for $100 a membership interest representing the right to receive an aggregate 100% of our distributions. The offering was exempt from registration under Section 4(2) of the Securities Act because the transaction did not involve a public offering.

Common Unit Performance Graphs

The graph below compares CEP s cumulative total unitholder return on its common units from November 15, 2006, through December 31, 2008, with the cumulative total returns of the Russell 2000 index, the Alerian MLP Index, the Dow Jones US Exploration & Production index, and a customized peer group of eight companies that includes: Atlas Energy Resources LLC, Breitburn Energy Partners L.P., Encore Energy Partners LP, EV Energy Partners L.P., Legacy Reserves LP, Linn Energy, LLC, Quest Energy Partners, L.P., and Vanguard Natural Resources, LLC . An investment of $100 (with reinvestment of all dividends) is assumed to have been made in the company s common stock, in each index and in the peer group on November 15, 2006, and its relative performance is tracked through December 31, 2008.

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Item 6. Selected Financial Data

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

We were formed in February 2005 and had no principal operations prior to the completion of a $161.1 million acquisition of natural gas reserves and equipment from Everlast on June 13, 2005. The historical financial data for the period from January 1, 2005 through June 12, 2005 and the year ended December 31, 2004 have been derived from Everlast s audited historical financial statements. Initially, our only operations were in the Black Warrior Basin, as were Everlast s. During each of the last three years, our properties in the Black Warrior Basin were wholly-owned by us or Everlast. Our acquisition from Everlast resulted in a new basis for our properties in the Black Warrior Basin for accounting purposes. In addition, new management, operating and accounting policies, and estimates were put into place after our acquisition from Everlast. Though the financial statements reflect the operation of the same properties in the Black Warrior Basin, due to these differences, the financial statements for the periods prior to and after our purchase of our properties in the Black Warrior Basin are not comparable. For that purpose, a black line has been placed between our and Everlast s financial statements. Our historical results of operations and period-to-period comparisons of results and certain financial data prior to and after our acquisition of our properties in the Black Warrior Basin from Everlast may not be indicative of future results.

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

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

	Successor Constellation Energy Partners LLC				Predecessor Everlast	
	For the year ended December 31, 2008	For the year ended December 31, 2007	For the year ended December 31, 2006	For the period from February 7, 2005 (inception) to December 31, 2005	For the period from January 1, 2005 to June 12, 2005	For the year ended December 31, 2004
			(in 000 s)			
Statement of Operations Data:						
Revenues:						
Oil and gas sales	$ 141,863	$ 82,725	$ 36,917	$ 25,957	$ 12,882	$ 27,494
Gain/(loss) from mark-to-market activities	21,376	(6,856)			(15,313)	(9,107)
Total revenues	163,239	75,869	36,917	25,957	(2,431)	18,387
Operating expenses:						
Lease operating expenses	36,257	17,141	7,234	4,175	2,769	5,270
Cost of sales	7,261	1,788				
Production taxes	8,398	3,646	1,783	1,400	676	1,479
General and administrative	14,412	9,109	4,573	4,184	594	2,706
Depreciation, depletion and amortization	77,919	23,190	7,444	4,176	1,683	3,719
Accretion expense	411	312	141	78	46	86
(Gain)/loss on asset sale	(301)	86				
Total operating expenses	144,357	55,272	21,175	14,013	5,768	13,260
Other expenses/(income):						
Interest expense	12,167	6,930	221	3	2,437	3,028
Interest income	(350)	(465)	(468)			
Other (income) expense	(203)	(109)				
Total other expenses/(income)	11,614	6,356	(247)	3	2,437	3,028
Total expenses	155,971	61,628	20,928	14,016	8,205	16,288
Net income	$ 7,268	$ 14,241	$ 15,989	$ 11,941	$ (10,636)	$ 2,099
Earnings per unit						
Basic	$ 0.33	$ 0.87	$ 1.41	$ 1.05		
Diluted	$ 0.33	$ 0.87	$ 1.41	$ 1.05		
Distributions declared and paid per unit	$ 2.25	$ 1.6986	$	$		

Other Financial Information (unaudited):						
Adjusted EBITDA	$ 74,871	$ 52,520	$ 23,025	$ 16,198	$ 8,795	$ 14,738

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	Successor Constellation Energy Partners LLC				Predecessor Everlast	
	For the year ended December 31, 2008	For the year ended December 31, 2007	For the year ended December 31, 2006	For the period from February 7, 2005 (inception) to December 31, 2005	For the period from January 1, 2005 to June 12, 2005	For the year ended December 31, 2004
			(in 000 s)			
Balance Sheet Data:						
Cash and cash equivalents	$ 6,255	$ 18,689	$ 7,485	$ 14,831		$ 2,012
Other current assets	45,976	27,184	18,602	6,097		4,562
Oil and natural gas properties, net of accumulated depreciation, depletion and amortization	662,519	643,653	171,639	165,211		52,531
Other assets	44,099	17,129	5,971			1,579
Total assets	$ 758,849	$ 706,655	$ 203,697	$ 186,139		$ 60,684
Current liabilities	$ 19,506	$ 20,551	$ 9,007	$ 13,895		$ 4,482
Debt	212,500	153,000	22,000	63		67,500
Other long-term liabilities	6,754	16,702	2,730	3,014		3,314
Class D interests	6,667	7,000	8,000			
Members equity:						
Common members equity	463,295	505,178	148,847	169,167		(14,612)
Accumulated other comprehensive income	50,127	4,224	13,113			
Total members equity	513,422	509,402	161,960	169,167		(14,612)
Total liabilities and members equity (deficit)	$ 758,849	$ 706,655	$ 203,697	$ 186,139		$ 60,684
Cash Flow Data:						
Net cash provided by operating activities	$ 75,632	$ 42,499	$ 14,067	$ 23,313	$ 6,639	$ 4,906
Net cash used in investing activities	(95,008)	(502,533)	(25,429)	(147,237)	(4,203)	(6,997)
Net cash provided by financing activities	6,942	471,238	4,016	138,755	(2,500)	1,540
Development of natural gas properties	(47,897)	(23,645)	(13,224)	(8,286)	(4,000)	(5,680)

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Non-GAAP Financial Measure Adjusted EBITDA

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

- interest (income) expense;
- depreciation, depletion and amortization;
- write-off of deferred financing fees;
- impairment of long-lived assets;
- (gain) loss on sale of assets;
- (gain) loss from equity investment;
- long-term incentive plan;
- accretion of asset retirement obligation;
- unrealized (gain) loss on natural gas derivatives; and
- realized loss (gain) on cancelled natural gas derivatives.

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 cash distributions we 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 an increase in our quarterly distribution rates. Adjusted EBITDA is also used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts and others to assess:

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

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

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

	Successor Constellation Energy Partners LLC				Predecessor Everlast Energy LLC	
	For the year ended December 31, 2008	For the year ended December 31, 2007 (In 000 s)	For the year ended December 31, 2006	For the period from February 7, 2005 (inception) to December 31, 2005	For the Period from January 1, 2005 to June 12, 2005	For the year ended December 31, 2004
Reconciliation of Net Income to Adjusted EBITDA:						
Net income	$ 7,268	$ 14,241	$ 15,989	$ 11,941	$ (10,636)	$ 2,099
Adjusted by:						
Interest expense/(income), net[(a)]	11,817	6,465	(247)	3	2,437	3,028
Depreciation, depletion and amortization	77,919	23,190	7,444	4,176	1,683	3,719
Accretion of asset retirement obligation	411	312	141	78	46	86
(Gain)/loss on sale of asset	(301)	86				
(Gain)/loss on mark-to-market activities	(21,376)	6,856				
Long-term incentive plan	322	145				
Unrealized loss/(gain) on natural gas derivatives/hedge ineffectiveness	(1,189)	1,225	(302)		15,265	(2,156)
Realized loss on cancelled gas derivatives						7,962
Adjusted EBITDA	$ 74,871	$ 52,520	$ 23,025	$ 16,198	$ 8,795	$ 14,738

(a) For the year ended December 31, 2004, the return on the preferred units subject to mandatory redemption totaled approximately $0.4 million. This amount is included in interest expense in the accompanying income statement and was also treated as non-cash additions to net income when calculating the net cash provided by operating activities. As this amount is already included in both interest expense and net cash provided by operating activities, it is not included in this line of the reconciliation.

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,

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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 natural gas, production volumes, estimates of proved reserves, capital expenditures, operating costs, sponsor support, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in Item 1A. Risk Factors and Forward-Looking Statements, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We are a limited liability company formed by Constellation Energy Group, Inc. (Constellation) on February 7, 2005 to acquire oil and natural gas properties (E&P properties) as well as related midstream assets. At December 31, 2008, our oil and natural gas reserves were located in the Black Warrior Basin of Alabama, in the Cherokee Basin of Kansas and Oklahoma, and in the Woodford Shale in Oklahoma. Our primary business objective is to generate stable cash flows allowing us to make quarterly cash distributions to our unitholders and over time to increase the amount of our future quarterly distributions. Our strategies for achieving this objective are to:

- organically grow our business by increasing reserves and production through what we believe to be low-risk development drilling that focuses on capital efficient production growth;
- reduce the volatility in our revenues resulting from changes in oil and natural gas commodity prices through efficient hedging programs;
- make accretive acquisitions of E&P properties characterized by a high percentage of proved developed reserves with long-lived, stable production and low-risk drilling opportunities, which may include associated midstream assets such as gathering systems, compression, dehydrating and treating facilities and other similar facilities; and
- realize value by opportunistically forming partnerships, participating in farm-out arrangements, joint operating agreements or other capital-efficient ventures to take advantage of our significant undeveloped acreage positions in the Cherokee Basin.

Our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing our current reserves and economically finding, developing and acquiring additional recoverable reserves. We may not be able to find, develop or acquire additional reserves to replace our current and future production at acceptable costs, which could materially adversely affect our business, financial condition and results of operations and our ability to pay quarterly cash distributions to our unitholders.

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

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

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We have expanded our operations by completing the following acquisitions that we have included in our results of operations and cash flows beginning with the period of acquisition:

In March 2008, we completed an acquisition of 83 non-operated producing wells located in the Woodford Shale in Oklahoma (the CoLa Assets or CoLa Acquisition).

In September 2007, we completed the acquisition of additional oil and natural gas properties in the Cherokee Basin of Oklahoma (the Newfield Assets or Newfield Acquisition).

In July 2007, we completed an acquisition of additional oil and natural gas properties located in the Cherokee Basin in Oklahoma (the Amvest Acquisition).

In April 2007, we completed an acquisition of oil and natural gas properties located in the Cherokee Basin in Kansas and Oklahoma (the EnergyQuest Assets or EnergyQuest Acquisition).

These acquisitions have provided us with the option to pursue organic growth by drilling on proved undeveloped and unproved locations primarily in Osage County, Oklahoma.

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

Significant Operational Factors

Realized Prices. Our average realized price for the twelve months ended December 31, 2008, including hedges, was $9.39 per Mcfe. This realized price includes the impact of $21.4 million of gains on mark-to-market derivatives. Excluding the impact of the mark-to-market gains, the average realized price for the twelve months ended December 31, 2008 was $8.13 per Mcfe. Further deducting the cost of sales associated with third party gathering, average realized prices were $8.97 per Mcfe including hedges and $7.71 per Mcfe excluding hedges.

Production. Our production during 2008 was approximately 17.4 Bcfe, or an average of 47,497 Mcfe per day.

Capital Expenditures and Drilling Results. During 2008, we incurred approximately $47.9 million in capital expenditures for development activities and approximately $48.1 million for acquisition activities. Our development activities were focused on completing the wells associated with our planned 2008 maintenance capital budget of $29.0 million. This maintenance capital spending is intended to maintain our production rates, reserves, and asset base. Through 2008, our drilling programs have successfully replaced production at a rate sufficient to offset the natural decline rate from our existing properties.

In the Black Warrior Basin, we drilled and completed 15 net wells with a 100% drilling success rate. The initial production rates from these wells are in line with expectations and continue to improve. We also drilled 100 net wells and performed 43 net recompletions in the Cherokee Basin with a 100% drilling success rate. We have steadily improved the cycle time for drilling and completing our wells in the Cherokee Basin. From the first half of 2008, we have now reduced the cycle time for our wells to flow to sales from approximately 90 days to approximately 75 days. As of February 1, 2009, we have also started drilling an additional 38 net wells and 1 net recompletion in the Cherokee Basin. Based on our fourth quarter 2008 and expected first quarter 2009 drilling and completion schedule, we do not expect to realize increased production rates until mid-2009.

In the Cherokee Basin, our drilling program currently includes 3 drilling rigs, 5 completion and well service rigs, and 5 dedicated construction and pipeline crews. We have continued to focus on horizontal drilling opportunities. In other coalbed methane basins, horizontal drilling technology has been successfully used to increase production and to increase economic returns. As the costs for horizontal drilling have declined and techniques have improved, we believe this type of drilling technology may be suitable in the Cherokee Basin. We expect that the costs for the horizontal wells will be marginally higher than our traditional vertical wells with higher production rates and reserves recoveries. In 2008, we have drilled and completed 11 net horizontal wells in Osage County, Oklahoma. Average initial production flow rates for these recently drilled horizontal wells have met or exceeded the flow rates of our recently drilled traditional vertical wells. We have completed 6 net horizontal wells in 2009, and expect to increase the use of horizontal drilling technologies in 2009. We will continue to evaluate the total costs, and the timing of the costs, associated with our 2009 drilling program, in light of our liquidity position, current oil and natural gas prices, and service costs in the Cherokee Basin.

Oil and Natural Gas Reserves. Our total year end 2008 proved reserves were 232.4 Bcfe which is 70.4 Bcfe lower than our year end 2007 proved reserves of 302.8 Bcfe. Our 2008 estimates of proved reserves decreased from 2007 primarily due to reserve revisions as a result of a lower year end price for natural gas. This decline was partially offset by our acquisition of reserves in the Woodford Shale and additions from our drilling programs. Our reserves are 99% natural gas and are sensitive to lower year end prices for natural gas and basis differentials in the Mid-Continent region. The year end natural gas price used to prepare our reserve report was $6.14 for NYMEX and $4.59 in the Cherokee Basin. Although we utilize swaps, options 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.

Lease Operating Expenses. Our lease operating expenses increased from 2007, reflecting the additional properties acquired in the EnergyQuest, Amvest, Newfield, and CoLa Acquisitions. Additionally, we experienced increased costs in the Cherokee Basin in connection with weather-related maintenance and repairs following a severe winter ice storm, a fire at our Dewey, Oklahoma field office, and additional costs of integrating and reorganizing our field offices surrounding Tulsa, Oklahoma. Our new technical office in Tulsa opened in May 2008 and is now the center of our operations in the Cherokee Basin. We have focused on cost control and have made progress on lowering our per unit lease operating expenses. For the year ended December 31, 2008, we have lowered our lease operating expenses to $2.09 per Mcfe from $2.24 per Mcfe at March 31, 2008.

Insured Loss. In January 2008, we experienced a fire at our field office in Dewey, Oklahoma. Both the facility and certain inventory and equipment were damaged. Substantially all of the damage to the building and equipment is expected to be covered by insurance, less a $5,000 deductible. However, certain expenses as a result of the business interruption resulting from the fire are not covered by insurance. These costs, such as temporary office space and other incremental expenses incurred as a result of the fire at the field office, will be expensed as they are incurred. We recorded a gain of $0.2 million as the insurance proceeds of $0.4 million exceeded the net book value of the building.

CoLa Acquisition and Impairment. On March 31, 2008, we acquired the interests in 83 non-operated producing wells located in the Woodford Shale in Coal and Hughes counties in Oklahoma for an aggregate purchase price of approximately $50.2 million, including purchase price adjustments through December 31, 2008. Approximately 90% of the wells are operated by affiliates of Devon Energy Company and Newfield Exploration Company, with the remaining wells operated by three additional companies. As of December 31, 2008, the wells have an average gross working interest of 11.4% and a net revenue interest per well of 9.2%.
At the time of the acquisition, proved developed producing reserves were estimated to be 12.7 Bcfe and the average annual decline rate for the reserves associated with these wells was estimated at 7 to 8 percent over 10 years. Our average daily production rate of 3.4 MMcfe per day since the acquisition is running 17 percent below the average daily production rate for 2008 of 4.1 MMcfe per day that was anticipated at the time of the acquisition. Decline rates during this period have been in excess of 30 percent annually, which has contributed to the difference in production rates. Because of this decline,

the future production decline projections in our year-end reserve report were updated using an exponential decline curve instead of a hyperbolic decline curve. Additionally, the market price for natural gas used to calculate our proved reserves under SEC rules has dramatically declined since the acquisition date. As a result of these factors, our proved reserves declined to 5.1 Bcfe at December 31, 2008, and we recorded a non-cash impairment charge of $25.7 million. This charge is reflected in our Statement of Operations as additional Depreciation, depletion, and amortization. See Notes 2 and 5 beginning on page 117 for additional details.

Hedging Activities. Our hedging program uses derivatives to reduce the impact of commodity price volatility on our anticipated cash flows. Our current intention is to hedge, subject to the terms of our reserve-based credit facilities, up to 80% of our forecasted production for up to a five year period. Our management, however, may modify the hedging percentages and strategies as it deems appropriate for market conditions, the cost associated with the derivatives and other business strategies.

We experience earnings volatility as a result of using the mark-to-market accounting method for certain of our commodity derivatives used to hedge our exposure to changes in natural gas prices or basis differentials. This accounting treatment can cause earnings volatility as the positions for future natural gas production are marked-to-market. These non-cash unrealized gains or losses are included in our current Statement of Operations until the derivatives are designated as cash flow hedges or are cash settled as the commodities are produced and sold. We do not enter into speculative trading positions and we only use derivatives to lock in the future sales price for a portion of our expected natural gas production. Increases in the market price of natural gas relative to the fixed future sales price for our hedges result in unrealized, non-cash mark-to-market losses on those derivatives and lower reported net income. Decreases in the market price of natural gas relative to the fixed future sales price for our hedges result in unrealized, non-cash mark-to-market gains on those derivatives and higher reported net income. Although these gains and losses are required to be reported immediately in earnings as market prices change, the fair value of the related future physical natural gas sale is not marked-to-market and therefore is not reflected as Oil and Gas Sales or as an Accounts Receivable in our financial statements. This mismatch impacts our reported Result of Operations and our reported working capital position until the commodity derivatives are cash settled and the natural gas is produced and sold. Upon cash settlement of the derivatives, the sale of the physical commodity at then-current market prices offsets the previously reported mark-to-market gains or losses such that the cumulative net cash realized results in a net sale of the physical natural gas production at the fixed future sales price for our hedge. When our derivative positions are cash settled as the related commodities are produced and sold, the realized gains and losses of those derivative positions are included in our Statement of Operations as Oil and Gas Sales. A further detail of our commodity derivative positions and their accounting treatment is outlined starting on page 68.

Debt. We entered into a new reserve-based credit facility and amended our existing credit facility during the first quarter 2008. The two agreements contain similar commercial terms with the same lenders participating in the same applicable percentages. A cross-default feature provides that an event of default under one agreement constitutes an event of default under the other. Each credit agreement is secured by distinct mortgages of properties as well as guarantees by certain of our operating subsidiaries. The credit facilities will mature in October 2010 and will have to be renewed or replaced before that time. As of December 31, 2008, the combined borrowing base under the reserve-based credit facilities was $265.0 million. Outstanding borrowings under the credit facilities totaled $212.5 million as of December 31, 2008. Since December 31, 2008, the Company has borrowed an additional $7.5 million. As of February 20, 2009, the Company had $220.0 million in debt outstanding under its reserve-based credit facilities. The Company believes it was in compliance with all of its debt covenants at December 31, 2008, and remains in compliance as of February 20, 2009.

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Significant Market Factors

Market Events Impacting our Sponsor. In September 2008, Constellation announced that it had entered into a definitive merger agreement with MidAmerican Energy Holdings Company (MidAmerican) in which MidAmerican would purchase all of the outstanding shares of Constellation. At that time, Constellation publicly announced that it planned to proceed with its previously announced sale of its upstream gas assets. Constellation also acknowledged that it had not yet made any statements regarding its plans for its interests in us. At that time, Constellation reaffirmed the commitment to providing us services under the management services agreement. In December 2008, the merger agreement with MidAmerican was terminated and an alternative investment transaction with EDF Group was announced which is expected to close in the third quarter of 2009 subject to receipt of required regulatory approvals and other standard closing conditions. Constellation owns all of our outstanding Class A units, approximately 5.9 million Class B Common Units, all of our Class D interests, and all of the Management Incentive Interests.

Unit Price Performance. During June 2008, our units were trading in a range near our initial public offering price of $21.00. Since that time, our unit price has substantially decreased to $2.78 as of December 31, 2008.

Our unit price performance was impacted by market events including but not limited to: continued turmoil in the global financial markets and the continued crisis in global credit markets; bankruptcy filings and other credit market events that specifically impacted a number of peers in the E&P MLP sector; a dramatic decrease in the market prices of oil and natural gas; announcements of capital spending reductions and other business issues at domestic E&P companies; and an unfavorable market view of MLPs specifically E&P MLPs.

Our unit price performance was also impacted by company-specific events including but not limited to: the termination of the Torch Energy Royalty Trust and the related arbitration proceeding; leadership and management changes in the positions of the Chairman of the Board of Managers, chief executive officer, and chief financial officer; integration issues, delays in our drilling program, and other weather-related challenges in our Cherokee Basin operations which negatively impacted our expected full year 2008 performance and resulted in downgrades of our units from market analysts; market concerns about our current distribution yield and the sustainability of our distribution rate; and Constellation announcements regarding registration of its common units for sale, the proposed sale of its upstream gas assets, its terminated merger agreement with MidAmerican, and other questions concerning its commitment to sponsor us.

Strategic Advisor. In September 2008, we retained a financial advisor to assist in a review of strategic alternatives to enhance unitholder value. Tudor, Pickering, Holt & Co. Securities, Inc. has been engaged to provide independent advice to our management team and Board of Managers. At this time, our Board of Managers has determined to initially focus on internal opportunities and to run our business by transitioning our executive management team from being provided under the management services agreement to employees of CEP. We do not intend to disclose developments with respect to this review unless and until the Board of Managers has approved a course of action.

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Results of Operations

The following table sets forth the selected financial and operating data for the periods indicated:

	For the year ended December 31, 2008	For the year ended December 31, 2007	2008 Vs 2007 Variance $	2008 Vs 2007 Variance %	For the year ended December 31, 2006	2007 Vs 2006 Variance $	2007 Vs 2006 Variance %
Revenues:							
Oil and gas sales	$ 141,863	$ 82,725	$ 59,138	71.5%	$ 36,917	$ 45,808	124.1%
Gain (Loss) from mark-to- market activities	21,376	(6,856)	28,232	(411.8)%		(6,856)	N/A%
Total revenues	163,239	75,869	87,370	115.2%	36,917	38,952	105.5%
Operating expenses:							
Lease operating expenses	36,257	17,141	19,116	111.5%	7,234	9,907	137.0%
Cost of sales	7,261	1,788	5,473	306.1%		1,788	N/A%
Production taxes	8,398	3,646	4,752	130.3%	1,783	1,863	104.5%
General and administrative expenses	14,412	9,109	5,303	58.2%	4,573	4,536	99.2%
(Gain) loss on sale of asset	(301)	86	(387)	(450.0)%		86	N/A%
Depreciation, depletion and amortization	77,919	23,190	54,729	236.0%	7,444	15,746	211.5%
Accretion expenses	411	312	99	31.7%	141	171	121.3%
Total operating expenses	144,357	55,272	89,085	161.2%	21,175	34,097	161.0%
Other expenses (income):							
Interest expense	12,167	6,930	5,237	75.6%	221	6,709	3,035.7%
Interest income	(350)	(465)	115	(24.7)%	(468)	3	(0.6)%
Other (income) expense	(203)	(109)	(94)	(86.2)%		(109)	N/A%
Total other expenses (income)	11,614	6,356	5,258	82.7%	(247)	6,603	(2,673.3)%
Total expenses	155,971	61,628	94,343	153.1%	20,928	40,700	194.5%
Net income	$ 7,268	$ 14,241	$ (6,973)	(49.0)%	$ 15,989	$ (1,748)	(10.9)%
Net production:							
Total production (MMcfe)	17,384	10,393	6,991	67.3%	4,641	5,752	123.9%
Average daily production (Mcfe/d)	47,497	28,474	19,023	66.8%	12,715	15,759	123.9%
Average sales prices:							
Price per Mcfe including hedges[(a)]	$ 9.39	$ 7.30	$ 2.09	28.6%	$ 7.95	$ (0.65)	(8.2)%
Price per Mcfe excluding hedges	$ 8.13	$ 6.51	$ 1.62	24.9%	$ 7.43	$ (0.92)	(12.4)%
Average unit costs per Mcfe:							
Field operating expenses [(b)]	$ 2.57	$ 2.00	$ 0.57	28.4%	$ 1.94	$ 0.06	2.9%
Lease operating expenses	$ 2.09	$ 1.65	$ 0.44	26.5%	$ 1.56	$ 0.09	5.8%
Production taxes	$ 0.48	$ 0.35	$ 0.13	37.7%	$ 0.38	$ (0.03)	(8.7)%
General and administrative expenses	$ 0.83	$ 0.88	$ (0.05)	(5.4)%	$ 0.99	$ (0.11)	(11.1)%
Depreciation, depletion and amortization[(c)]	$ 4.48	$ 2.23	$ 2.25	100.9%	$ 1.60	$ 0.63	39.1%

(a) Price per Mcfe including hedges includes realized and unrealized mark-to-market losses on derivative transactions that did not qualify for hedge accounting treatment.

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

(c) Depreciation, depletion and amortization includes non-cash impairments of oil and natural gas assets. Excluding impairments, the 2008 cost per Mcfe was $3.01.

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

Oil and natural gas sales. Oil and natural gas sales increased $59.1 million, or 71.5%, to $141.8 million for the year ended December 31, 2008 as compared to $82.7 million for the same period in 2007. Of this increase, $45.4 million was attributable to increased production volumes and $28.2 million was attributable to higher market prices for oil and natural gas, offset by a $14.6 million decrease attributable to our hedge program. Production for the year ended December 31, 2008 was 17.4 Bcfe, which was 7.0 Bcfe higher than the same period in 2007, as a result of the acquisition of our properties in the Cherokee Basin and in the Woodford Shale and our maintenance drilling program substantially offsetting the natural decline rate of production associated with our existing wells. Our production in the Black Warrior Basin has remained essentially level. We hedged approximately 89% of our actual production during 2008 and approximately 90% of our actual production during 2007.

As discussed below, the gain from our unrealized non-cash mark-to-market activities increased $28.2 million for the year ended December 31, 2008, as compared to the same period in 2007. Our realized prices before our hedging program increased from 2007 to 2008 primarily due to higher market prices for oil and natural gas. This was offset by our hedging program and the mark-to-market gains discussed below.

Hedging and mark-to-market activities. We have certain swaps, put options, and basis swaps that are accounted for as mark-to-market derivatives. For the year ended December 31, 2008, the unrealized non-cash mark-to-market gain was approximately $21.4 million as compared to an unrealized non-cash $6.9 million loss for the same period in 2007. This 2008 non-cash gain represents approximately $20.8 million from the impact of lower expected future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities, $0.4 million loss for non-performance risk related to our counterparties, and approximately $1.0 million from the termination of hedge accounting on swaps for natural gas production between 2008 and 2013 for volumes associated with our CoLa acquisition as we expect future actual production to be lower than anticipated due to a higher than anticipated production decline rate for the reserves.

We have entered into cash flow hedges in an effort to reduce our exposure to short-term fluctuations in natural gas prices. For the year ended December 31, 2008, we recognized a gain of approximately $1.2 million related to hedge ineffectiveness primarily related to our hedges of production in the Cherokee Basin. For the year ended December 31, 2007, we recognized a loss of approximately $1.2 million related to hedge ineffectiveness.

Cash hedge settlements paid for our commodity derivatives were approximately $0.7 million for the year ended December 31, 2008. Cash hedge settlements received for our commodity derivatives were $16.3 million for the year ended December 31, 2007. This difference is primarily due to higher market prices for natural gas during mid-2008. In 2008, we also liquidated our swaption position for cash proceeds of approximately $2.1 million. The original premium paid for the swaption was approximately $1.9 million in 2007.

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

For the year ended December 31, 2008, lease operating expenses increased $19.1 million, or 111.5%, to $36.2 million, compared to expenses of $19.1 million for the same period in 2007. Of the $19.1 million increase in lease operating expenses, $17.0 million is related to our Cherokee Basin properties, $1.8 million is related to our Woodford Shale acquisition, and $0.3 million is related to the Black Warrior Basin. The majority of the increase was the result of the full year costs of operating the properties acquired in the EnergyQuest, Amvest, and Newfield Acquisitions. By category, our lease operating expenses were higher in 2008 as compared to 2007, because of an increase of $7.0 million in compression, treating, salt water disposal and transportation charges, $3.1 million in well servicing costs, $2.6 million in labor and benefits, $1.5 million in repairs and maintenance, $1.5 million in insurance expenses, $1.3 million in power and fuel charges, $0.9 million in non-operated lease operating expenses, $0.7 million in vehicle expenses, $0.6 million in field reorganization expenses, $0.2 million in ad valorem taxes, and $0.2 million in incremental expenses associated with the Dewey office fire offset by $0.6 million in lower equipment rentals.

For the year ended December 31, 2008, per unit lease operating expenses were $2.09 per Mcfe compared to $1.65 per Mcfe for the same period in 2007. Our per unit operating costs in 2008 in the Black Warrior Basin have remained essentially level with our operating costs in 2007. Certain weather-related and specific field office events described below, which are not expected to be ongoing, contributed to the per unit increase in operating expenses experienced in the Cherokee Basin compared to 2007. During 2008, our lease operating expenses in the Cherokee Basin were impacted by $0.5 million in repair costs to restore production after a significant winter ice storm in Oklahoma, $0.8 million of field reorganization expenses in Tulsa, $0.3 million in costs associated with the final Newfield settlement under the transition services agreement, and $0.7 million in incremental expenses associated with the Dewey office fire, surface damages, shut-in payments, and environmental costs. We have worked to lower our per unit operating costs during 2008. Our per unit lease operating expenses for the year ended December 31, 2008 were $2.09 per Mcfe, which has decreased from $2.24 per Mcfe for the three months ended March 31, 2008. Although this is higher than our $1.65 per Mcfe rate for the year ended December 31, 2007, we expect our lease operating expenses to remain level per Mcfe for the twelve months ended December 31, 2009.

For the year ended December 31, 2008, production taxes increased $4.8 million, or 130.3%, to $8.4 million, compared to expenses of $3.6 million for the same period in 2007. This increase was primarily the result of the additional taxes resulting from oil and natural gas production in Oklahoma and Kansas as a result of the EnergyQuest, Amvest, Newfield, and CoLa Acquisitions and higher market prices for oil and natural gas in mid-2008.

Cost of sales. For the year ended December 31, 2008, cost of sales increased by $5.5 million, or 306.1%, to $7.3 million, compared to $1.8 million for the same period in 2007. This represents the cost of purchased natural gas in the Cherokee Basin and was impacted by higher natural gas prices and a full year of operations for our Cherokee Basin properties.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, costs billed by CEPM under our management services agreement and other costs not directly associated with field operations.

General and administrative expenses increased $5.3 million, or 58.2%, to $14.4 million for the year ended December 31, 2008, as compared to $9.1 million for the same period in 2007. This increase was primarily due to our acquisitions in the Cherokee Basin increasing our administrative overhead burdens. Our general and administrative expenses were higher in 2008 as compared to 2007 because of $1.3 million in administrative costs in Tulsa, $1.2 million in legal fees primarily associated with the Torch arbitration, $0.9 million in CEPM charges for labor, $0.9 million in professional services costs primarily associated with providing outsourced accounting services for our properties in the Cherokee Basin, $0.4 million in audit and tax fees, $0.3 million associated with the retention of a strategic advisor, $0.2 million in non-cash expenses associated with restricted unit grants under our long-term incentive program, and $0.1 million in credit support fees to Constellation. For the year ended December 31, 2008 and 2007, CEPM allocated $2.9 million and $1.4 million, respectively, in expenses to us for labor and other charges through the management services agreement.

Our per unit costs were $0.83 per Mcfe for the year ended December 31, 2008 compared to $0.88 per Mcfe for the same period in 2007. This decrease is attributable to increased production volumes as a result of our acquisitions in the Cherokee Basin and the Woodford Shale, as well as the economies of scale associated with spreading fixed administrative expenses over a larger base of properties.

Gain/loss on sale of asset. Our gain/loss on the sale of assets increased $0.4 million, or 450.0%, to a gain of $0.3 million for the year ended December 31, 2008, as compared to a loss of $0.1 million for the same period in 2007. In 2008, a fire damaged our field office located in Dewey, Oklahoma. A gain of $0.2 million was recorded for the involuntary conversion as the insurance proceeds of $0.4 million exceeded the $0.2 million book value of the building. In February 2007, we sold a surplus compressor for $0.2 million and recorded a $0.1 million loss on the sale.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production. Assuming everything else remains unchanged, as natural gas production changes, depletion would change in the same direction.

Our depreciation, depletion and amortization expense for the year ended December 31, 2008 was $77.9 million, or $4.48 per Mcfe, compared to $23.2 million, or $2.23 per Mcfe, for the same period in 2007. Approximately one half of this increase was driven by an impairment charge of $25.7 million related to our Woodford Shale properties. This impairment was primarily caused by reserve revisions caused by the impact of lower production volumes than originally estimated, a higher initial production decline rate, and lower future expected prices for natural gas. The remainder of this increase in 2008 depreciation, depletion, and amortization reflects the increased basis in our assets resulting from the cost of our asset acquisitions in the Cherokee Basin, additional capital expenditures for our development drilling programs, and a 7.0 Bcfe increase in production volumes during 2008 as compared to 2007. We calculate depletion using units-of-production under the successful efforts method of accounting except for our other assets which are depreciated using the straight line basis.

Interest expense. Interest expense for the year ended December 31, 2008 increased $5.3 million to $12.2 million as compared to approximately $6.9 million in interest expense for same period in 2007. This increase was due to increased borrowings under our reserve-based credit facilities to finance the acquisition of our Woodford Shale properties, investment capital expenditures and the accelerated amortization of $0.1 million in debt issue costs as a result of amending our credit facility. At December 31, 2008, we had an outstanding balance under our credit facilities of $212.5 million as compared to $153.0 million at December 31, 2007. The average interest rate on our outstanding debt was 5.45% in 2008.

Interest income. Interest income for the year ended December 31, 2008 decreased $0.1 million to $0.4 million as compared to approximately $0.5 million in interest expense for same period in 2007. During 2008 and 2007, we earned interest income by utilizing overnight investments on our excess cash balances. Throughout 2008 interest rates on overnight investment balances significantly declined as a result of the credit crisis and global recession. In March 2008, we received $0.1 million in interest on payment balances from receivables related to the sales of natural gas included in the Torch NPI escrow account. Effective with the termination of the Trust, the escrow account arrangement has also terminated and all payments for natural gas sales are directly received by us.

Accumulated other comprehensive income. Accumulated other comprehensive income, shown on our consolidated balance sheets, reflects the changes in the fair market value of our open hedge positions. At December 31, 2008, the balance was an unrealized gain of $50.1 million compared to an unrealized gain of $4.2 million at December 31, 2007. This increase primarily reflects the decrease in the market prices for natural gas.

The change in Accumulated other comprehensive income (loss) is shown in our consolidated statements of operations and comprehensive income (loss) as an unrealized gain of $45.9 million for the year ended December 31, 2008, and as an unrealized loss of $8.9 million for the same period in 2007. This change is primarily due to the impact of the decrease in expected future market prices for natural gas on our outstanding commodity derivatives accounted for as cash flow hedges. This impact was offset by the impact of decrease in expected future LIBOR interest rates on our outstanding interest rate swaps accounted for as cash flow hedges and a $0.5 million adjustment for non-performance risk related to our counterparties. Notwithstanding these unrealized gains on our commodity derivatives for natural gas, as these positions cash settle in the future, we expect to realize an offsetting loss upon the physical sale of natural gas production for which these hedges have fixed the future sales price.

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Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Oil and natural gas sales. Oil and natural gas sales increased $45.8 million, or 124.1%, to $82.7 million for the year ended December 31, 2007. Of this increase, $45.4 million was attributable to increased production volumes and $14.8 million was attributable to our hedge program, offset by a $14.4 million impact of lower market prices for oil and natural gas. Production for the year ended December 31, 2007 was 10.4 Bcfe, or 123.9% higher than the year ended December 31, 2006 as a result of our drilling program and operational improvements, along with the acquisition of our properties in the Cherokee Basin. The acquisition of our properties in the Cherokee Basin contributed 5.3 Bcfe of the increase. We hedged approximately 90% of our actual production through December 2007. As discussed below, the change in our mark-to-market activities was a decrease of $6.8 million for the year ended December 31, 2007, as compared to the year ended December 31, 2006. Our realized prices before hedging declined from 2006 to 2007 because of lower natural gas prices and the impact of our mark-to-market activities described below.

Hedging and mark-to-market activities. We did not have mark-to-market derivatives for the year ended December 31, 2006. However, in conjunction with the EnergyQuest, Amvest, and Newfield Acquisitions, we entered into derivative transactions to hedge a portion of the future expected production associated with these acquisitions before the acquisitions closed. These derivatives were accounted for as mark-to-market derivatives and were recorded at fair value in our financial statements until June 18, 2007 for EnergyQuest and August 20, 2007 for Amvest, at which time the swaps were designated as cash flow hedges and began receiving cash flow hedge accounting treatment. The Newfield swaps were accounted for as mark-to-market derivatives. For the year ended December 31, 2007, the unrealized mark-to-market loss was $6.8 million. The put options related to the production from the EnergyQuest Acquisition and the Newfield swaps were accounted for using the mark-to-market method of accounting.

We entered into cash flow hedges beginning in October 2006 in an effort to reduce our exposure to short-term fluctuations in natural gas prices. For the year ended December 31, 2007, we recognized a loss of approximately $1.2 million related to hedge ineffectiveness. For the year ended December 31, 2006, we recognized a gain of approximately $0.3 million related to hedge ineffectiveness. Hedge settlements were a gain of approximately $16.3 million for the year ended December 31, 2007.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, as well as production and ad valorem taxes. Production taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by county and are based on the value of our wells, equipment and reserves. We assess our field operating expenses by monitoring the expenses in relation to the volume of production and the number of producing wells.

For the year ended December 31, 2007, field operating expenses increased $11.8 million, or 130.5%, to $20.8 million, compared to expenses of $9.0 million for the same period in 2006. This increase was the result of costs of operating the properties acquired in the Cherokee Basin. In the Black Warrior Basin, per unit costs decreased from $1.94 per Mcfe in 2006 to $1.75 per Mcfe in 2007. Our operating expenses in the Cherokee Basin were impacted by the flooding in late summer 2007 and the severe ice storm in December 2007. We had $0.1 million in costs associated with closing the Amvest corporate office in Charlottesville, Virginia. Our per unit costs increased from $1.94 per Mcfe in 2006 to $2.00 per Mcfe in 2007 due to increased maintenance and workover costs and the addition of our properties in the Cherokee Basin.

Cost of sales. Cost of sales for the year ended December 31, 2007 was $1.8 million, which represents the cost of third-party purchased natural gas and gas transportation in the Cherokee Basin. Associated revenues for third-party activities are included in oil and gas sales.

General and administrative expenses. General and administrative expenses included the costs of our employees, related benefits, field office expenses, professional fees, costs billed by CEPM under our management services agreement and other costs not directly associated with field operations. We monitor general and administrative expenses in relation to our production volumes and the number of producing wells.

General and administrative expenses increased $4.5 million, or 99%, to $9.1 million for the year ended December 31, 2007, as compared to the same period in 2006. This increase was primarily due to the increased expenses related to being a public company, expenses associated with the transition services agreements with EnergyQuest, Amvest, and Newfield, expenses related to acquisition and integration costs associated with our acquisitions, $0.6 million in expenses related to the Constellation credit support fees, $0.1 million for Internal Audit services and costs related to Sarbanes-Oxley compliance, $0.3 million for lease expirations, acquisition efforts, and exploration expenses, $0.1 million for non-cash expenses associated with our Long-Term Incentive Plan, $0.3 million associated with the Torch NPI arbitration, and expenses related to the management services agreement, under which CEPM bills us for services and costs incurred on our behalf. Our-per unit costs for general and administrative expenses declined from $0.99 per Mcfe in 2006 to $0.88 per Mcfe in 2007 because of higher production volumes and economies of scale.

Loss on sale of asset. In 2007, we sold a surplus compressor for approximately $0.2 million and recorded a loss on the sale of $0.1 million.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production. Assuming everything else remains unchanged, as natural gas production changes, depletion would change in the same direction.

Our depreciation, depletion and amortization expense for the year ended December 31, 2007 was $23.2 million, or $2.23 per Mcfe, compared to $7.4 million, or $1.60 per Mcfe, for the year same period in 2006. This increase reflects our increased production volumes, asset acquisitions, and the increased basis in our assets resulting from additional capital expenditures during the year ended December 31, 2007. We calculate depletion using units-of-production under the successful efforts method of accounting except for our other assets which are depreciated using the straight line basis.

Interest expense. Interest expense for the year ended December 31, 2007 increased $6.7 million as compared to approximately $0.2 million in interest expense for the same period in 2006. This increase was due to the timing of our borrowings under our reserve-based credit facility, which we entered into on October 31, 2006.

At December 31, 2007, we had an outstanding balance under the credit facility of $153.0 million. Interest expense was partially offset by $0.1 million of gain realized on an interest rate swap that was terminated in June 2007 and capitalized interest of $0.1 million. The average interest rate on our outstanding debt in 2007 was 7.27%.

Interest income. Interest income was $0.5 million for the years ended December 31, 2007 and 2006. During the year ended December 31, 2007, we earned interest income by utilizing overnight investments on our excess cash balances. In 2006, our interest income was earned on our cash pool arrangement with CCG. As of November 2006, we ceased participation in the cash pool arrangement.

Accumulated other comprehensive income. Accumulated other comprehensive income, shown on our consolidated balance sheets, reflects the changes in the fair market value of our open hedge positions. At December 31, 2007, the balance was an unrealized gain of $4.2 million compared to an unrealized gain of $13.1 million at December 31, 2006. This decrease reflects an increase in the market prices for natural gas in conjunction with an increase of hedged production as a result of our acquisitions.

The change in Accumulated other comprehensive income is shown in our consolidated statements of operations and comprehensive income as a loss of $8.9 million for the year ended December 31, 2007, and as a gain of $13.1 million for the year ended December 31, 2006.

Liquidity and Capital Resources

During 2008, we utilized proceeds from borrowings under our credit facilities and cash flow from operations as our primary sources of capital. Our primary use of capital during 2008 has been for the development of existing oil and natural gas properties and the acquisition of additional natural gas properties in the Woodford Shale. As we pursue our business plans, we will be monitoring the capital resources available to us to meet our future financial obligations and planned capital expenditures. 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. Based upon our current business plans, we expect to continue to generate cash flow sufficient to support our projected maintenance capital expenditures and operations of our business. Our results will not be fully impacted by significant increases or decreases in natural gas prices because of our hedging program, which is further discussed on page 68.

Our reserve-based credit facilities may also be used to help finance future expansion capital expenditures, such as drilling and recompletions beyond that required to maintain production, as well as additional acquisitions. As of December 31, 2008, our total borrowing base under our reserve-based credit facilities was $265.0 million. At December 31, 2008, we had $212.5 million of debt outstanding under the reserve-based credit facilities and $52.5 million in unused borrowing capacity. Of this $52.5 million in unused borrowing capacity at December 31, 2008, $26.0 million was available for borrowings that would allow us to remain in compliance with our debt covenants at our fourth quarter 2008 distribution level. Our credit facilities mature in October 2010. In the first quarter of 2008, we filed a shelf registration statement with the SEC to register up to $1.0 billion of debt or equity securities to fund future expansion capital expenditures. This registration statement is now effective. There is no guarantee that securities can or will be issued under the registration statement. Based on current financial market conditions and market prices for oil and natural gas, we expect capital markets to remain constrained which will make issuing additional debt or equity securities difficult or not possible at all. Our credit facilities allow us the ability to issue up to $300 million of unsecured debt, which would have the effect of reducing the total borrowing base under our reserve-based credit facilities by 30 cents for every dollar of unsecured debt issued.

For 2009, we continue to expect to fund our maintenance capital expenditures and other working capital needs with cash flow from operations supplemented by borrowings under our credit facilities. Our expectation is that we will manage our business to operate within the cash flows that are generated. We expect that our recently announced quarterly distribution rate of $0.13 per common unit and a reduction in our total planned capital expenditures will provide additional liquidity to fund our operations. We estimate that we will have sufficient cash flow from operations after funding our maintenance capital expenditures to enable us to make quarterly cash distributions payable to unitholders through December 31, 2009, as set by our Board of Managers. Our future quarterly distribution rate to unitholders has not been announced, but we anticipate that any future distribution rates will be set at a sustainable level. Our quarterly distribution rate must be approved by our Board of Managers.

CEPM currently holds management incentive interests in us that represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in our limited liability company agreement) has been achieved and certain other tests have been met. Based on our distribution level, beginning in the fourth quarter 2007, we commenced a management incentive interest vesting period. A cash reserve of $0.7 million was established to fund future distributions on the management incentive interests. In February 2009, the Company reduced its distribution rate to $0.13 per unit for the fourth quarter of 2008. This decrease in the distribution rate terminated the initial management incentive interest vesting period. After the February 13, 2009 distribution was paid, the reserve was reduced to zero.

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Reserve-Based Credit Facilities

On March 28, 2008, we entered into a new $500.0 million secured credit facility with The Royal Bank of Scotland as administrative agent and a syndicate of lenders. The amount available for borrowing at any one time under the Credit Facility is limited to the borrowing base for our properties other than in the State of Alabama, which was initially set at $150.0 million. In July 2008, we expanded our borrowing base under this facility to $175.0 million, which had the effect of increasing remaining capacity under the Credit Facility to $40.0 million. As of December 31, 2008, we have borrowed $131.5 million and have a remaining capacity of $43.5 million under the Credit Facility. Of this $43.5 million in unused borrowing capacity, $26.0 million was available for borrowings that would allow us to remain in compliance with our debt covenants at our current distribution level. On March 28, 2008, we also amended and restated our existing $200.0 million credit facility by entering into an amended and restated credit agreement with The Royal Bank of Scotland as administrative agent and a syndicate of lenders. The amount available for borrowing at any one time under the Amended and Restated Credit Facility is limited to the borrowing base for our properties in the State of Alabama, which was initially set at $90.0 million. As of December 31, 2008, we have borrowed $81.0 million and have a remaining capacity of $9.0 million under the Amended and Restated Credit Facility. Of this $9.0 million in unused borrowing capacity, we cannot borrow any additional amounts on this facility and remain in compliance with our debt covenant at our current distribution level. Both of our credit facilities will mature on October 31, 2010 and the amounts due under these facilities become a current liability on October 31, 2009. We will need to renew or replace these credit facilities prior to their maturity date. There is no guarantee that we will be able to renew these facilities. Even if we do renew or replace these facilities, it may not be possible to do so with similar borrowing costs, terms, or covenants or at the same borrowing base.

As of February 20, 2009, we had $220.0 million in debt outstanding under these two credit facilities. The amount available for borrowing at any one time is limited to the borrowing base under each facility. The 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, together with, among other things, the oil and natural gas prices at such time. Any increase in the borrowing base will have to be approved by all of the lenders in the syndicate and any decrease in the borrowing base will have to be approved by lenders holding at least 66 2/3% of the commitments. Our borrowing base was reaffirmed in November 2008 and our next borrowing base redetermination should be in mid-2009. At that time, it is possible that our borrowing base could decrease because of lower oil and natural gas prices or other factors.

Our reserve-based credit facilities contain similar commercial terms with the same lenders participating in the same applicable percentages. The current lenders and their percentage commitments in the two facilities are: The Royal Bank of Scotland (23.32%), BNP Paribas (22.55%), Wachovia Bank, N.A. (14.55%), Bank of Nova Scotia (17.00%), Calyon New York Branch (15.05%), and Societe Generale (7.53%). A cross-default feature provides that an event of default under one agreement constitutes an event of default under the other. Our obligations under our credit facilities are secured by mortgages on our natural gas properties, as well as a pledge of all ownership interests in our subsidiaries. We are required to maintain the mortgages on properties representing at least 85% of our proved producing and proved non-producing reserves. Additionally, the obligations under the credit facilities are guaranteed by all of our operating subsidiaries and any future material subsidiaries.

Borrowings under our credit facilities are available to us for acquisition, exploration, operation and maintenance of oil and natural gas properties, payment of expenses incurred in connection with the credit facility, working capital and general limited liability company purposes. A sub-limit of $20.0 million of the facility applies for letters of credit.

At our election, interest will be determined by reference to:

- LIBOR plus an applicable margin between 1.25% and 2.00% per annum based on utilization; or
- a domestic bank rate plus an applicable margin between 0.25% and 1.00% per annum based on utilization.

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Interest will generally be payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

Our credit facilities contain various covenants that limit our ability to:

- incur indebtedness;
- grant certain liens;
- make certain loans, acquisitions, capital expenditures and investments;
- make distributions other than from available cash;
- merge or consolidate; or
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

Our credit facilities also contain covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- debt to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus 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, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on natural gas derivatives and realized (gain) loss on cancelled natural gas derivatives, and other similar charges) of not greater than 3.5 to 1.0; and
- Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and
- 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, of not less than 1.0 to 1.0, all calculated pursuant to the requirements under Statement of Financial Accounting Standards (SFAS) 133 and SFAS 143 (including the current liabilities in respect of the termination of natural gas and interest rate swaps).

A failure to maintain the foregoing ratios could result in an acceleration of any indebtedness in excess of $1.0 million and would constitute an event of default that would prohibit us from making distributions.

We have the ability to borrow under our credit facilities to pay distributions to unitholders as long as there has not been a default or event of default and if the amount of borrowings outstanding under our credit facilities is less than 90% of the borrowing base.

If an event of default exists under our credit facilities, the lenders will be able to accelerate the maturity of the credit facility and exercise other customary rights and remedies. Each of the following is an event of default:

- failure to pay any principal when due or any interest, fees or other amount within 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; and

failure to perform or otherwise comply with the covenants in the credit facility or other loan documents, subject, in certain instances, to certain grace periods, which include covenants that:

Constellation and its affiliates maintain the right to elect our Class A Managers; and

we obtain the approval of the administrative agent (such approval not to be unreasonably withheld or delayed) of any management services plan upon the termination of the management services agreement with CEPM;

- any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or our subsidiaries;
- 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;
- 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; and
- a change of control, generally defined as the first date on which both of the following two conditions occur: (i) a decrease by CEPH and CEPM of their combined ownership of our outstanding membership interests to less than 20%, and (ii) the ownership by any person (other than a wholly-owned subsidiary of Constellation) of more than 35% of our outstanding membership interests.

The reserve-based credit facilities contain a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, amount 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 the Company and its subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the facilities and we would be in default under the facilities, which could cause all of our existing indebtedness to become immediately due and payable.

At December 31, 2008, we believe that we were in compliance with the debt covenants contained in our credit facilities. We monitor compliance on an ongoing basis. As of December 31, 2008, our actual debt to Adjusted EBITDA ratio was 2.8 to 1.0 as compared with a required ratio of not greater than 3.5 to 1.0, our actual ratio of current assets to current liabilities was 3.5 to 1.0 as compared with a required ratio of not less than 1.0 to 1.0, and our actual Adjusted EBITDA to cash interest expense ratio was 7.2 to 1.0 as compared with a required ratio of not less than 2.5 to 1.0.

If CEP is unable to remain in compliance with the debt covenants associated with its reserve-based credit facilities or maintain the required ratios discussed above, CEP could request waivers from the lenders in its bank group. Although the lenders may not provide a waiver, CEP may take additional steps in the event of not meeting the required ratios or in the event of a reduction in the combined borrowing base below its current level of $265.0 million at one of the future redeterminations by the lenders. If it becomes necessary to pay debt down beyond operating cash flows, CEP could reduce capital expenditures, further reduce or eliminate quarterly distributions to unitholders, sell oil and natural gas properties, liquidate in the money derivative positions, further reduce operating and administrative costs, or take additional steps to increase liquidity. To the extent that CEP does not enter into an agreement to refinance or extend the due date on the reserve-based credit facilities, the outstanding debt balance at October 31, 2009, will become a current liability.

We enter into hedging arrangements to reduce the impact of changes in the LIBOR interest rate on our interest payments for our reserve-based credit facilities. These positions are outlined on page 80.

Cash Flow from Operations

Our net cash flow provided by operating activities for the year ended December 31, 2008 was $75.6 million, compared to net cash flow provided by operating activities of $42.5 million for the same period in 2007. This increase in operating cash flow was primarily attributable to higher sales of oil and natural gas as a result of our acquisitions in the Cherokee Basin and the Woodford Shale and the impact of higher market prices for natural gas on our unhedged production volumes. For 2008, our operating cash flows were reduced by $2.2 million related to cash hedge settlements for our natural gas commodity and interest rate derivatives. This was positively impacted when we liquidated all of our swaption positions for 2009 for cash proceeds of approximately $2.1 million. The original premium paid for the swaption was approximately $1.9 million in 2007. Our change in working capital from 2007 to 2008 was impacted by lower accounts receivable of $9.1 million and higher royalties payable of $2.2 million that were partially offset by lower accrued liabilities of $2.2 million and lower affiliate payables of $1.8 million. Our receivables balance decreased due to increased collections and lower current period prices for our current estimated natural gas sales prices in the Cherokee Basin. The royalties payable, which represents the amount of monies owed to the royalty owners in our properties for the monthly oil and natural gas sales, increased due to higher market prices for oil and natural gas. The decrease in affiliate payables of $1.8 million primarily resulted from the timing of the payment for 2007 expenses accrued under the management services agreement with CEPM. We began receiving cash flows from our Woodford Shale properties in the second quarter of 2008.

Our net cash flow provided by operating activities for the year ended December 31, 2007 was $42.5 million, compared to net cash flow provided by operating activities of $14.1 million for the same period in 2006. This increase in operating cash flow was primarily attributable to the increase in sales of oil and natural gas as a result of our acquisitions in the Cherokee Basin.

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 programs or completing acquisitions, as well as the market prices of oil and natural gas and our hedging program.

We enter into hedging arrangements to reduce the impact of natural gas price volatility on our operations. By removing the price volatility from a significant portion of our natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to recoup higher severance taxes, which are usually based on market prices for 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 recoup these higher costs. Increases in the market prices for natural gas will also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to our derivative contracts is a lender in our reserve-based credit facilities. We do not post collateral under any of these agreements as they are secured under our reserve-based credit facilities.

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The following tables summarize, for the periods indicated, our hedges currently in place through December 31, 2013.

These derivatives settle on a combination of NYMEX and Inside FERC prices for CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), Panhandle Eastern Pipeline (Texas, Oklahoma), and Southern Star Central Gas Pipeline (Texas, Oklahoma, and Kansas) and are accounted for as cash flow hedges at December 31, 2008:

Fixed Price Swaps NYMEX

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2009	2,887,500	$ 8.40	2,903,750	$ 8.40	2,920,000	$ 8.40	2,920,000	$ 8.40	11,631,250	$ 8.40
2010	2,340,000	$ 8.06	2,360,000	$ 8.06	2,380,000	$ 8.06	2,380,000	$ 8.06	9,460,000	$ 8.06
2011	1,800,000	$ 8.37	1,820,000	$ 8.37	1,840,000	$ 8.37	1,840,000	$ 8.37	7,300,000	$ 8.37
2012	1,592,500	$ 8.32	1,592,500	$ 8.32	1,610,000	$ 8.32	1,610,000	$ 8.32	6,405,000	$ 8.32
									34,796,250	

Basis Swaps Various Indexes

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
2009	1,687,500	$ 1.02	1,701,250	$ 1.02	1,527,750	$ 1.03	1,431,000	$ 1.03	6,347,500	$ 1.03
2010	1,062,000	$ 1.00	1,064,500	$ 1.00	869,000	$ 1.00	770,000	$ 1.00	3,765,500	$ 1.00
									10,113,000	

Fixed Price Cash Flow Swaps CenterPoint Energy Gas Transmission (East)

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2009	112,500	$ 8.11	113,750	$ 8.11	115,000	$ 8.11	115,000	$ 8.11	456,250	$ 8.11
2010	90,000	$ 7.91	90,000	$ 7.91	90,000	$ 7.91	90,000	$ 7.91	360,000	$ 7.91
2011	90,000	$ 7.93	90,000	$ 7.93	90,000	$ 7.93	90,000	$ 7.93	360,000	$ 7.93
									1,176,250	

These derivatives settle on a combination of NYMEX and Inside FERC prices for CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), Panhandle Eastern Pipeline (Texas, Oklahoma), and Southern Star Central Gas Pipeline (Texas, Oklahoma, and Kansas) and are accounted for as mark-to-market activities at December 31, 2008:

Put Options NYMEX

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2009	120,000	$ 8.83	120,000	$ 7.50	120,000	$ 7.50	40,000	$ 7.50	400,000	$ 7.90
									400,000	

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MTM Fixed Price Swaps NYMEX

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2009	430,000	$ 10.68	297,500	$ 9.93	170,000	$ 9.43	40,000	$ 6.24	937,500	$ 10.03
2010	610,000	$ 9.28	515,000	$ 9.01	290,000	$ 8.69	320,000	$ 8.80	1,735,000	$ 9.02
2011	600,000	$ 9.12	605,000	$ 9.12	380,000	$ 8.88	380,000	$ 8.88	1,965,000	$ 9.03
2012	635,000	$ 8.38	635,000	$ 8.38	640,000	$ 8.38	640,000	$ 8.38	2,550,000	$ 8.38
2013	450,000	$ 9.16	455,000	$ 9.16	460,000	$ 9.16	460,000	$ 9.16	1,825,000	$ 9.16
									9,012,500	

MTM Fixed Price Basis Swaps Various Indexes

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
2009	600,000	$ 0.96	605,000	$ 0.96	610,000	$ 0.96	610,000	$ 0.96	2,425,000	$ 0.96
2010	285,000	$ 1.00	287,500	$ 1.00	290,000	$ 1.00	290,000	$ 1.00	1,152,500	$ 1.00
2011	1,050,000	$ 0.78	1,060,000	$ 0.78	840,000	$ 0.78	840,000	$ 0.78	3,790,000	$ 0.78
2012	1,090,000	$ 0.65	1,090,000	$ 0.65	1,100,000	$ 0.65	1,100,000	$ 0.65	4,380,000	$ 0.65
									11,747,500	

MTM Fixed Price Swaps CenterPoint Energy Gas Transmission (East)

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2009	112,500	$ 8.11	113,750	$ 8.11	115,000	$ 8.11	115,000	$ 8.11	456,250	$ 8.11
2010	90,000	$ 7.91	90,000	$ 7.91	90,000	$ 7.91	90,000	$ 7.91	360,000	$ 7.91
2011	90,000	$ 7.93	90,000	$ 7.93	90,000	$ 7.93	90,000	$ 7.93	360,000	$ 7.93
									1,176,250	

In February 2009, the company entered into these derivatives that settle on Inside FERC prices for ONEOK Gas Transportation (Oklahoma) and will be accounted for as mark-to-market activities:

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2010	225,000	$ 0.75	227,500	$ 0.75	230,000	$ 0.75	230,000	$ 0.75	912,500	$ 0.75
2011	285,000	$ 0.74	287,500	$ 0.74	290,000	$ 0.74	290,000	$ 0.74	1,152,500	$ 0.74

2012	60,000	$ 0.73	60,000	$ 0.73	60,000	$ 0.73	60,000	$ 0.73	240,000	$ 0.73
									2,305,000	

Investing Activities Acquisitions and Capital Expenditures

Cash used in investing activities was $95.0 million for the year ended December 31, 2008, compared to $502.5 million for the same period in 2007. Our capital expenditures were $95.9 million in 2008, which primarily related to $47.9 million for drilling and development of oil and natural gas properties and $50.3 million for the CoLa Acquisition offset by $2.2 million in post-closing adjustments related to our 2007 acquisitions in the Cherokee Basin. These post-closing adjustments were primarily related to the receipt of revenues between the effective date of the transaction and the closing date and the receipt of $1.0 million in funds related to the Amvest Acquisition. In 2008, we drilled and completed 15 net wells in the Black Warrior Basin and 100 net wells and 43 net recompletions in the Cherokee Basin. In 2007, we drilled and completed 20 net wells in the Black Warrior Basin, drilled 69 net wells and 21 net recompletions in the Cherokee Basin, and we completed the EnergyQuest, Amvest, and Newfield Acquisitions for $479.4 million, which is net of cash acquired.

Cash used in investing activities was $502.5 million for the year ended December 31, 2007, compared to $25.4 million for the same period in 2006. Our capital expenditures were $23.6 million in cash for the year ended December 31, 2007, which primarily related to drilling and development of oil and natural gas properties and expenditures on materials and supplies. At December 31, 2007, we had $3.7 million in capital expenditures accrued but not paid. During the year ended December 31, 2006, we paid Everlast $2.4 million, which was the remaining balance of the purchase price for the Robinson s Bend assets, and expended $13.5 million on the drilling and development of oil and natural gas properties. In addition, we had $12.4 million of cash flows used in investing activities due to the establishment of a cash pool arrangement with CCG.

We currently anticipate our total capital budget will be between $28.0 million and $33.0 million for the twelve months ending December 31, 2009. This capital budget primarily consists of capital for drilling and also includes amounts for infrastructure projects, equipment, and inventory. The 2009 budget is set at a maintenance capital level and has been reduced from our 2008 spending level of approximately $47.9 million. We expect to spend substantially all of the budget in the Cherokee Basin and have not planned for any investment capital expenditures. As the recent acquisition in the Woodford Shale was for proved developed producing reserves, no material capital expenditures are planned on the wells. We anticipate that as allowed under our limited liability company agreement, maintenance capital associated with production in the Black Warrior Basin and in the Woodford Shale will be redeployed to the Cherokee Basin. We do not currently expect to make any acquisitions in 2009.

The amount and timing of our capital expenditures is largely discretionary and within our control. If natural gas prices decline to levels below acceptable levels, the total borrowing base under our reserve-based credit facilities is reduced, or drilling costs escalate, 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 facilities, and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and crews. Based upon current natural gas price expectations and expected production levels, we anticipate that our cash flow from operations and available borrowing capacity under our reserve-based credit facilities will meet our planned capital expenditures and other cash requirements for the twelve months ending December 31, 2009. However, future cash flows are subject to a number of variables, including the level of natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures. 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 impact our planned capital spending.

Financing Activities

Our net cash provided by financing activities was $6.9 million for the year ended December 31, 2008, compared to $471.2 million provided by financing activities for the same period in 2007. In 2008, we borrowed a net of $59.5 million to fund the CoLa Acquisition, to fund debt issue costs, to finance capital expenditures, and for working capital needs. These net new borrowings occurred under our new reserve-based credit facility secured by our properties outside of Alabama and our amended and restated credit facility secured by properties in Alabama. These two credit facilities are not only secured by our oil and gas properties but also by our operating subsidiaries. We also paid distributions of $50.7 million to our common and Class A unitholders and on the Class D interests in 2008 and incurred $0.3 million in costs associated with our shelf registration statement. We have suspended $1.3 million in quarterly distributions on the Class D interests associated with the periods ended December, 31, 2008, September 30, 2008, June 30, 2008, and March 31, 2008. We expect that these quarterly distributions, and all future quarterly distributions, will remain suspended until the litigation surrounding the Torch NPI is finally resolved. For the year ended December 31, 2008, our distributions to unitholders have exceeded our distributable cash flow such that our distribution coverage ratio is less than 1.0. This coverage ratio compares our distribution rate to our distributable cash flow. Our distributable cash flow reflects Adjusted EBITDA reduced by estimated maintenance capital expenditures and cash interest expense. Our maintenance capital is the amount of capital spending required to maintain our production rates, reserves, and asset base. We have reduced our quarterly distribution rate for the quarter ended December 31, 2008, to $0.13 per unit in order to improve our expected coverage ratio and to provide additional liquidity. For additional information, refer to Outlook on page 73.

For the year ended December, 2007, we borrowed $131.0 million from our reserve-based credit facility in order to fund the EnergyQuest, Amvest, and Newfield Acquisitions. We also paid distributions of $28.6 million to our common and Class A unitholders and on the Class D interests in 2007.

Our net cash provided by financing activities was $471.2 million for the year ended December 31, 2007, compared to $4.0 million provided by financing activities for the same period in 2006. We borrowed $137.0 million from our reserve-based credit facility in order to complete the EnergyQuest, Amvest, and Newfield acquisitions and for investment capital spending in the Black Warrior and Cherokee Basins. We retired $6.0 million in debt in August 2007. We also issued $375.0 million of common units before offering expenses and fees of $5.5 million. We also have paid distributions of $28.6 million to our common and Class A unitholders and on the Class D interests during 2007.

Contractual Obligations

At December 31, 2008, we had the following contractual obligations or commercial commitments:

	Payments Due By Year(1)(2)						
	2009	2010	2011	2012	2013	Thereafter	Total
				(In 000 s)			
Management Services Agreement(3)	$ 1,711	$	$	$	$	$	$ 1,711
Reserve-Based Credit Facilities		212,500					212,500
Support Services Agreement	642						642
Purchase Obligation	2,201						2,201
Total	$ 4,554	$ 212,500	$	$	$	$	$ 217,054

(1) This table does not include any liability associated with derivatives.
(2) This table does not include interest as interest rates are variable. The average interest rate on our outstanding debt was approximately 5.5% in 2008.
(3) The maximum annual amount for charges under the management services agreement approved by the conflicts committee of our board of managers in February 2009 is $1.7 million.

At December 31, 2008, our asset retirement obligation was approximately $6.7 million.

Off-Balance Sheet Arrangements

We have no guarantees or off-balance sheet debt to 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 the recent adverse developments in the global credit markets to limit our potential exposure to credit risk where possible. Our primary credit exposures result from the sale of oil and natural gas and our use of derivatives. Through February 20, 2009, we have not suffered any losses with our counterparties as a result of nonperformance in the current economic and credit crisis.

Certain key counterparty relationships are described below:

CCG

Constellation Energy Commodities Group, Inc. (CCG) purchases a portion of our natural gas production in Oklahoma and Kansas. Through July 31, 2009, we have a guarantee from Constellation for payment of up to $8 million for sales made to CCG. In addition, CCG provided us a letter of credit to secure the payment for natural gas purchases currently for $2.5 million through Wachovia Bank, which expires April 15, 2009. As of February 20, 2009, we have no past due receivables from CCG.

J.P. Morgan Ventures Energy Corporation

J.P. Morgan Ventures Energy Corporation purchases the majority of our natural gas production in Alabama. The payment for the purchases is guaranteed by JP Morgan Chase & Company though October 2009. As of February 20, 2009, we have no past due receivables from J.P. Morgan Ventures Energy Corporation.

Wachovia Bank, N.A.

Wells Fargo & Company (Wells Fargo) acquired Wachovia Bank, N.A., which is a lender that participates in our reserve-based credit facilities. Wachovia represents 14.55% of the maximum credit amount available under our reserve-based facilities which have a combined borrowing base of $265 million as of December 31, 2008. This transaction did not have an impact upon our reserve-based credit facilities. As of February 20, 2009, Wells Fargo had an investment grade credit rating.

Industry Bankruptcies

We have no hedging or other contractual counterparty exposure to Lehman Brothers Holdings Inc., its subsidiaries or its affiliates. We have no credit exposure to SemGroup L.P., its subsidiaries, or its affiliates.

Derivative Counterparties

As of February 20, 2009, all of our derivatives are with BNP Paribas, The Royal Bank of Scotland, and Societe Generale. These banks are lenders who participate in our reserve-based credit facilities. All of our derivatives are collateralized by the assets securing our reserve-based credit facilities. As of February 20, 2009, each of these financial institutions has an investment grade credit rating.

Reserve-Based Credit Facilities

As of February 20, 2009, the banks and their percentage commitments in our two credit facilities are: The Royal Bank of Scotland (23.32%), BNP Paribas (22.55%), Wachovia Bank, N.A. (14.55%), Bank of Nova Scotia (17.00%), Calyon New York Branch (15.05%), and Societe Generale (7.53%). As of February 20, 2009, each of these financial institutions has an investment grade credit rating.

Outlook

During 2009, we expect that our business will continue to be affected by the factors described in Part II, Item 1A. Risk Factors, as well as the following key industry and economic trends. Our expectation is based

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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 2009 Expected Results

Our 2009 business plan and forecast is focused on maintaining net production levels and promoting financial flexibility by enhancing our liquidity position. This plan was prepared in conjunction with the ongoing strategic review undertaken with Tudor, Pickering, Holt & Co. Securities, Inc., our strategic advisor, and has been approved by our Board of Managers. Our goal is to sustain the company through the current business cycle and position our operations for success over the long-term. We expect our full year 2009 results to be impacted by commodity price volatility, financial market instability, ability to access our reserve-based credit facilities, the world-wide economic recession, and uncertainty related to our relationship with Constellation.

We currently anticipate:

- Our production to be between 17.0 Bcfe and 18.5 Bcfe.

- Our operating expenses will be relatively flat with our 2008 operating expenses, resulting in a range of $57.5 million to $63.5 million.

- Our total capital expenditures are expected to be between $28.0 million and $33.0 million, which assumes a decline rate of 13 to 15 percent and a dollar per flowing Mcfe range of $4,400 to $4,600. This capital budget has reduced our anticipated total capital expenditures to a maintenance level of capital expenditures and does not include any investment capital expenditures. We expect to drill and complete between 70 to 75 net wells, primarily in the Cherokee Basin. We will review our drilling and recompletion opportunities and anticipate allocating capital to the highest value-added projects across all of our available opportunities.

- We anticipate that acquisition opportunities will be limited and that there will not be any opportunities to dropdown additional oil and natural gas properties from our sponsor because of the announced sale of its upstream gas properties as market conditions allow. Additionally, we have suspended efforts to enter into partnership arrangements with third parties to develop our large acreage positions in the Cherokee Basin while we work with our strategic advisor to evaluate our strategic options.

- We anticipate that our future distribution levels will be set at a sustainable rate based on our operating results, the market prices for oil and natural gas and our projected business plan being achieved. Our distribution rate for the quarter ended December 31, 2008, was $0.13 per unit. All future quarterly distributions must be approved by our Board of Managers.

Update on Strategic Alternatives

We are currently working with our strategic advisor to analyze various alternatives to enhance unitholder value. At this time, our Board of Managers has determined to initially focus on internal opportunities and to run our business by transitioning our executive management team from being provided under the management services agreement to employees of CEP. We do not intend to disclose developments with respect to this review unless and until the Board of Managers has approved a course of action.

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

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related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of our financial statements. Below, we have provided an expanded discussion of our more critical accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in the preparation of the Consolidated Financial Statements. Please read Note 1 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Natural Gas Properties

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

Depreciation and depletion of producing oil and natural gas properties is recorded based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. SFAS 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, requires that acquisition costs of proved properties be amortized on the basis of all proved reserves, developed and undeveloped, and that capitalized development costs (including wells and related equipment and facilities) be amortized on the basis of proved developed reserves. As more fully described in Note 15 to the consolidated financial statements, proved reserves are estimated by our internal reserve engineers, and are subject to future revisions when additional information becomes available.

As described in the footnotes to the consolidated financial statements, we follow SFAS 143, *Accounting for Asset Retirement Obligations*. Under SFAS 143, estimated asset retirement costs are recognized when the asset is acquired or placed in service, and are amortized over proved reserves using the units-of-production method. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

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

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 natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. Cash flow estimates for the impairment testing are based on third party reserve reports and exclude derivative instruments. Refer to Note 5 to the consolidated financial statements for additional information.

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

Property acquisition costs are capitalized when incurred.

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Oil and Natural Gas Reserve Quantities

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

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

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

Net Profits Interest

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

Revenue Recognition

Sales of natural gas are recognized when 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. 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 gathering or transmission line, quality of natural gas, and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our natural gas contracts are customary in the industry.

Gas imbalances occur when sales are more or less than the entitled ownership percentage of total gas production. Any amount received in excess is treated as a liability. If less than the entitled share of the production is received, the excess is recorded as a receivable. There were no gas imbalance positions at December 31, 2008, 2007 and 2006.

Hedging Activities

We have implemented a hedging policy to hedge a portion of our expected natural gas production for a period of up to five years, as we deem appropriate. To the extent allowed by accounting rules, we account for these hedging activities as cash flow hedges pursuant to SFAS 133.

We use interest rate swaps to mitigate the impact of volatility of changes in the LIBOR interest rate on our interest payments for our debt. We account for these hedging activities as cash flow hedges pursuant to SFAS 133.

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We record changes in the fair value of derivatives designated as hedges that are effective in offsetting the variability in cash flows of forecasted transactions in other comprehensive income until the forecasted transactions occur. At the time the forecasted transactions occur, we will reclassify the amounts recorded in other comprehensive income into earnings. We record the ineffective portion of changes in the fair value of derivatives used as hedges immediately in earnings. When amounts for hedging activities under SFAS 133 are reclassified from Accumulated other comprehensive income (loss) on the balance sheet to the income statement, we record settled natural gas derivatives as Oil and gas sales and settled interest rate swaps as Interest expense (income).

Some of our derivatives do not qualify for hedge accounting but are effective as economic hedges of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Using this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions Risk management assets and Risk management liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of income under the caption Gain / (loss) from mark-to-market activities , which is a component of our total revenues.

Accounting Standards Adopted Through February 20, 2009

In March 2008, the Emerging Issues Task Force reached a consensus on Issue 07-4, or EITF 07-4, Application of the Two-Class Method under FASB Statement 128, Earnings per Share, to Master Limited Partnerships. EITF 07-4 provides guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. This Issue is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted, and the guidance in this Issue is to be applied retrospectively for all financial statements presented. The adoption of this Issue did not have a material impact on our financial statements.

In March 2008, the FASB issued SFAS 161, *Disclosures About Derivative Instruments and Hedging Activities*. SFAS 161 is effective beginning January 1, 2009 and requires entities to provide expanded disclosures about derivative instruments and hedging activities including (1) the ways in which an entity uses derivatives, (2) the accounting for derivatives and hedging activities, and (3) the impact that derivatives have (or could have) on an entity s financial position, financial performance, and cash flows. SFAS 161 requires expanded disclosures and does not change the accounting for derivatives. CEP is currently evaluating the impact of SFAS 161, but we do not expect the adoption of this standard to have a material impact on our financial results.

In December 2007, the FASB issued SFAS 160, Noncontrolling Interests in Consolidated Financial Statements (SFAS 160). SFAS 160 amends Accounting Research Bulletin 51, Consolidated Financial Statements, and requires all entities to report noncontrolling (minority) interests in subsidiaries within equity in the consolidated financial statements, but separate from the parent shareholders equity. SFAS 160 also requires any acquisitions or dispositions of noncontrolling interests that do not result in a change of control to be accounted for as equity transactions. Further, SFAS 160 requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. SFAS 160 is effective for annual periods beginning on or after December 15, 2008. The adoption of SFAS 160 did not have a material impact on our financial statements.

In December 2007, the FASB issued SFAS 141 (revised 2007), Business Combinations (SFAS 141(R)). In SFAS 141(R), the FASB retained the fundamental requirements of Statement 141 to account for all business combinations using the acquisition method (formerly the purchase method) and for an acquiring entity to be identified in all business combinations. However, the new standard requires the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) is effective for annual periods beginning on or after December 15, 2008. The adoption of SFAS 141(R) did not have a material impact on our 2008 financial statements but will impact our future financial statements if we conduct a business combination.

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In April 2007, the FASB issued Staff Position (FSP) FIN 39-1, *Amendment of FASB Interpretation 39.* FSP FIN 39-1 permits an entity to report all derivatives recorded at fair value with any associated fair value cash collateral, which are with the same counterparty under a master netting arrangement, together in the balance sheet. Under the provisions of this FSP, we must either report all derivatives recorded at fair value net with the associated fair value cash collateral or report all derivative amounts gross. The effects of FSP FIN 39-1 must be applied by adjusting all financial statements presented beginning January 1, 2008. FSP FIN 39-1 did not have a material impact on our financial statements.

In February 2007, the FASB issued SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, including an amendment to SFAS 115. Under SFAS 159, entities may elect to measure specified financial instruments and warranty and insurance contracts at fair value on a contract-by-contract basis, with changes in fair value recognized in earnings each reporting period. The election, called the fair value option, enables entities to achieve an offset accounting effect for changes in fair value of certain related assets and liabilities without having to apply complex hedge accounting provisions. SFAS 159 is expected to expand the use of fair value measurement consistent with the FASB s long-term objectives for financial instruments. SFAS 159 is effective as of the beginning of a company s first fiscal year that begins after November 15, 2007. We have assessed the provisions of SFAS 159 and we have elected not to apply fair value accounting to our existing eligible financial instruments. As a result, the adoption of SFAS 159 did not have an impact on our financial statements.

In September 2006, the FASB issued SFAS 157, *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures for fair value measurements. In February 2008, the FASB granted a one-year deferral of the effective date of this statement as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a non-recurring basis. The Statement codifies the definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The standard clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The standard defines the three levels of inputs as 1) observable inputs, 2) inputs other than quoted prices that are observable through corroboration, and 3) unobservable inputs. SFAS 157 is effective for all fair value measurements beginning January 1, 2008. As it relates to our financial assets and liabilities, SFAS 157 did not have a material impact on our financial statements.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2008, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us.

On December 31, 2008, the Securities and Exchange Commission (SEC) issued the final rule, Modernization of Oil and Gas Reporting (Final Rule). The Final Rule adopts revisions to the SEC s oil and gas reporting disclosure requirements and is effective for annual reports on Forms 10-K for years ending on or after December 31, 2009. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments are also designed to modernize the oil and gas disclosure requirements to align them with current practices and technological advances. Revised requirements in the Final Rule include, but are not limited to:

- Oil and gas reserves must be reported using a 12-month average of the closing prices on the first day of each of such months, rather than a single day year-end price;

- Companies will be allowed to report, on a voluntary basis, probable and possible reserves, previously prohibited by SEC rules; and

- Easing the standard for the inclusion of proved undeveloped reserves (PUDs) and requiring disclosure of information indicating any progress toward the development of PUDs.

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We are currently evaluating the potential impact of adopting the Final Rule. The SEC is discussing the Final Rule with the FASB and IASB staffs to align accounting standards with the Final Rule. These discussions may delay the required compliance date. Absent any change in such date, we will begin complying with the disclosure requirements in our annual report on Form 10-K for the year ended December 31, 2009. Voluntary early compliance is not permitted.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

Global Financial and Energy Markets

During 2008, there has been unprecedented volatility in global financial and energy markets. The failures of financial institutions have effectively restricted current liquidity within global financial markets. Despite world-wide governmental efforts to provide liquidity to the financial sector, capital and credit markets currently remain in crisis. We expect that our ability to issue debt and equity will be limited over the next year should capital markets remain in crisis and that the cost of capital may increase during this time. We also may have difficulty in accessing credit should we have the need to. Additionally, the market prices for oil and natural gas have significantly declined since June 2008. This decline may result in a decrease in our total $265 million borrowing base under our reserve-based credit facilities at the next redetermination in mid-2009. The equity valuations for energy-related companies and E&P master limited partnerships in particular, have fallen dramatically. In response to the credit crisis and the decline in the market prices for oil and natural gas, many energy companies have reduced their planned capital expenditures or have shut-in production. Through February 20, 2009, we have announced a reduced distribution level for the quarter ended December 31, 2008, and a lower capital expenditure budget for 2009 as compared to 2008. We do expect that if market prices for oil and natural gas remain depressed, our future cash flows from operations will be reduced for our unhedged production. We will continue to monitor the financial and energy markets to determine if we should revise the timing and scope of our planned drilling programs, financing activities, acquisition activities, and the distribution level to our unitholders to adapt to deteriorating economic conditions.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas production. Realized pricing is primarily driven by the Inside FERC prices for Southern Natural Gas Company (Louisiana) with respect to our properties in the Black Warrior Basin and the Inside FERC prices for CenterPoint Energy Gas Transmission (East), Natural Gas Pipeline Company of America (Midcontinent), the CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), Panhandle Eastern Pipeline (Texas, Oklahoma) and Southern Star Central Gas Pipeline (Texas, Oklahoma, Kansas) with respect to our properties in the Cherokee Basin, and the Inside FERC price for the CenterPoint Energy Gas Transmission (East) for our properties in the Woodford Shale, and the spot market prices applicable to all of our natural gas production. Historically, pricing for natural gas production has been volatile and unpredictable and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside our control, including weather, economic conditions, and the total supply of oil and natural gas for sale in the market.

We have entered into hedging arrangements with respect to a portion of our projected natural gas production through various derivatives that hedge the future prices received. These hedging activities are intended to support natural gas prices at targeted levels and to manage our exposure to natural gas price fluctuations. We do not hold

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or issue derivative instruments for speculative trading purposes. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of the transactions. We attempt to minimize this risk by entering into all of our derivative transactions with counterparties that are lenders in our reserve-based credit facilities. The table below presents the hypothetical changes in fair values arising from potential changes in the quoted market prices of the commodity underlying the derivative instruments used to mitigate these market risks. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the sale of the hedged natural gas production, which are not included in the table. These derivatives do not hedge all of our commodity price risk related to our forecasted sales of natural gas production and as a result, we are subject to commodity price risks on our remaining unhedged natural gas production.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	(Decrease)	Fair Value	Increase
			(in 000 s)		
Impact of changes in commodity prices on derivative commodity instruments December 31, 2008	$ 72,998	$ 45,547	$ (27,451)	$ 100,358	$ 27,360

Interest Rate Risk

At December 31, 2008, we had debt outstanding of $212.5 million. Of this amount, $44.0 million incurred interest at a rate of a one-month LIBOR rate and $168.0 million incurred interest at a rate of a three-month LIBOR rate, plus an applicable margin of 1.25% and 2.00% based on utilization. An additional $0.5 million incurred interest at an alternative base rate (ABR) of 3.25%, plus an applicable margin of 0.875%. At December 31, 2008, the one-month LIBOR rate was 0.436% and the three-month LIBOR rate was 1.425%, and our applicable margin was 1.875%. At December 31, 2008, the ABR rate was 3.25%, and our applicable margin was 0.875%. At December 31, 2008, the carrying value and fair value of our debt is $212.5 million.

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

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Increase	Fair Value	(Decrease)
			(in 000 s)		
Impact of changes in LIBOR on derivative interest rate instruments December 31, 2008	$ (7,665)	$ (8,646)	$ (981)	$ (6,684)	$ 981

We enter into hedging arrangements to reduce the impact of volatility of changes in the LIBOR interest rate on our interest payments for our debt. At December 31, 2008, we have the following outstanding interest rate swaps that fix our LIBOR rate:

Maturity Date	Total Debt Hedged (in 000 s)	LIBOR Fixed Rate
February 20, 2010	$16,500	4.74%
August 20, 2010	$11,000	4.58%
August 21, 2010	$28,500	2.74%
September 20, 2010	$45,000	4.96%
September 21, 2010	$11,000	2.66%
October 19, 2010	$29,500	4.81%
October 22, 2010	$ 7,500	4.56%
October 22, 2010	$19,000	2.91%

Item 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required to be filed under this item are presented on pages 104 through 145 of this Annual Report on Form 10-K, and are incorporated herein by reference.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The principal executive officer and principal financial officer of Constellation Energy Partners 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, 2008 (the Evaluation Date). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy Partners disclosure controls and procedures are effective.

Changes in Internal Control

During the quarter ended December 31, 2008, there has been no change in Constellation Energy Partners internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that has materially affected, or is reasonably likely to materially affect, Constellation Energy Partners internal control over financial reporting.

Report of Management

Financial Statements

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

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

The Audit Committee of the Board of Managers, which consists of three independent Managers, meets periodically with management, internal auditors, and PricewaterhouseCoopers LLP to review the activities of each in discharging their responsibilities. The internal audit staff and PricewaterhouseCoopers LLP have free access to the Audit Committee.

Management s Report on Internal Control Over Financial Reporting

The management of Constellation Energy Partners LLC (the Company or CEP), under the direction of its 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).

CEP s system of internal control over financial reporting is designed to provide reasonable assurance to CEP s 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.

The management of CEP conducted an evaluation of the effectiveness of CEP s 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 CEP s internal control over financial reporting was effective as of December 31, 2008.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the effectiveness of CEP s internal control over financial reporting at December 31, 2008, as stated in their report on page 104.

Item 9B. Other Information

None.

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PART III

Item 10. Managers, Executive Officers and Corporate Governance

The following table shows information for members of our board of managers and our executive officers as of December 31, 2008. Members of our board of managers are elected for one year terms, and our executive officers will hold office at the discretion of, and may be removed by, our board of managers in its discretion.

Name	Age	Position with Constellation Energy Partners LLC
John R. Collins	51	Chairman of the Board
Stephen R. Brunner	50	Manager, CEO, COO, and President
Richard H. Bachmann	56	Independent manager
Richard S. Langdon	58	Independent manager
John N. Seitz	57	Independent manager
Charles C. Ward	48	Chief Financial Officer and Treasuer

John R. Collins is a member of our board of managers. Mr. Collins also serves as Executive Vice President of Constellation Energy Group, Inc. or Constellation, a position that he has held since July 2007. Mr. Collins also serves as a member of Constellation s Management Committee. Prior to serving in his current position, Mr. Collins was Chief Financial Officer and Executive Vice President of Constellation from July 2007 to October 2008, a Senior Vice President of Constellation from January 2004 to July 2007 and Constellation s Chief Risk Officer from December 2001 until January 2008. Mr. Collins was also Managing Director Finance and Treasurer of Constellation Power Source Holdings, Inc. from January 2000 to December 2001. From February 1997 to December 2001, Mr. Collins served as the senior financial officer of CCG. Mr. Collins currently serves as the Chairman of the Board of the Committee of Chief Risk Officers, an energy industry association of risk management professionals.

Stephen R. Brunner was appointed president and chief executive officer of Constellation Energy Partners in March 2008 and continued to serve in the role of chief operating officer, a role he assumed in February 2008. Mr. Brunner has more than 25 years of experience operating oil and gas properties both domestically and internationally. Prior to joining Constellation Energy Partners, Mr. Brunner also served as a vice president for Constellation Energy Commodities Group, Inc., where he provided support for Constellation Energy Partners in various operational activities. Prior to joining Constellation Energy in February 2008, Mr. Brunner served in various leadership roles at Pogo Producing Company from February 1994 to November 2007 and Zilkha Energy Company from August 1991 to February 1994. Mr. Brunner also held various positions at Chevron Corporation and Tenneco Oil Company prior to 1991.

Richard H. Bachmann is a member of our board of managers and our audit, compensation, conflicts, and nominating and governance committees and chairs our conflicts committee. Mr. Bachmann joined EPCO Inc., a privately held company, in 1999 as Executive Vice President, Chief Legal Officer and Secretary. Prior to joining EPCO Inc., 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. Mr. Bachmann currently serves as a director and as Executive Vice President, Chief Legal Officer and Secretary of various affiliates of EPCO Inc., including Enterprise Products GP, LLC, the general partner of Enterprise Products Partners L.P., a publicly traded midstream energy company, and EPE Holdings LLC, the general partner of Enterprise GP Holdings L.P., a publicly traded midstream energy holding company. Mr. Bachmann also serves as a Director and as President and Chief Executive Officer of the general partner of Duncan Energy Partners L.P., a publicly traded midstream energy company and also an affiliate of EPCO Inc.

Richard S. Langdon is a member of our board of managers and our audit, compensation, conflicts, and nominating and governance committees and chairs our audit committee. Mr. Langdon currently is the President and Chief Executive Officer of Matris Exploration Company, LP, and Sigma Energy Ventures, LLC, each of which is a privately held exploration and production company. From 1997 until 2002, Mr. Langdon served as Executive Vice President and Chief Financial Officer of EEX Corporation, a publicly traded exploration and production company that merged with Newfield Exploration Company in 2002. Prior to that, Mr. Langdon held various positions with the Pennzoil Companies from 1991 to 1996, including Executive Vice President International Marketing Pennzoil Products Company; Senior Vice President Business Development Pennzoil Company; and Senior Vice President Commercial & Control Pennzoil Exploration & Production Company. Langdon also serves as a director of Gasco Energy, Inc., a publicly traded exploration and production company.

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

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

Independence of Board of Managers

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

CEP sold natural gas from the Black Warrior Basin to an affiliate of EPCO Inc. in each of 2008, 2007 and 2006. Mr. Bachman is an executive officer of EPCO Inc. The sales did not exceed 2% of EPCO Inc. s consolidated gross revenues in any of the years.

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

The board of managers has determined that the chairman of the audit committee is an audit committee financial expert as that term is defined in the applicable rules of the SEC. 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. As discussed in *Compensation Discussion and Analysis*, our executive officers are compensated by CCG under the compensation policies of Constellation.

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

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, committee members and committee chairpersons and otherwise taking a leadership role in shaping the corporate governance of our company.

Mr. Seitz is Chairman, and Messrs. Bachmann and Langdon are members.

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

Nominations for Manager

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

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of ownership of our equity securities and reports of changes in ownership of our equity securities with the SEC. Such persons are also required by SEC regulation to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and directors, we believe that during 2008 all Section 16(a) reporting persons complied with all applicable filing requirements in a timely manner.

Certifications

The NYSE Arca 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 Arca s corporate governance listing standards, qualifying the certification to the extent necessary. In accordance with the rules of the NYSE Arca, we provided such a certification within 30 days after our 2008 annual meeting. The certifications of our Chief Executive Officer and Chief Financial officer required by Sections 302 and 906 of the Sarbanes-Oxley Act have been included as exhibits to this Annual Report on Form 10-K.

Item 11. Executive Compensation

Through December 31, 2008, all of our executive officers were employees of Constellation or its affiliates, and they have received no additional compensation from us. During this time, CEPM managed our operations, activities, and employees through the management services agreement under the direction of our board of managers and executive officers. As discussed in Item 13, Certain Relationships and Related Transactions, and Manager Independence Distributions and Payments to CCG, CEPH, CHI and CEPM Payments to CEPM , we reimburse CEPM for direct and indirect general and administrative expenses incurred on our behalf, including the compensation of our executive officers. Each quarter, CEPM charges CEP an amount for services provided to CEP. This amount is agreed to annually and includes a portion of the compensation paid by CEPM and its

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affiliates to personnel who spend time on CEP s business and affairs. The allocation of compensation expense for the chief executive officer, chief financial officer and chief accounting officer is fixed at $150,000 each by agreement between the parties for 2008 and 2007. The allocation of compensation expense for other personnel of CEPM and its affiliates is determined based on the percentage of time spent by such personnel on CEP s business and affairs. The conflicts committee of the Company s board of managers reviews at least annually the services to be provided by CEPM and the costs to be charged to CEP under the management services agreement and reviews the cost allocation quarterly. The conflicts committee also determines if the amounts to be paid by the Company for the services to be performed are fair to and in the best interests of the Company. During the year, the cost allocation may be adjusted upwards to reflect additional services provided by CEPM and its affiliates or downwards to reflect the transition of services to CEP employees.

The following table sets forth the compensation of our named executive officers during 2008 and 2007 for which we have reimbursed CEPM. No reimbursable compensation was paid in 2006.

Name and Principal Position	Year	Salary	Bonus	LTIP Grants	All Other Compensation	Total
Stephen R. Brunner	2008	$ 120,000	$	$	$	$ 120,000
Chief Executive Officer, Chief Operating Officer and President	2007	$	$	$	$	$
Felix J. Dawson[(a)]	2008	$ 30,000	$	$	$	$ 30,000
Chief Executive Officer and President	2007	$ 150,000	$	$	$	$ 150,000
Angela A. Minas[(b)]	2008	$ 30,000	$	$	$	$ 30,000
Chief Financial Officer, Chief Accounting Officer and Treasurer	2007	$ 150,000	$	$	$	$ 150,000
Charles C. Ward	2008	$ 120,000	$	$	$	$ 120,000
Chief Financial Officer and Treasurer	2007	$	$	$	$	$

(a) Effective March 14, 2008, Felix J. Dawson resigned his position and the Board of Managers appointed Steve R. Brunner as President and Chief Executive Officer.

(b) Effective March 14, 2008, Angela A. Minas resigned her position and the Board of Managers appointed Charles C. Ward as Chief Financial Officer and Treasurer.

Transition of the Executive Management Team to CEP

In January 2009, our chief executive officer, chief operating officer, and president, chief financial officer and treasurer, and chief accounting officer and controller, were transitioned from being provided by CEPM under the management services agreement to direct employees of a subsidiary of CEP. In addition, a general counsel was appointed and transitioned from being an employee of CCG. This transition was done to better align our management team with the interests of our unitholders and to increase their focus on our business operations. Employment letter agreements were executed with these employees and were effective January 1, 2009. The details of the letter agreements for our chief executive officer, chief operating officer, and president and our chief financial officer and treasurer were filed as exhibits to a Current Report on Form 8-K on January 7, 2009. During the first quarter 2009, formal employment contracts are expected to be executed and one-time inducement and long-term incentive grants are expected to be completed along with the framework of the team s 2009 annual incentive program.

As part of this transition, the compensation committee of the Board of Managers retained Hewitt Associates LLC to develop and review proposed compensation structures for the management team. Hewitt benchmarked compensation and benefits from among the following list:

a peer group of exploration and production companies, consisting of the following: Callon Petroleum Company, Carrizo Oil & Gas Inc., Delta Petroleum Corp., Edge Petroleum Corp., Goodrich Petroleum Corp., Legacy Reserves LP, McMoRan Exploration Company, Petroquest Energy, Inc., Rosetta Resources, Inc., Venoco, Inc., and Vanguard Natural Resources, LLC.

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Hewitt proposed a compensation mix that would target total direct compensation for the team at competitive market median levels and provide for one-time, inducement sign-on bonuses. The total direct compensation includes a base salary and bonus award payouts based on future performance on selected performance measures. The performance targets will be correlated to the creation of value for CEP unitholders and should balance growth, profitability, and efficient utilization of capital resources. The measures are expected to correspond to the Company s 2009 business plan and may include measures that are commonly used at other comparable E&P companies. The payout against the performance targets will include a threshold level of minimum acceptable performance, a target level of performance, and a maximum level of performance that reflects the achievement of stretch goals. The proposed compensation mix is expected to be heavily weighted to time-based compensation, including restricted units of CEP. To the extent possible, units of CEP will be utilized to further align the interests of the management with unitholders. The overall structure and plan design is expected to be finalized in the first quarter of 2009 and should ensure alignment with our business strategy.

General Counsel Employment Letter Agreement

On December 31, 2008, the Company entered into a letter agreement (the Letter Agreement) with Lisa J. Mellencamp, its General Counsel and Secretary. The Letter Agreement became effective as of January 1, 2009 and states that the Company expects to finalize the terms of employment in an employment agreement to be entered into in early 2009 (the Definitive Agreement). Pursuant to the Letter Agreement, Ms. Mellencamp will receive an annual base salary of $200,000, as well as the right to participate in the Company s Long-Term Incentive Plan and an annual incentive plan that the Company expects to adopt in early 2009.

Under the Letter Agreement, Ms. Mellencamp will (i) be eligible to receive a 2009 annual incentive award equal to 65% of her annual base salary for target-level performance and 130% of her annual base salary for superior performance; (ii) receive a Long-Term Incentive award with an expected value of $300,000 (which may be comprised of both cash and an equity-based award) vesting ratably on a yearly basis (subject to Company performance) over three years and (iii) receive an Inducement Bonus of $400,000 (which may be comprised of both cash and an equity-based award), with 50% of the total value of the Inducement Bonus vesting and becoming payable on each of the first and second anniversaries of the execution of the Definitive Agreement.

Under the Letter Agreements, if, following a change in control event, Ms. Mellencamp s employment is terminated by the Company in an Involuntary Termination or by Ms. Mellencamp in a termination for good reason, the Company will (a) make within 60 days a cash payment of (i) 200% of the then-current Annual Base Salary plus target Annual Incentive, (ii) the then-current Annual Incentive paid out as if Target Level Performance were achieved, prorated on a monthly basis and (iii) the outstanding performance-based Long-Term Incentive, paid out as if Target Level Performance were achieved, prorated on a monthly basis, (b) immediately accelerate vesting of all outstanding service-based Long-Term Incentive awards and Inducement Bonus, (c) continue Ms. Mellencamp s benefits for a one-year period and (d) provide for a full tax gross-up in connection with the items detailed in (a), (b) and (c) above. The Letter Agreement also provides that complete definitions, terms and conditions will be provided in the Definitive Agreement.

A copy of the Letter Agreement is attached as Exhibit 10.22 to this Annual Report on Form 10-K; the summary of the Letter Agreement above is qualified by reference to such exhibit.

Potential Payments Upon Termination or Change In Control

As of December 31, 2008, we do not have any contracts, agreements, plans or arrangements that provide for payments to the named executive officers in connection with any termination of the named executive officers or a change in control of CEP. We expect to enter into formal employment contracts with change of control provisions for our executive management team in the first quarter of 2009.

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Compensation Discussion and Analysis

During 2008 and 2007, we did not directly employ any of the persons responsible for managing our business. Our named executive officers were compensated by CCG under the compensation policies of Constellation. We reimburse CEPM for a portion of the compensation paid to our executive officers by CCG pursuant to our management services agreement. The elements of Constellation s and CCG s compensation program are intended to provide a total compensation package designed to drive performance and reward contributions in support of the business strategies of Constellation and its affiliates. A discussion of Constellation s compensation policies and programs for its executive officers can be found in the proxy statement relating to Constellation s annual meeting of shareholders to be filed by Constellation with the SEC, a copy of which will be available on the SEC s website at *www.sec.gov* or Constellation s website at *www.constellation.com*. For 2008 and 2007, we agreed to reimburse Constellation and CCG under the management services agreement for $150,000 in base salary for each of our named executive officers. Any other compensation, bonus, benefits, incentives, perquisites and other personal benefits paid by Constellation or CCG to our named executive officers were not reimbursed. In 2008 and 2007, we paid no additional remuneration to employees of Constellation and its affiliates who also serve as our executive officers.

We have a compensation committee that consists of three managers who are all independent under the independence standards established by NYSE Arca and SEC rules. The compensation committee will establish and review general policies related to our compensation and benefits. The compensation committee will determine and approve, or make recommendations to the board of managers with respect to, the compensation and benefits of our Chief Executive Officer and our other executive officers. The compensation committee is authorized to retain at company expense any compensation survey, reports on the design and implementation of compensation programs or other services of compensation experts or consultants that it may find necessary in designing, implementing or administering compensation programs. No such experts were retained in 2008 or 2007 or were consulted in relation to our compensation of our named executive officers for those periods.

Long-Term Incentive Plan

We have adopted a long-term incentive plan in 2006. This plan is intended to provide an incentive to our officers, key employees, consultants and managers and those of our affiliates. We expect that this plan should align the interests of those receiving grants with our intention to increase the enterprise value of our company. This incentive program is expected to promote the stability and expansion of our business and to improve operational performance.

The long-term incentive plan permits the grant of awards covering an aggregate of 450,000 common units. We filed a registration statement with the SEC registering the units issuable under the plan. Awards may be issued as common unit grants, restricted common units grants, phantom common unit grants, common unit options grants, or common unit appreciation rights. Through December 31, 2008, we have granted 39,579 restricted common units to our Board of Managers and to certain key employees. The restricted common units vest ratably on a service-based schedule. Of units granted at December 31, 2008, 5,343 have vested and 34,236 are unvested. No other grants have yet been issued to our executive officers issued under the plan, and no specific performance targets, financial measures or operational targets associated with potential grants have yet been developed. We expect to grant certain long-term incentives to our executive officers before the end of 2009 and may have to seek, if required, unitholder approval of an increase in the number of available units under the plan or pursue alternate arrangements.

The plan is administered by the compensation committee of our board of managers. Our board of managers in its discretion may terminate, suspend or discontinue the long-term incentive plan at any time with respect to any award that has not yet been granted. Our board of managers also has the right to alter or amend the long-term incentive plan or any part of the plan from time to time, including increasing the number of common units that may be granted subject to common unitholder approval as required by the exchange upon which the common units are listed at that time. The compensation committee of our board of managers in its discretion may waive any conditions or rights under, amend any terms of, or alter any award, provided, however, no change in any outstanding award may be made that would materially impair the rights of the participant without the consent of the participant.

Compensation of Managers

Officers or employees of Constellation and its affiliates who also serve as our managers will not receive additional compensation for serving as our managers. Each manager will be indemnified by us for actions associated with being a manager to the full extent permitted under Delaware law.

Our compensation committee retained Towers Perrin in 2007 to benchmark our independent managers mix of compensation and amount of each element of compensation to the outside director compensation of various peer groups. Towers Perrin performed the benchmark study using the following benchmark groups:

- a peer group of 10 exploration and production companies, consisting of the following: Clayton Williams Energy Inc., Edge Petroleum Corp., Exploration Company of Delaware Inc., Gasco Energy Inc., GMX Resources Inc., Harvest Natural Resources Inc., McMoRan Exploration Co., Panhandle Oil and Gas Inc., Petroquest Energy Inc. and VAALCO Energy Inc.;
- a general industry group of 326 publicly-traded companies with market capitalizations between $350 million and $1 billion; and
- a peer group of 5 limited partnerships, consisting of the following: Atlas Energy Resources LLC, Copano Energy LLC, Crosstex Energy LP, Linn Energy LLC and Regency Energy Partners LP. Tower Perrin noted in its report that the companies in this peer group varied significantly in size.

Towers Perrin reported the results of its benchmarking study to the chairman of the committee, who shared the results with the other committee members. Our board of managers, based on recommendations from our compensation committee, has approved the following independent, non-employee manager compensation program in 2008:

- $40,000 annual retainer,
- a common unit award with a value of $75,000, which is subject to pro rata forfeiture if board service ceases during the year;
- $2,500 fee for each meeting of the board of managers and each committee meeting attended that occurs on a day when there is no board meeting,
- the chairman of the audit committee will receive an annual retainer of $10,000; and
- reasonable travel expenses to attend meetings.

The annual restricted common unit award with a value of $75,000 is to be granted on March 1 of each year and will have a one-year vesting period. The number of common units granted is computed based on the average closing price of our common units on the NYSE Arca for the 20 trading days through the date of grant, rounded to the nearest unit. Distributions on the restricted common units are made at the time such distributions are made to other holders of common units.

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The following table sets forth a summary of the 2008 manager compensation:

Director Compensation

Name	Fees Earned or paid in Cash $	Stock Awards ($)(1)	Option Awards ($)	Non Equity Incentive Plan Compensation ($)	Change in Pension Value and NonQualified Deferred Compensation Earnings ($)	All Other Compensation ($)(2)	Total ($)
Richard H. Bachmann	$ 75,000	$ 89,298	$	$	$	$ 8,816	$ 173,114
Richard S. Langdon	$ 87,500	$ 89,298	$	$	$	$ 8,253	$ 185,051
John N. Seitz	$ 75,000	$ 89,298	$	$	$	$ 8,253	$ 172,551

(1) Represents the compensation expense recognized in 2008 pursuant to SFAS 123R relating to a restricted common unit award granted to each manager on March 1, 2008. The grant date fair value of each manager s stock award was $75,000. At December 31, 2008, Mr. Langdon and Mr. Seitz held 1,781 common units and 3,668 unvested restricted common units and Mr. Bachmann held 1,781 common units and 4,668 unvested restricted common units.

(2) All other compensation represents distributions received on unvested restricted common units.

In 2009, the Managers are expected to receive the same compensation package as in 2008.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serves as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of our board of managers or compensation committee. The members of our compensation committee are John N. Seitz, Richard H. Bachmann, and Richard S. Langdon. None of these individuals are former employees of CEP.

Compensation Committee Report

The compensation committee of the board of managers has reviewed and discussed the *Compensation Discussion and Analysis* beginning on page 89 with management. Based on such review and discussions, the compensation committee recommended to the board of managers that the *Compensation Discussion and Analysis* be included in this Annual Report on Form 10-K.

John N. Seitz, Chairman

Richard H. Bachmann

Richard S. Langdon

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

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

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

our managers and 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

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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 22,386,063 units outstanding. Except as indicated by footnote, to our knowledge the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable. The address of all of our managers and executive officers is c/o Constellation Energy Partners LLC, 100 Constellation Way, Baltimore, Maryland 21202. Ownership amounts are as of February 20, 2009.

	Common Units Beneficially Owned		Class A Units Beneficially Owned		Percentage of Total Units
Name of Beneficial Owner	**Number**	**Percentage**	**Number**	**Percentage**	**Percentage**
Constellation Energy Group, Inc.[1]	5,918,894	27.0%	447,721	100%	28.4%
Constellation Energy Partners Holdings, LLC[2]	5,918,894	27.0%	447,721	100%	28.4%
Constellation Energy Partners Management, LLC[3]			447,721	100%	2.0%
GPS Partners LLC[4]	1,778,732	8.1%			7.9%
Barclays PLC.[5]	1,106,185	5.0%			4.9%
Richard H. Bachmann[6]	6,449	*			*
Stephen R. Brunner					
John R. Collins					
Michael B. Hiney					
Richard S. Langdon[6]	5,449	*			*
Lisa J. Mellencamp					
John N. Seitz[6]	5,449	*			*
Charles C. Ward					
Felix J. Dawson[7]					
Angela A. Minas[8]					
All managers and executive officers as a group (7 persons)	17,347	*			*

* Less than 1%

(1) Constellation Energy Group, Inc., through its direct and indirect ownership of Constellation Enterprises, Inc., Constellation Holdings, Inc. and Constellation Power Source Holdings, Inc., is the ultimate parent company of Constellation Energy Partners Holdings, LLC and Constellation Energy Partners Management,
LLC and may, therefore, be deemed to beneficially own the Common Units held by Constellation Energy Partners Holdings, LLC and the Class A units held by Constellation Energy Partners Management, LLC. The address of Constellation Energy Group, Inc. is 100 Constellation Way, Baltimore, MD 21202.

(2) Constellation Energy Partners Holdings, LLC is the parent company of Constellation Energy Partners Management, LLC and may, therefore, be deemed to beneficially own the Class A units held by Constellation Energy Partners Management, LLC. The address of Constellation Energy Partners Holdings, LLC is 100 Constellation Way, Baltimore, MD 21202.

(3) The address of Constellation Energy Partners Management, LLC is 100 Constellation Way, Baltimore, MD 21202.

(4) Based on Schedule 13G dated January 9, 2009, Brett S. Messing is the control person of GPS Partners LLC. The address of GPS Partners LLC is 2120 Colorado Ave. Suite 250, Santa Monica, California 90404.

(5) Based on Form SC 13G/A Holdings Report filed by Barclays PLC on January 29, 2009. The address of Barclays PLC is 1 Churchill Place, London, E14 5HP, England.

(6) Includes unvested restricted Common Unit awards issued on March 1, 2008. The grant date fair value of each manager s stock award was $75,000. These restricted Common Units will vest in full on March 1, 2009. The grant of restricted Common Units forfeits on a pro rata basis if service as a manager terminates prior to the vesting date of March 1, 2009.

(7) Effective March 14, 2008, Felix J. Dawson resigned his position and the Board of Managers appointed Steve R. Brunner as President and Chief Executive Officer.

(8) Effective March 14, 2008, Angela A. Minas resigned her position and the Board of Managers appointed Charles C. Ward as Chief Financial Officer and Treasurer.

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Equity Compensation Plan Information

The following table reflects our equity compensation plan information as of December 31, 2008:

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		$	410,421
Total		$	410,421

See Item 11. *Executive Compensation Long-Term Incentive Plan* for a description of the material features of our long-term incentive plan.

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

Constellation owns a significant number of our units. As of February 20, 2008, CEPM owns all 447,721 of our Class A units, and all of the management incentive interests; Constellation Energy Partners Holdings, LLC, or CEPH, owns 5,918,894 common units; and Constellation Holdings, Inc., or CHI, owns all of our Class D interests. Each of CEPM, CEPH and CHI is a wholly owned subsidiary of Constellation. As discussed in *Committees of the Board of Managers Conflicts Committee* , either our board of managers or the board s conflicts committee reviews all related person transactions.

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

Distributions and Payments to CEPH, CHI and CEPM

The following summarizes the distributions and payments made or to be made by us to CCG, CEPH, CHI and CEPM in connection with our ongoing operation and any liquidation of us.

Distributions of available cash to CEPM and CEPH

We will generally make cash distributions 98% to common unitholders, including CEPH, and 2% to CEPM in respect of its Class A units. In addition, if distributions exceed the Target Distribution (as defined in our limited liability company agreement) and certain other requirements are met, CEPM will be entitled in respect of its management incentive interests to 15% of distributions above the Target Distribution. For year ended

December 31, 2008, none of these applicable requirements have been met, and, as a result, CEPM was not entitled to receive any management incentive interest distributions. Assuming we have sufficient available cash to pay the current quarterly distribution on all of our outstanding units for four quarters, but no distributions in excess of the full current quarterly distribution of $0.13 per unit, CEPM would receive an annual distribution of approximately $0.2 million on its Class A units and CEPH would receive an annual distribution of approximately $3.1 million on its common units.

Distributions to CHI

For each full calendar quarter during the period commencing January 1, 2007 and ending on December 31, 2012 that the sharing arrangement in respect of the calculation of amounts payable to Torch Energy Royalty Trust for the non-operating net profits interest remains in effect, we will distribute to CHI, in respect of its Class D interests, approximately $0.3 million, as a partial return of the $8.0 million capital contribution made for the Class D interests, which payment will be made concurrently with the quarterly cash distribution to our common and Class A unitholders for that quarter. Unless the special distribution right has been terminated earlier, the Class D interests will be cancelled upon the payment of the final distribution of approximately $0.3 million to CHI for the quarter ending December 31, 2012. If the amounts payable by us to the Trust are not calculated based on the sharing arrangement through December 31, 2012, unless such change is approved in advance by our board of managers and our conflicts committee, the special distribution right for future quarters will terminate. In the case of such early termination, CHI will only have the right under specific circumstances upon our liquidation to receive the unpaid portion of the $8.0 million capital contribution that has not then been distributed to CHI in such special distributions. If the special distribution right is terminated during a quarter, the special distribution in respect of the Class D interests will be prorated for that quarter based upon the ratio of the number of days in such quarter prior to the effective date of such termination to 90.

In connection with the initiation of certain legal proceedings involving the Trust, during 2008 the special quarterly cash distributions with respect to the Class D interests totaling $1.3 million were suspended for the three month periods ended December 31, 2008, September 30, 2008, June 30, 2008, and March 31, 2008. To date, distributions of approximately $1.3 million have been paid to CHI, as holder of the Class D interests.

Payments to CEPM

Each quarter, CEPM charges us an amount for services provided to us pursuant to our management services agreement. This amount is agreed to annually and includes a portion of the compensation paid by CEPM and its affiliates to personnel who spend time on our business and affairs. During 2008, the allocation of compensation expense for the chief executive officer, chief financial officer and chief accounting officer was fixed by agreement between the parties. The allocation of compensation expense for other personnel of CEPM and its affiliates is determined based on the percentage of time spent by such personnel on our business and affairs. The conflicts committee of our board of managers reviews at least annually the services to be provided by CEPM and the costs to be charged to us under the management services agreement and reviews the cost allocation quarterly. The conflicts committee also determines if the amounts to be paid by us for the services to be performed are fair to and in our best interests. During the year, the cost allocation may be adjusted upwards to reflect additional services provided by CEPM and its affiliates or downwards to reflect the transition of services to our employees. The costs charged to us under the management services agreement may be greater or less than the actual costs we would incur if the services were performed by an unaffiliated third party. For the year ended December 31, 2008, and 2007, approximately $2.9 million and $1.4 million in costs were incurred under this agreement, respectively.

In 2009, as discussed in Transition of the Executive Management Team to CEP on page 87, our executive management team was transitioned from being provided by CEPM under the management services agreement to become employees of CEP. As a result, the reimbursement of fixed compensation costs to CEPM for these employees will no longer occur in 2009 and the full compensation of our executive management team will be borne by CEP.

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Conversion of Class A units and management incentive interests

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

Liquidation

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

Transactions with Affiliates

Omnibus Agreement

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

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

We have made a claim under the Omnibus Agreement to CCG as a result of the litigation with respect to the Torch NPI calculation for periods prior to our initial public offering. See Torch Royalty NPI beginning on page 15 for additional information.

Management Services Agreement

In connection with our initial public offering, we entered into a management services agreement with CEPM. Under this management services agreement, we may request that CEPM or its designee provide legal, accounting, audit, tax, financial and risk management services. Upon our request, CEPM will also provide us with engineering, geological, geophysical, property management and project management services. CEPM may provide us with acquisition services upon our request, but is not obligated to do so. As a result, CEPM will have no commitment to offer us any particular E&P property, whether from CEPM or its other affiliates or a third party.

Competition

None of CEPM, Constellation, CCG or any of their affiliates will be restricted under the management services agreement from competing with us. CEPM, Constellation, CCG and any of their affiliates may acquire or dispose of any assets, including, among other things, oil and natural gas exploration and production properties, in the future without any obligation to offer us the opportunity to purchase those assets.

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Reimbursement of Costs

Subject to the arrangements relating to acquisition services described above and as discussed further in *Distributions and Payments to CCG, CEPH, CHI and CEPM Payments to CEPM* , CEPM will be entitled to be reimbursed on a quarterly basis for all supervisory and management costs incurred by it in performing services for us. These costs and expenses will be deducted from cash available for distribution to our unitholders. For 2008 and 2007, these costs were approximately $2.9 million and $1.4 million, respectively. For 2009, we expect these costs to not exceed approximately $1.7 million.

Review by Our Board of Managers

Our board of managers has the right to evaluate CEPM s performance under the agreement and, if considered desirable by our board of managers, arrange for third parties to provide some or all of the services to be provided pursuant to the management services agreement.

Standard of Care

In exercising its powers and discharging its duties under the management services agreement, CEPM is required to act in good faith, and is to exercise that degree of care, diligence and skill that a reasonably prudent advisor or manager, as the case may be, would exercise in comparable circumstances.

Indemnification

The management services agreement provides that, except arising out of our gross negligence, intentional misconduct or a breach of the agreement, CEPM must indemnify us for any damages, liabilities, costs and expenses (including reasonable attorneys fees) arising from the rendering of CEPM s services under the management services agreement. We will indemnify CEPM for damages, liabilities, costs and expenses (including reasonable attorneys fees) arising from our gross negligence, willful misconduct or breach of this agreement.

Term and Termination

The management services agreement is in effect for continuous one-year terms, with each term ending on December 31. The management services agreement may be terminated by us or CEPM at any time and for any reason upon six months advance notice to the other party. To date, neither party has given notice to terminate the management services agreement.

Amendments

The management services agreement may not be amended without the prior approval of the conflicts committee of our board of managers if the proposed amendment will, in the reasonable discretion of our board of managers, adversely affect holders of our common units.

Trademark License

In connection with our initial public offering, Constellation granted a limited license to us for the use of certain trademarks in connection with our business. The license will terminate upon the elimination of the right of the holder or holders of our Class A units to elect the Class A managers pursuant to our limited liability company agreement. Constellation will indemnify us from any third-party claims alleging trademark infringement that may arise out of our use of the Constellation trademarks under the license.

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Credit Support Fee Agreements

In connection with certain of our acquisitions, Constellation entered into credit support agreements with us to provide guarantees to three banks that required credit support for certain financial derivatives. These guarantees were obtained because we did not own the assets at the time the derivatives were entered into and we could not use our existing reserve-based credit facility to provide collateral for the derivative transactions.

- In February 2008, in connection with the CoLa Acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $8.5 million for certain financial derivatives that we entered into with BNP Paribas (BNP) and Societe Generale (SocGen). These guarantees have been released.

- In August 2007, in connection with the Newfield acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $10.0 million for certain financial derivatives that we entered into with BNP. This guarantee has been released.

- In July 2007, in connection with the Amvest acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $15.0 million for certain financial derivatives that we entered into with BNP. This guarantee has been released.

- In March 2007, in connection with the EnergyQuest acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $11.5 million for certain financial derivatives that we entered into with BNP. This guarantee has been released.

- In March 2007, in connection with the EnergyQuest acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $25 million for certain financial derivatives that we entered into with The Royal Bank of Scotland plc (RBS). This guarantee has been released.

We have paid Constellation $0.8 million for the credit support described above.

Item 14. Principal Accountant Fees and Services

We engaged our principal accountant, PricewaterhouseCoopers LLP to audit our financial statements and perform other professional services for the fiscal years ended December 31, 2008 and 2007.

Audit Fees. The aggregate fees billed for the financial statement audit or services provided in connection with statutory or regulatory filings for the years ending 2008 and 2007 were $1,009,500 and $1,212,000, respectively.

Audit-Related Fees. The aggregate audit-related fees billed by PricewaterhouseCoopers for the years ending 2008 and 2007 were $0 and $496,491, respectively. The 2007 audit-related fees were billed in connection with the EnergyQuest and Newfield acquisitions.

Tax Fees. The aggregate fees related to the preparation of K-1 statements for the years ending 2008 and 2007 were $467,017 and $535,000, respectively.

All Other Fees. There were no other fees billed by our principal accountant for the years ending 2008 and 2007 for services other than those described above.

Audit Committee Pre-Approval Policies and Practices

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

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

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

1. Financial Statements:

Reports of Independent Registered Public Accounting Firm dated February 27, 2009 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Income (Loss) Constellation Energy Partners LLC for the three years ended December 31, 2008

Consolidated Balance Sheets Constellation Energy Partners LLC at December 31, 2008 and December 31, 2007

Consolidated Statements of Cash Flows Constellation Energy Partners LLC for the three years ended December 31, 2008

Consolidated Statements of Changes in Members Equity Constellation Energy Partners LLC for the three years ended December 31, 2008

Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

Schedule II Valuation and Qualifying Accounts

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

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

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC and Constellation Energy Partners, LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007).
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).
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).
2.4	Purchase and Sale Agreement dated as of August 2, 2007, between Newfield Exploration Mid-Continent Inc. and Constellation Energy Partners LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
2.5	Nominee Agreement, dated as of September 21, 2007, by and between Newfield Exploration Mid-Continent Inc. and CEP Mid-Continent LLC (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).

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Exhibit Number	Description
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)
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)
3.3	Amendment No. 1 to 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 April 24, 2007)
3.4	Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC dated July 25, 2007. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
3.5	Amendment No. 3 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC dated September 21, 2007 (incorporated by reference to Exhibit 3.5 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
4.1	Registration Rights Agreement, dated as of April 23, 2007, by and between Constellation Energy Partners LLC and the Purchasers named therein (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007).
4.2	Registration Rights Agreement, dated July 25, 2007, by and between Constellation Energy Partners LLC and the purchasers named therein. (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
4.3	Registration Rights Agreement, dated September 21, 2007, by and between Constellation Energy Partners LLC and the purchasers named therein (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007)
10.1	Credit Agreement dated as of October 31, 2006 by and among Constellation Energy Partners LLC, as borrower, The Royal Bank of Scotland plc, as administrative agent, RBS Securities Corporation, as lead arranger and sole bookrunner, BNP Paribas and Wachovia Bank N.A., as co-syndication agents and the lenders from time to time party thereto (incorporated herein by reference to Exhibit 10.1 to Amendment No. 4 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on November 2, 2006 (Amendment No. 4))
10.2	Management Services Agreement dated as of November 20, 2006 by and between Constellation Energy Partners LLC and Constellation Energy Partners Management, LLC (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.3	Omnibus Agreement dated as of November 20, 2006 by and among Constellation Energy Partners LLC, Constellation Energy Commodities Group, Inc., Robinson s Bend Production II, LLC, Robinson s Bend Operating II, LLC and Robinson s Bend Marketing II, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.4	Net Overriding Royalty Conveyance dated as of November 22, 1993 but effective as of October 1, 1993, pursuant to Part I thereof, from Velasco Gas Company, Ltd. to Torch Energy Advisors Incorporated, and pursuant to Part II thereof, from Torch Energy Advisors Incorporated to the Torch Energy Royalty Trust (incorporated herein by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on September 29, 2006 (Amendment No. 2))

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Exhibit Number	Description
10.5	Oil and Gas Purchase Agreement dated as of October 1, 1993 by and among Torch Energy Marketing, Inc., Torch Royalty Company and Velasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2)
10.6	Letter agreement dated as of June 13, 2005 by and between Robinson s Bend Marketing II, LLC and Torch Energy TM, Inc. (incorporated herein by reference to Exhibit 10.6 to Amendment No. 2)
10.7	International Swap Dealers Association, Inc. Master Agreement and Schedule dated as of June 16, 2006 between The Royal Bank of Scotland, plc and Constellation Energy Resources LLC (incorporated herein by reference to Exhibit 10.7 to Amendment No. 2)
10.8	Confirmation, dated June 28, 2006, effective June 20, 2006, between The Royal Bank of Scotland, plc and Constellation Energy Resources LLC (incorporated herein by reference to Exhibit 10.8 to Amendment No. 2)
10.9	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)
10.10	Letter agreement as of October 24, 2006 by and among The Investment Company LLC, Constellation Energy Commodities Group, Inc. and Robinson s Bend Production II, LLC (incorporated herein by reference to Exhibit 10.10 to Amendment No. 4)
10.11	Trademark License Agreement dated as of November 20, 2006 by and between Constellation Energy Group, Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.12	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)
10.13	Class E Unit and Common Unit Purchase Agreement, dated as of March 8, 2007, by and among Constellation Energy Partners LLC and the Purchasers named therein (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007).
10.14	First Amendment to Credit Agreement, dated as of April 4, 2007, by and among Constellation Energy Partners LLC and the Lenders signatory thereto (incorporated herein by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on May 10, 2007).
10.15	Class F Unit and Common Unit Purchase Agreement, dated July 12, 2007, by and between Constellation Energy Partners LLC and the purchasers named therein. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
10.16	Common Unit Purchase Agreement, dated August 2, 2007, by and between Constellation Energy Partners LLC and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
10.17	Water Gathering and Disposal Agreement by and among Torch Energy Associates Ltd., a Texas limited partnership, and Velasco Gas Company Ltd., a Texas limited partnership, dated August 9, 1990.

Exhibit Number	Description
10.18	First Amendment to Water Gathering and Disposal Agreement by and among Torch Energy Associates Ltd., a Texas limited partnership, and Velasco Gas Company Ltd., a Texas limited partnership, dated October 1, 1993.
10.19	Second Amendment to Water Gathering and Disposal Agreement, by and among Robinson s Bend Operating Company, LLC, a Delaware company, successor in interest to Torch Energy Associates Ltd., a Texas limited partnership, and Everlast Energy LLC, a Delaware company, successor in interest to Velasco Gas Company Ltd., a Texas limited partnership, dated November 30, 2004.
10.20	LetterAgreement dated December 31, 2008 between Constellation Energy Partners LLC and Stephen R. Brunner
10.21	LetterAgreement dated December 31, 2008 between Constellation Energy Partners LLC and Charles C. Ward.
*10.22	LetterAgreement dated December 31, 2008 between Constellation Energy Partners LLC and Lisa J. Mellencamp.
*10.23	Explorationand Development Agreement
*10.24	Substitutedand Replaced First Amendment to the Exploration and Development Agreement
*10.25	Assignment,Assumption and Ratification Agreement under the Exploration and Development Agreement
*10.26	ClarificationAgreement to the Credit Agreements, dated as of February 24, 2009, by and among Constellation Energy Partners LLC and the Lenders Signatory thereto.
*12.1	Computation of Ratio of Earnings to Fixed Charges
*21.1	List of subsidiaries of Constellation Energy Partners LLC
*23.1	Consent of PricewaterhouseCoopers LLP
*23.2	Consent of Netherland, Sewell & Associates, Inc.
*31.1	Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

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REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations and comprehensive income (loss), of cash flows, and of changes in members equity present fairly, in all material respects, the financial position of Constellation Energy Partners LLC (the Company) (formerly Constellation Energy Resources LLC and CBM Equity IV Holdings, LLC) and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control Over Financial Reporting appearing in Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our audits (which were integrated audits in 2008 and 2007). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes 7 and 17 to the consolidated financial statements, the Company has entered into significant transactions with Constellation Energy Group and its affiliates, a related party.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and managers of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

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Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Houston, Texas
February 27, 2009

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Income (Loss)

	For the year ended December 31, 2008	For the year ended December 31, 2007	For the year ended December 31, 2006
		(In 000 s except unit data)	
Revenues			
Oil and gas sales	$ 141,863	$ 82,725	$ 36,917
(Gain) / Loss from mark-to-market activities (see Note 3)	21,376	(6,856)	
Total revenues	163,239	75,869	36,917
Expenses:			
Operating expenses:			
Lease operating expenses	36,257	17,141	7,234
Cost of sales	7,261	1,788	
Production taxes	8,398	3,646	1,783
General and administrative	14,412	9,109	4,573
(Gain) / Loss on sale of asset	(301)	86	
Depreciation, depletion, and amortization	77,919	23,190	7,444
Accretion expense	411	312	141
Total operating expenses	144,357	55,272	21,175
Other expense / (income)			
Interest expense	12,167	6,930	221
Interest (income)	(350)	(465)	(468)
Other expense (income)	(203)	(109)	
Total other expenses / (income)	11,614	6,356	(247)
Total expenses	155,971	61,628	20,928
Net income	$ 7,268	$ 14,241	$ 15,989
Other comprehensive income (loss)	45,903	(8,889)	13,113
Comprehensive income	$ 53,171	$ 5,352	$ 29,102
Earnings per unit (see Note 1)			
Earnings per unit Basic	$ 0.33	$ 0.87	$ 1.41
Units outstanding Basic	22,350,638	16,321,547	11,320,300
Earnings per unit Diluted	$ 0.33	$ 0.87	$ 1.41
Units outstanding Diluted	22,369,991	16,325,508	11,320,300
Distributions declared and paid per unit	$ 2.25	$ 1.6986	$

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

	December 31, 2008	December 31, 2007
	(In 000 s)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 6,255	$ 18,689
Accounts receivable	9,363	18,519
Prepaid expenses	1,026	554
Risk management assets (see Note 3)	35,587	7,734
Other		377
Total current assets	52,231	45,873
Oil and natural gas properties (See Note 5)		
Natural gas properties, equipment and facilities	769,103	675,144
Material and supplies	4,587	2,880
Less accumulated depreciation, depletion and amortization	(111,171)	(34,371)
Net oil and natural gas properties	662,519	643,653
Other assets		
Debt issue costs (net of accumulated amortization of $1,495 at December 31, 2008 and $443 at December 31, 2007)	1,963	1,449
Risk management assets (see Note 3)	29,746	2,185
Other non-current assets	12,390	13,495
Total assets	$ 758,849	$ 706,655
LIABILITIES AND MEMBERS EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 2,809	$ 1,933
Payable to affiliate	1,043	2,813
Accrued liabilities	10,088	12,315
Environmental liabilities	441	546
Royalty payable	5,125	2,944
Total current liabilities	19,506	20,551
Other liabilities		
Asset retirement obligation	6,754	6,163
Risk management liabilities (see Note 3)		10,539
Debt	212,500	153,000
Total other liabilities	219,254	169,702
Total liabilities	238,760	190,253
Commitments and contingencies (See Note 8)		
Class D Interests	6,667	7,000
Members equity		
Class A units, 447,721 and 447,022 shares authorized, issued and outstanding, respectively	9,266	10,104
Class B units, 22,348,763 and 22,348,763 shares authorized, respectively, and 21,938,342 and 21,904,106 issued and outstanding, respectively	454,029	495,074
Accumulated other comprehensive income	50,127	4,224

Total members equity	513,422	509,402
Total liabilities and members equity	$ 758,849	$ 706,655

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Cash Flows

	CEP		
	For the year ended December 31, 2008	For the year ended December 31, 2007	For the year ended December 31, 2006
		(In 000 s)	
Cash flows from operating activities:			
Net income	$ 7,268	$ 14,241	$ 15,989
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Expenses paid by CCG on behalf of CEP			370
Depreciation, depletion and amortization	77,919	23,190	7,444
Amortization of debt issuance costs	1,052	424	48
Accretion of plugging and abandonment liability	411	312	141
Equity earnings (losses) in affiliate	(203)	(109)	
(Gain) Loss from disposition of property and equipment	(301)	86	
Dryhole costs		209	
Hedge ineffectiveness	(1,189)	1,225	(302)
(Gain) Loss from mark-to-market activities	(21,376)	6,856	
Long-term incentive plan	322	145	
Changes in Assets and Liabilities:			
Change in net risk management assets and liabilities	2,518	(2,935)	
(Increase) decrease in accounts receivable	9,130	(5,560)	(3,785)
(Increase) decrease in prepaid expenses	714	(89)	(255)
(Increase) decrease in other assets	241	(380)	117
Increase (decrease) in accounts payable	875	821	(4,733)
Increase (decrease) in payable to affiliate	(1,770)	(23)	2,456
Increase (decrease) in accrued liabilities	(2,160)	4,789	(2,557)
Increase (decrease) in royalty payable	2,181	(703)	(866)
Net cash provided by operating activities	75,632	42,499	14,067
Cash flows from investing activities:			
Cash paid for acquisitions, net of cash required	(48,063)	(479,391)	(261)
Development of natural gas properties	(47,897)	(23,645)	(13,224)
Proceeds from sale of equipment	599	188	
Distributions from equity affiliate	353	315	
Investment in affiliate cash pool			(12,419)
Other, net			475
Net cash used in investing activities	(95,008)	(502,533)	(25,429)
Cash flows from financing activities:			
Members distributions	(50,656)	(28,604)	(122,750)
Proceeds from issuance of debt	237,000	137,000	30,000
Repayment of debt	(177,500)	(6,000)	(8,063)
Costs for shelf registration statement	(340)		
Proceeds from equity issuance		369,549	109,340
Initial public offering issue costs			(3,325)
Debt issue costs	(1,562)	(707)	(1,186)

Net cash provided by financing activities		6,942		471,238		4,016
Net (decrease) increase in cash		(12,434)		11,204		(7,346)
Cash and cash equivalents, beginning of period		18,689		7,485		14,831
Cash and cash equivalents, end of period	$	6,255	$	18,689	$	7,485
Supplemental disclosures of cash flow information:						
Change in accrued capital expenditures	$	(124)	$	3,680	$	353
Cash received during the period for interest	$	372	$	443	$	
Cash paid during the period for interest	$	10,545	$	5,935	$	3

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Changes in Members Equity

	Members Equity	Class A Units	Class A Amount	Class B Units	Class B Amount	Accumulated Other Comprehensive Income	Total Members Equity
			(In 000 s, except unit data)				
Balance, December 31, 2005	$ 169,167		$		$	$	$ 169,167
Contributions	571						571
Distributions	(122,951)						(122,951)
Cash in exchange for Floyd Shale rights	475						475
Issuance of common units, net of issue costs of $3,325	(47,458)	226,406	2,910	11,093,894	142,563		98,015
Termination of cash pool	(12,419)						(12,419)
Change in fair value of commodity hedges						15,097	15,097
Cash gains on settlement of commodity hedges						(2,114)	(2,114)
Change in fair value of interest rate hedges						130	130
Net income	12,615		67		3,307		15,989
Balance, December 31, 2006	$	226,406	$ 2,977	11,093,894	$ 145,870	$ 13,113	$ 161,960
Distributions			(552)		(27,052)		(27,604)
Issuance of common units, net of issue costs of $5,465		220,616	7,392	10,810,212	362,157		369,549
Long-term incentive program			3		142		145
Change in fair value of commodity hedges						7,372	7,372
Cash gains on settlement of commodity hedges						(13,458)	(13,458)
Change in fair value of interest rate hedges						(2,803)	(2,803)
Net income			284		13,957		14,241
Balance, December 31, 2007	$	447,022	$ 10,104	21,904,106	$ 495,074	$ 4,224	$ 509,402
Distributions			(1,008)		(49,315)		(50,323)
Change in fair value of commodity hedges						48,966	48,966
Cash settlement of commodity hedges						1,929	1,929
Change in fair value of interest rate hedges						(4,992)	(4,992)
Long-term incentive program		699	7	34,236	315		322
Contributions			17		833		850
Net income			145		7,123		7,268
Balance, December 31, 2008	$	447,721	$ 9,265	21,938,342	$ 454,030	$ 50,127	$ 513,422

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2008, 2007 and 2006

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Basis of Presentation

CBM Equity IV Holdings, LLC was organized as a limited liability company on February 7, 2005, under the laws of the State of Delaware and had no principal operations prior to the acquisition of our properties in the Black Warrior Basin on June 13, 2005. On May 10, 2006, CBM Equity IV Holdings, LLC changed its name to Constellation Energy Resources LLC. On July 18, 2006, Constellation Energy Resources LLC changed its name to Constellation Energy Partners LLC (CEP or the Company). CEP completed its initial public offering on November 20, 2006, and is traded on the NYSE Arca under the symbol CEP . CEP is partially-owned by Constellation Energy Commodities Group, Inc. (CCG), which is owned by Constellation Energy Group, Inc. (NYSE: CEG) (Constellation or CEG). As of December 31, 2008, affiliates of Constellation own all of the Company s Class A units, all of the management incentive interests, approximately 27% of the Company s common units, and all of the Company s Class D interests.

The Company is currently focused on the development and acquisition of natural gas properties in the Black Warrior Basin in Alabama, the Cherokee Basin in Kansas and Oklahoma, and the Woodford Shale in Oklahoma (collectively the Oil and Gas Properties). CEP acquired its interests in the Black Warrior Basin in 2005, its interests in the Cherokee Basin in 2007 and its interests in the Woodford Shale in 2008.

Accounting policies used by CEP conform to accounting principles generally accepted in the United States of America. The accompanying financial statements include the accounts of CEP and its wholly-owned subsidiaries (collectively, the Entities). All significant intercompany accounts and transactions have been eliminated in consolidation. CEP operates its oil and natural gas properties as one business segment, the exploration, development and production of natural gas. Management of CEP evaluates performance based on one business segment as there are not different economic environments within the operation of the oil and natural gas properties. Certain reclassifications have been made to prior years reported amounts in order to conform with the current year presentation. These reclassifications did not impact net income, members equity or cash flows.

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash equivalents.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject CEP to a concentration of credit risk consist of cash and cash equivalents, accounts receivable and derivative financial instruments. CEP places their cash with high credit quality financial institutions. CEP places their derivative financial instruments with financial institutions and other firms that its management believes have high credit ratings and participate in the Company s reserve-based credit facilities. Substantially all of CEP s accounts receivables are due from purchasers of oil and natural gas. These sales are generally unsecured. As CEP generally has fewer than 10 large customers for its oil and natural gas sales, CEP routinely assesses the financial strength of its customers. Bad debt expense is recognized on an account-by-account review after all means of collection have been exhausted and recovery is not probable. There has been no bad debt expense for any of the periods presented herein. CEP has no off-balance-sheet credit exposure related to customers.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2008, five customers accounted for approximately 27%, 19%, 15%, 13% and 9%, respectively, of our sales revenues. For the year ended December 31, 2007, five customers accounted for approximately 16%, 14%, 14%, 13% and 8%, respectively, of our sales revenues. For the year ended December 31, 2006, five customers accounted for approximately 30%, 20%, 18%, 17% and 15%, respectively, of our sales revenues.

Oil and Natural Gas Properties

Oil and Natural Gas Properties

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

Depreciation and depletion of producing oil and natural gas properties is recorded 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. Statement of Financial Accounting Standards (SFAS) 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, requires that acquisition costs of proved properties be amortized on the basis of all proved reserves, developed and undeveloped, and that capitalized development costs (including wells and related equipment and facilities) be amortized on the basis of proved developed reserves. As more fully described in Note 15, proved reserves estimates are subject to future revisions when additional information becomes available.

As described in Note 9, CEP follows SFAS 143, *Accounting for Asset Retirement Obligations*. Under SFAS 143, 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 CEP s engineers using existing regulatory requirements and anticipated future inflation rates.

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

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

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

Property acquisition costs are capitalized when incurred.

Support Equipment and Facilities

Support equipment and facilities consist of CEP s 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.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 the Oil and Gas Properties.

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

Oil and Natural Gas Reserve Quantities

CEP s estimate of proved reserves is based on the quantities of natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Proved reserves were calculated based on various factors, including consideration of an independent reserve engineers report on proved reserves and an economic evaluation of all of CEP s properties on a well-by-well basis. The process used to complete the estimates of proved reserves at December 31, 2008, 2007 and 2006 is described in detail in Note 15.

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

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

Derivatives and Hedging Activities

CEP uses derivative financial instruments to achieve a more predictable cash flow from its natural gas production by reducing its exposure to price fluctuations. Additionally, CEP uses derivative financial instruments in the form of interest rate swaps to mitigate its interest rate exposure.

SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, requires that all derivative instruments be 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 unless specific hedge accounting criteria are met. CEP elected to designate these contracts as cash-flow hedges for accounting purposes. The fair value of its derivative contracts is recorded on its balance sheet as Risk management assets and Accumulated other comprehensive income. Changes in the fair value of the cash flow hedges are reflected on the consolidated statements of operations and comprehensive income (loss) as other comprehensive income. When amounts for hedging activities under SFAS 133 are reclassified from Accumulated other comprehensive income (loss) on the balance sheet to the income statement, we record settled natural gas swaps as Gas sales and settled interest rate swaps as Interest expense (income).

Some of our derivatives do not qualify for hedge accounting but are effective as economic hedges of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Using this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions Risk management assets and Risk management liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of income under the caption Gain (loss) from mark-to-market activities , which is a component of our total revenues.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net Profits Interest

Certain of the Properties are subject to a net profits interest (NPI). The NPI represents an interest in production created from the working interest and is based on a contracted revenue calculation (see Note 10). The NPI is accounted for as an overriding royalty interest. This is consistent with how CEP accounts for the NPI for reserves purposes. Any payments made to the NPI holder are reflected as a reduction in revenue.

Revenue Recognition

Sales of oil and natural gas are recognized when oil or natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale are reasonably assured and the sales price is fixed or determinable. Oil and natural gas is sold on a monthly basis. Most of CEP s 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. CEP believes that the pricing provisions of its 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. CEP uses 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, 2008, 2007 or 2006.

Income Taxes

CEP and its wholly-owned subsidiary LLCs are treated as partnerships for federal and state income tax purposes. Essentially all of CEP s 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.

Effective January 1, 2007, CEP implemented FASB Interpretation 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement 109 (FIN 48), which clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements. A company can only recognize the tax position in the financial statements if the position is more-likely-than-not to be upheld on audit based only on the technical merits of the tax position. This accounting standard also provides guidance on thresholds, measurement, derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition that is intended to provide better financial-statement comparability among different companies. CEP performed an evaluation as of January 1, 2007 and concluded that there were no uncertain tax positions requiring recognition in its financial statements. As a result, the adoption of this standard did not have a material impact on CEP s financial position, results of operations or cash flows.

Use of Estimates

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

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

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

Earnings per Unit

The following table presents earnings per common unit amounts computed using SFAS 128:

	Income	Unit	Per Unit Amount
	(In 000 s except unit data)		
Year ended December 31, 2008			
Basic EPS:			
Income allocable to unitholders	$ 7,268	22,350,638	$ 0.33
Effect of dilutive securities:			
Restricted common units Treasury stock method		19,353	
Diluted EPS:			
Income allocable to common unitholders	$ 7,268	22,369,991	$ 0.33

	Income	Unit	Per Unit Amount
	(In 000 s except unit data)		
Year ended December 31, 2007			
Basic EPS:			
Income allocable to unitholders	$ 14,241	16,321,547	$ 0.87
Effect of dilutive securities:			
Restricted common units Treasury stock method		3,961	
Diluted EPS:			
Income allocable to common unitholders	$ 14,241	16,325,508	$ 0.87

	Income	Unit	Per Unit Amount
	(In 000 s except unit data)		
Year ended December 31, 2006			
Basic EPS:			

Income allocable to unitholders	$ 15,989	11,320,300	$ 1.41
Effect of dilutive securities:			
Restricted common units Treasury stock method			
Diluted EPS:			
Income allocable to common unitholders	$ 15,989	11,320,300	$ 1.41

CEP s basic and diluted EPS are the same in each of the year ended December 31, 2006, as there were no dilutive common unit equivalents.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Comprehensive Income (Loss)

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

Class D Interests

Due to their contingently redeemable feature, the Class D interests are treated as preferred units subject to contingent redemption in accordance with SEC Accounting Series Release 268, *Presentation in Financial Statements of Redeemable Preferred Stocks*.

Environmental Cost

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

Unit-Based Compensation

The Company records compensation expense for all equity grants issued under the Long-Term Incentive Program based on the fair value at the grant date, recognized over the vesting period, according to SFAS 123 (R), *Stock-Based Payment*.

Other Contingencies

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

Accounting Standards Adopted Through February 20, 2009

In March 2008, the Emerging Issues Task Force reached a consensus on Issue 07-4, or EITF 07-4, Application of the Two-Class Method under FASB Statement 128, Earnings per Share, to Master Limited Partnerships. EITF 07-4 provides guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. This Issue is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted, and the guidance in this Issue is to be applied retrospectively for all financial statements presented. The adoption of this Issue did not have a material impact on our financial statements.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In March 2008, the FASB issued SFAS 161, *Disclosures About Derivative Instruments and Hedging Activities*. SFAS 161 is effective beginning January 1, 2009 and requires entities to provide expanded disclosures about derivative instruments and hedging activities including (1) the ways in which an entity uses derivatives, (2) the accounting for derivatives and hedging activities, and (3) the impact that derivatives have (or could have) on an entity s financial position, financial performance, and cash flows. SFAS 161 requires expanded disclosures and does not change the accounting for derivatives. CEP is currently evaluating the impact of SFAS 161, but we do not expect the adoption of this standard to have a material impact on our financial results.

In December 2007, the FASB issued SFAS 160, Noncontrolling Interests in Consolidated Financial Statements (SFAS 160). SFAS 160 amends Accounting Research Bulletin 51, Consolidated Financial Statements, and requires all entities to report noncontrolling (minority) interests in subsidiaries within equity in the consolidated financial statements, but separate from the parent shareholders equity. SFAS 160 also requires any acquisitions or dispositions of noncontrolling interests that do not result in a change of control to be accounted for as equity transactions. Further, SFAS 160 requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. SFAS 160 is effective for annual periods beginning on or after December 15, 2008. The adoption of SFAS 160 did not have a material impact on our financial statements.

In December 2007, the FASB issued SFAS 141 (revised 2007), Business Combinations (SFAS 141(R)). In SFAS 141(R), the FASB retained the fundamental requirements of Statement 141 to account for all business combinations using the acquisition method (formerly the purchase method) and for an acquiring entity to be identified in all business combinations. However, the new standard requires the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) is effective for annual periods beginning on or after December 15, 2008. The adoption of SFAS 141(R) did not have a material impact on our 2008 financial statements but will impact our future financial statements if we conduct a business combination.

In April 2007, the FASB issued Staff Position (FSP) FIN 39-1, *Amendment of FASB Interpretation 39.* FSP FIN 39-1 permits an entity to report all derivatives recorded at fair value with any associated fair value cash collateral, which are with the same counterparty under a master netting arrangement, together in the balance sheet. Under the provisions of this FSP, we must either report all derivatives recorded at fair value net with the associated fair value cash collateral or report all derivative amounts gross. The effects of FSP FIN 39-1 must be applied by adjusting all financial statements presented beginning January 1, 2008. FSP FIN 39-1 did not have a material impact on our financial statements.

In February 2007, the FASB issued SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, including an amendment to SFAS 115. Under SFAS 159, entities may elect to measure specified financial instruments and warranty and insurance contracts at fair value on a contract-by-contract basis, with changes in fair value recognized in earnings each reporting period. The election, called the fair value option, enables entities to achieve an offset accounting effect for changes in fair value of certain related assets and liabilities without having to apply complex hedge accounting provisions. SFAS 159 is expected to expand the use of fair value measurement consistent with the FASB s long-term objectives for financial instruments. SFAS 159 is effective as of the beginning of a company s first fiscal year that begins after November 15, 2007. We have assessed the provisions of SFAS 159 and we have elected not to apply fair value accounting to our existing eligible financial instruments. As a result, the adoption of SFAS 159 did not have an impact on our financial statements.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In September 2006, the FASB issued SFAS 157, *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures for fair value measurements. In February 2008, the FASB granted a one-year deferral of the effective date of this statement as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a non-recurring basis. The Statement codifies the definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The standard clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The standard defines the three levels of inputs as 1) observable inputs, 2) inputs other than quoted prices that are observable through corroboration, and 3) unobservable inputs. SFAS 157 is effective for all fair value measurements beginning January 1, 2008. As it relates to our financial assets and liabilities, SFAS 157 did not have a material impact on our financial statements.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2008, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us.

On December 31, 2008, the Securities and Exchange Commission (SEC) issued the final rule, Modernization of Oil and Gas Reporting (Final Rule). The Final Rule adopts revisions to the SEC s oil and gas reporting disclosure requirements and is effective for annual reports on Forms 10-K for years ending on or after December 31, 2009. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments are also designed to modernize the oil and gas disclosure requirements to align them with current practices and technological advances. Revised requirements in the Final Rule include, but are not limited to:

- Oil and gas reserves must be reported using a 12-month average of the closing prices on the first day of each of such months, rather than a single day year-end price;

- Companies will be allowed to report, on a voluntary basis, probable and possible reserves, previously prohibited by SEC rules; and

- Easing the standard for the inclusion of proved undeveloped reserves (PUDs) and requiring disclosure of information indicating any progress toward the development of PUDs.

We are currently evaluating the potential impact of adopting the Final Rule. The SEC is discussing the Final Rule with the FASB and IASB staffs to align accounting standards with the Final Rule. These discussions may delay the required compliance date. Absent any change in such date, we will begin complying with the disclosure requirements in our annual report on Form 10-K for the year ended December 31, 2009. Voluntary early compliance is not permitted.

2. ACQUISITIONS

Cola Acquisition

On March 31, 2008, the Company acquired 83 non-operated producing natural gas wells in the Woodford Shale in the Arkoma Basin in Oklahoma from CoLa Resources LLC (CoLa) for $50.2 million, including purchase price adjustments (CoLa Acquisition). CoLa is an affiliate of CEG, the Company s sponsor. The transaction was reviewed and approved by the Company s conflicts committee. In its review, the Company s conflicts committee considered various economic factors (including historical and estimated future production,

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

estimated proved reserves, future pricing estimates and operating cost estimates) regarding the transaction, and determined that the acquisition was fair and in the best interests of the Company. The 83 wells, located in Coal and Hughes Counties, Oklahoma, have an average gross working interest per well of 11.4% and an average net revenue interest per well of 9.2%. The acquired natural gas reserves associated with the wells are 100% proved developed producing. Our results of operations include the results of the CoLa wells after the date of acquisition.

To fund the purchase of CoLa, the Company borrowed $53.0 million under its reserve-based credit facilities (see Note 4).

Upon the announcement of the acquisition, the Company entered into derivative transactions to hedge a portion of the future expected production associated with these wells (see Note 3).

The total consideration paid was $50.2 million which consisted of $50.3 million in cash and transaction costs and assumed liabilities of approximately $0.1 million, primarily associated with asset retirement obligations on the properties. The following table summarizes the allocation of the purchase price to the assets acquired and liabilities assumed at the date of acquisition.

Acquired March 31, 2008		**(in millions)**
Oil and Natural Gas Properties	$	50.3
Total assets acquired		50.3
Asset retirement obligations		(0.1)
Net assets acquired	$	50.2

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

The purchase price allocation related to the CoLa acquisition remains subject to post-closing or title adjustments. Under the purchase agreement, the Company will have the right to assert, and CoLa will have the right to attempt to cure, any title defects to the acquired wells until July 31, 2009. CoLa s post-closing payment obligations with respect to title defects and indemnities under the purchase agreement is secured, in part, by a guaranty from CCG delivered at closing. The maximum amount of the CCG guaranty is limited to (i) 20% of the purchase price, with respect to indemnity obligations, and (ii) with respect to title defect obligations, the amount of such title defects, such amount to be calculated as provided in the purchase agreement. The amount of CCG s guaranty with respect to title defect obligations will decrease as title curative is received or CoLa receives proceeds of production from well bores as to which payments of production proceeds had not commenced as of the closing date and which are attributable to periods prior to the effective time of the purchase agreement. Under certain circumstances, identified title defects may result in a purchase price adjustment.

Newfield Acquisition

On September 21, 2007, the Company acquired certain oil and natural gas properties in the Cherokee Basin from Newfield Exploration Mid-Continent Inc. (Newfield). The acquisition included approximately 600 net producing wells on approximately 80,000 net acres as well as support equipment and facilities, including a pipeline gathering system. The results of operations include the results of Newfield since the date of acquisition.

In conjunction with the acquisition, the Company issued in a private placement 2,470,592 common units at an average price of $42.50 per unit for aggregate proceeds of approximately $105.0 million. Subsequent to this offering, the Company registered for resale all of these common units with the Securities and Exchange Commission. The proceeds from this equity placement, together with borrowings under the Company s existing credit facility, fully funded the purchase price of the acquisition.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Upon closing of the acquisition, the Company entered into derivative transactions to hedge a portion of the future expected production associated with these properties (see Note 3).

The total consideration paid was $127.1 million which consisted of $128.2 million in cash and assumed liabilities of $1.1 million, primarily associated with asset retirement obligations on the properties. The following table summarizes the allocation of the purchase price to the assets acquired and liabilities assumed at the date of acquisition.

Acquired September 21, 2007	**(in millions)**
Oil and Natural Gas Properties	$ 109.0
Unproved Properties	2.6
Pipelines	10.0
Other PP&E	1.0
Intangible Third Party Gas Contracts	5.0
Inventory	0.6
Total assets acquired	128.2
Asset retirement obligations	(1.1)
Net assets acquired	$ 127.1

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

Amvest Acquisition

On July 25, 2007, the Company acquired certain oil and natural gas properties in the Cherokee Basin through an Agreement of Merger with Amvest Osage, Inc. (Amvest). At the closing of the merger, Amvest became a wholly-owned subsidiary of the Company. The acquisition included a 13 year exclusive concession for coalbed methane and shale rights on approximately 560,000 net acres in Osage County, Oklahoma. Also included were producing wells, support equipment and facilities and certain pipeline gathering systems. The results of operations include the results of Amvest since the date of acquisition.

In conjunction with the acquisition, the Company issued in a private placement 2,664,998 common units and 3,371,219 newly-created Class F units at an average price of $34.79 per unit for aggregate proceeds of approximately $210.0 million. Subsequent to the offering, all of the Class F units were converted into common units. The Company has registered for resale all of the common units associated with the offering and the conversion of Class F units with the Securities and Exchange Commission. The proceeds from this equity placement, together with borrowings under the Company s existing credit facility, fully funded the purchase price of the acquisition.

Upon closing the transaction, the Company entered into derivative transactions to hedge a portion of the future expected production associated with this acquisition (see Note 3).

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The total consideration paid was $234.3 million which consisted of $232.8 million in cash, net working capital of $2.3 million, and assumed liabilities of $0.8 million, primarily associated with asset retirement obligations on the properties. An amount of $8.5 million which was placed in a drilling escrow fund was returned to the Company for use in drilling programs on proved undeveloped locations after the close of the transaction. The following table summarizes the allocation of the purchase price to the assets acquired and liabilities assumed at the date of acquisition.

Acquired July 25, 2007	**(in millions)**
Oil and Natural Gas Properties	$ 183.0
Unproved Properties	38.4
Pipelines	5.0
Other PP&E	1.4
Intangible Third Party Gas Contracts	5.0
Total assets acquired	232.8
Asset Retirement Obligation	(0.8)
Net Working Capital	2.3
Total	$ 234.3

The purchase price allocation is based on internal appraisals, evaluations of proved oil and natural gas reserves, discounted cash flows, quoted market prices, other estimates by management, and a valuation report.

EnergyQuest Acquisition

On April 23, 2007, the Company completed the acquisition of certain coalbed methane properties in the Cherokee Basin of Oklahoma and Kansas and interests in certain limited liability companies which own coalbed methane properties in the Cherokee Basin (the EnergyQuest Assets). In conjunction with the acquisition, the Company issued in a private placement 2,207,684 common units at a price of $26.12 per unit and 90,376 newly-created Class E units at a price of $25.84 per unit for aggregate proceeds of approximately $60.0 million. Subsequent to the offering, all of the Class E units were converted into common units. The Company has registered for resale all of the common units associated with the offering and the conversion of the Class E units with the Securities and Exchange Commission. The proceeds from this equity placement, together with borrowings under the Company s existing credit facility, fully funded the purchase price of the acquisition. The results of operations include the results of EnergyQuest since the date of acquisition.

Upon closing of the acquisition, the Company entered into derivative transactions to hedge a portion of the future expected production associated with this acquisition (see Note 3).

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The total consideration paid for EnergyQuest was $115.8 million which consisted of $117.0 million in cash and assumed liabilities of $1.2 million, primarily associated with asset retirement obligations on the properties. The Company also assumed an estimated asset retirement obligation of $1.1 million and other miscellaneous liabilities of $0.1 million. The following table summarizes the allocation of the purchase price to the assets acquired and liabilities assumed at the date of acquisition.

Acquired April 23, 2007	**(in millions)**
Oil and Natural Gas Properties	$ 105.1
Pipelines	5.7
Investment in Unconsolidated Affiliates	4.0
Unproved Properties	1.6
Other Property, Plant and Equipment	0.5
Land	0.1
Total assets acquired	117.0
Asset retirement obligations	(1.1)
Other liabilities	(0.1)
Net assets acquired	$ 115.8

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

Pro Forma Results

The unaudited pro forma results presented below have been prepared to give effect to the EnergyQuest, Amvest, Newfield, and CoLa acquisitions described above on our results of operations as if they had been consummated at the beginning of the period presented. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if these acquisitions had been completed on such date or to project our results of operations for any future date or period.

	December 31, 2008	**December 31, 2007 (In 000 s)**	**December 31, 2006**
Pro forma:			
Revenue	$ 166,573	$ 122,061	$ 116,763
Net income	$ 7,268	$ 14,381	$ 20,169
Basic earnings per share	$ 0.33	$ 0.64	$ 0.90
Diluted earnings per share	$ 0.33	$ 0.64	$ 0.90

3. DERIVATIVE AND FINANCIAL INSTRUMENTS

Hedging Activities

The Company has hedged a portion of its expected natural gas sales from currently producing wells through December 2013. The value of the cash flow hedges for natural gas included in Accumulated other comprehensive income (loss) on the Consolidated Balance Sheets was an unrecognized gain of approximately $57.8 million and an unrecognized gain of $6.9 million at December 31, 2008 and December 31, 2007, respectively. The Company expects that $32.0 million of the unrecognized gain will be reclassified from Accumulated other comprehensive income (loss) to the income statement in the next twelve months. There was approximately $1.2 million of gains as a result of hedge ineffectiveness for the twelve months ended December 31, 2008, and losses of approximately $1.2 million for the twelve months ended December 31, 2007.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2008 and 2007, the Company had debt outstanding of $212.5 million and $153.0 million, respectively, under its reserve-based credit facilities. The Company has entered into hedging arrangements in the form of interest rate swaps to reduce the impact of volatility stemming from changes in the London interbank offered rate (LIBOR) on $168.0 million of the outstanding debt through October 2010. The interest rate swaps have termination dates between February 20, 2010 and October 19, 2010. The swaps have been designated as cash flow hedges of the risk associated with changes in the designated benchmark LIBOR interest rate related to forecasted payments associated with interest on the reserve-based credit facilities. The Company assesses and records ineffectiveness for the interest rate swaps in accordance with the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. There was no hedge ineffectiveness identified related to the interest rate swaps. The value of the Company s cash flow hedges for interest rates included in Accumulated other comprehensive income (loss) was an unrecognized loss of approximately $7.7 million at December 31, 2008 and an unrecognized loss of $2.7 million at December 31, 2007.

Mark-to-Market Activities

The Company has certain swaps, basis swaps, and options that are accounted for as mark-to-market activities.

For the twelve months ended December 31, 2008 and 2007, the Company recognized mark-to-market gains of approximately $21.4 million and losses of approximately $6.9 million, respectively, in connection with these positions. At December 31, 2008 and December 31, 2007, the fair value of the derivatives accounted for as mark-to-market activities amounted to a net asset of approximately $20.9 million and a net asset of approximately $2.2 million, respectively.

SFAS 157

Effective January 1, 2008, we adopted SFAS 157, *Fair Value Measurements* for financial assets and liabilities measured on a recurring basis. SFAS 157 defines fair value, establishes a framework for measuring fair value and requires certain disclosures about fair value measurements for assets and liabilities measured on a recurring basis. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS 157 by one year for non-financial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We have elected to utilize this deferral and have only partially applied SFAS 157 (to financial assets and liabilities measured at fair value on a recurring basis, as described above). Accordingly, we will apply SFAS 157 to our nonfinancial assets and liabilities for which we disclose or recognize at fair value on a nonrecurring basis, such as asset retirement obligations and other assets and liabilities in the first quarter of 2009. Fair value is the exit price that we would receive to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date.

SFAS 157 also establishes a hierarchy that prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices available in active markets for identical assets or liabilities as of the reporting date.

Level 2 Pricing inputs other than quoted prices in active markets included in Level 1 which are either directly or indirectly observable as of the reporting date. Level 2 consists primarily of non-exchange traded commodity derivatives.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Certain of our derivatives are classified as Level 3 because observable market data is not available for all of the time periods for which we have derivative instruments. As observable market data becomes available for all of the time periods, these derivative positions will be reclassified as Level 2. The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2 or Level 3. We prioritize the use of the highest level inputs available in determining fair value.

The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. Because of the long-term nature of certain assets and liabilities measured at fair value as well as differences in the availability of market prices and market liquidity over their terms, inputs for some assets and liabilities may fall into any one of the three levels in the fair value hierarchy. While SFAS 157 requires us to classify these assets and liabilities in the lowest level in the hierarchy for which inputs are significant to the fair value measurement, a portion of that measurement may be determined using inputs from a higher level in the hierarchy.

The following table sets forth by level within the fair value hierarchy the Company s assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2008.

At December 31, 2008	Level 1	Level 2	Level 3	Netting and Cash Collateral*	Total Net Fair Value
			(In thousands)		
Risk management assets	$	$ 55,581	$ 6,752	$	$ 65,333
Risk management liabilities	$	$	$	$	$
Total	$	$ 55,581	$ 6,752	$	$ 65,333

* *All of our derivative instruments are secured by our reserve-based credit facilities.*

Risk management assets and liabilities in the table above represent the current fair value of all open derivative positions, including swaps, options, swaption, and basis swaps. We classify all of our derivative instruments as Risk management assets or Risk management liabilities in our Consolidated Balance Sheets.

The valuation of our derivatives is performed by Constellation under a management services agreement (see Note 7). In order to determine the fair value amounts presented above, Constellation utilizes various factors, including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and parental guarantees), but also the impact of our nonperformance risk on our liabilities. We use our reserve-based credit facilities, or guarantees from Constellation, to provide credit support for our derivative transactions. As a result, we do not post cash collateral with our counterparties, nor make any adjustments for non-performance credit risk on our liabilities with counterparties. We utilize observable market data for credit default swaps to assess the impact of non-performance credit risk when evaluating our assets from counterparties. At December 31, 2008, the impact of non-performance credit risk on the valuation of our assets from counterparties was $0.9 million, of which $0.4 million was reflected as a reduction to our non-cash market-to-market gain and $0.5 million was reflected as a reduction to our accumulated other comprehensive income.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In certain instances, Constellation may utilize internal models to measure the fair value of our derivative instruments. Generally, Constellation uses similar models to value similar instruments. Valuation models utilize various inputs which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the assets or liabilities, and market-corroborated inputs, which are inputs derived principally from or corroborated by observable market data by correlation or other means.

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

	Twelve Months Ended December 31, 2008 (In thousands)
Balance at beginning of period	$ (3,591)
Realized and unrealized gains:	
Included in earnings	10,502
Included in other comprehensive income	18,127
Purchases, sales, issuances, and settlements	(7,395)
Transfers into and out of Level 3(a)	(10,891)
Balance as of December 31, 2008	$ 6,752
Change in unrealized gains relating to derivatives still held as of December 31, 2008	$ 21,924

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

Credit Support Fee Agreements

In connection with certain of our acquisitions, Constellation entered into credit support agreements with us to provide guarantees to three banks that required credit support for certain financial derivatives. These guarantees were obtained because we did not own the assets at the time the derivatives were entered into and we could not use our existing reserve-based credit facility to provide collateral for the derivative transactions.

In February 2008, in connection with the CoLa Acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $8.5 million for certain financial derivatives that we entered into with BNP Paribas (BNP) and Societe Generale (SocGen). These guarantees have been released.

In August 2007, in connection with the Newfield acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $10.0 million for certain financial derivatives that we entered into with BNP. This guarantee has been released.

In July 2007, in connection with the Amvest acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $15.0 million for certain financial derivatives that we entered into with BNP.

This guarantee has been released.

In March 2007, in connection with the EnergyQuest acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $11.5 million for certain financial derivatives that we entered into with BNP. This guarantee has been released.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In March 2007, in connection with the EnergyQuest acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $25 million for certain financial derivatives that we entered into with The Royal Bank of Scotland plc (RBS). This guarantee has been released.

Through December 31, 2008, Constellation charged us $0.8 million for this credit support.

Fair Value of Financial Instruments

At December 31, 2008, the carrying values of cash and cash equivalents, accounts receivable, other current assets, and current liabilities on the Consolidated Balance Sheets approximate fair value because of their short term nature. The Company believes the carrying value of long-term debt approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms, which represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties.

4. DEBT

Reserve-Based Credit Facility

On March 28, 2008, the Company entered into a new credit agreement and an amended and restated credit agreement, each as discussed below. The two agreements contain similar commercial terms with the same lenders participating in the same applicable percentages. A cross-default feature provides that an event of default under one agreement constitutes an event of default under the other. Each credit agreement is secured by distinct mortgages of properties as well as guarantees by the Company s subsidiaries.

The current lenders and their percentage commitments in each of the Company s two credit facilities are: The Royal Bank of Scotland (23.32%), BNP Paribas (22.55%), Wachovia Bank, N.A. (14.55%), Bank of Nova Scotia (17.00%), Calyon New York Branch (15.05%), and Societe Generale (7.53%).

New Credit Agreement

On March 28, 2008, the Company entered into a new $500.0 million secured credit agreement (Credit Facility) with The Royal Bank of Scotland plc as administrative agent (the Administrative Agent) and a syndicate of lenders. The amount available for borrowing at any one time is limited to the borrowing base for the Company s properties other than in the State of Alabama, which was initially set at $150.0 million. In July 2008, the Company expanded its borrowing base under the $500.0 million Credit Facility from $150.0 million to $175.0 million. The borrowing base will be re-determined semi-annually by the lenders in their sole discretion based on reserve reports as prepared by reserve engineers, together with, among other things, the oil and natural gas prices at such time. Any increase in each borrowing base must be approved by all of the lenders. Under certain conditions, the Credit Facility may be increased up to an additional $225.0 million. The Credit Facility matures on October 31, 2010.

Borrowings under the Credit Facility are available for acquisition, exploration, operation and maintenance of oil and natural gas properties located in states other than Alabama, payment of expenses incurred in connection with the credit facilities, working capital and general limited liability company purposes. The Credit Facility has a sub-limit of $20.0 million which may be used for the issuance of letters of credit.

At the Company s election, interest for borrowings under the Credit Facility is determined by reference to (i) the London interbank rate, or LIBOR, plus an applicable margin between 1.25% and 2.00% per annum based on utilization or (ii) a domestic bank rate plus an applicable margin between 0.25% and 1.00% per annum based on utilization. Interest on borrowings under the Credit Facility is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Credit Facility contains various covenants that limit, among other things, the Company s, and certain of the Company s subsidiaries , ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of the Company s assets, make certain loans, acquisitions, capital expenditures and investments, and make distributions other than from available cash.

In addition, the Company is required to maintain (i) a ratio of debt to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus 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 or sale of assets, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on natural gas derivatives and realized (gain) loss on cancelled natural gas derivatives, and other similar charges) of not more than 3.50 to 1.00; (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, of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143, *Accounting for Asset Retirement Obligations* (including the current liabilities in respect of the termination of natural gas and interest rate swaps). All financial covenants are calculated using CEP s consolidated financial information.

The 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 Credit Facility and a change of control. If an event of default occurs under the Credit Facility, the lenders will be able to accelerate the maturity of the Credit Facility and exercise other rights and remedies.

The Credit Facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, amount 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 the Company and its subsidiaries who are guarantors taken as a whole. If a MAE were to occur, CEP would be prohibited from borrowing under the reserve-based credit facilities and would be in default under the facilities, which could cause all of its existing indebtedness to become immediately due and payable.

Borrowings under the Credit Facility are secured by various mortgages of properties that the Company owns in states other than Alabama as well as a security and pledge agreement among the Company and certain of its subsidiaries and the Administrative Agent.

We have the ability to borrow under the Credit Facility to pay distributions to unitholders as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding under the credit facilities exceeds 90% of the borrowing base.

On March 28, 2008, the Company borrowed $131.0 million under the term loan portion of the Credit Facility. A portion of the proceeds of the borrowings (less associated transaction costs) were used to finance the aggregate consideration for the acquisition of CoLa, and a portion of the proceeds of the borrowings (less associated transaction costs) were used to repay existing indebtedness. Through the December 31, 2008, the Company borrowed a net $0.5 million, increasing the total borrowings under the credit facility to $131.5 million.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Amended and Restated Credit Agreement

On March 28, 2008, the Company amended and restated its existing $200.0 million credit facility by entering into an amended and restated credit agreement with the Administrative Agent and a syndicate of lenders (the Amended and Restated Credit Facility). The amount available for borrowing at any one time is limited to the borrowing base for the Company s properties in the State of Alabama, which was initially set at $90.0 million. The borrowing base will be re-determined semi-annually by the lenders in their sole discretion based on reserve reports as prepared by reserve engineers, together with, among other things, the oil and natural gas prices at such time. Any increase in each borrowing base must be approved by all of the lenders. The Amended and Restated Credit Facility matures on October 31, 2010.

Borrowings under the Amended and Restated Credit Facility are available for acquisition, exploration and the operation and maintenance of oil and natural gas properties located in the State of Alabama, payment of expenses incurred in connection with the credit facilities, working capital and general limited liability company purposes. The Amended and Restated Credit Facility has a sub-limit of $20.0 million which may be used for the issuance of letters of credit.

At the Company s election, interest for borrowings under the Amended and Restated Credit Facility is determined by reference to (i) the London interbank rate, or LIBOR, plus an applicable margin between 1.25% and 2.00% per annum based on utilization or (ii) a domestic bank rate plus an applicable margin between 0.25% and 1.00% per annum based on utilization. Interest on borrowings under the Amended and Restated Credit Facility is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

The Amended and Restated Credit Facility contains various covenants that limit, among other things, the Company s, and certain of the Company s subsidiaries , ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of the Company s assets, make certain loans, acquisitions, capital expenditures and investments, and make distributions other than from available cash.

In addition, the Company is required to maintain (i) a ratio of debt to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus 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 or sale of assets, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on natural gas derivatives and realized (gain) loss on cancelled natural gas derivatives, and other similar charges) of not more than 3.50 to 1.00; (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, of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143, *Accounting for Asset Retirement Obligations* (including the current liabilities in respect of the termination of natural gas and interest rate swaps). All financial covenants are calculated using CEP s consolidated financial information.

The Amended and Restated 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 Amended and Restated Credit Facility and a change of control. If an event of default occurs under the Amended and Restated Credit Facility, the lenders will be able to accelerate the maturity of the Amended and Restated Credit Facility and exercise other rights and remedies.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Credit Facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, amount 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 the Company and its subsidiaries who are guarantors taken as a whole. If a MAE were to occur, CEP would be prohibited from borrowing under the reserve-based credit facilities and would be in default under the facilities, which could cause all of its existing indebtedness to become immediately due and payable.

Borrowings under the Amended and Restated Credit Facility are secured by various mortgages of properties the Company owns in Alabama as well as a security and pledge agreement among the Company and certain of its subsidiaries and the Administrative Agent.

We have the ability to borrow under the Amended and Restated Credit Facility to pay distributions to unitholders as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding under the credit facilities exceeds 90% of the borrowing base.

On March 28, 2008, the Company borrowed $81.0 million under the term loan portion of the Amended and Restated Credit Agreement, the proceeds of which (less associated transaction costs) were used to repay existing indebtedness.

Total debt issue costs incurred through December 31, 2008, were approximately $3.4 million. These costs are being amortized over the life of the credit facilities. As of December 31, 2008 and 2007, the Company had $212.5 million and $153.0 million, respectively, in outstanding debt under its reserve-based credit facilities. As of December 31, 2008, the Company had $52.5 million in remaining borrowing capacity under the reserve-based credit facilities, of which $26.0 million is available for borrowing.

As of December 31, 2007 and 2006, CEP had $153.0 million and $22.0 million, respectively, in outstanding debt under the reserve-based credit facility. As of December 31, 2007, the Company had $27.0 million in borrowing capacity under the reserve-based credit facility.

Compliance with Debt Covenants

Our reserve-based credit facilities mature in October 2010 and, as a result, amounts due under the facilities are scheduled to become a current liability in October 2009. We may not be able to renew or replace the facilities at similar borrowing costs, terms, covenants, restrictions, or borrowing base, or with similar debt issue costs.

The reserve-based credit facilities limit the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. The 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, together with, among other things, the oil and natural gas prices existing at the time. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the reserve-based credit facilities. Outstanding borrowings in excess of the borrowing base must be repaid immediately, 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 facilities.

At December 31, 2008, CEP believes that it was in compliance with the debt covenants contained in its credit facilities. CEP monitors compliance on an ongoing basis. As of December 31, 2008, the actual debt to Adjusted EBITDA ratio was 2.8 to 1.0 as compared with a required ratio of not greater than 3.5 to 1.0, the actual

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ratio of current assets to current liabilities was 3.5 to 1.0 as compared with a required ratio of not less than 1.0 to 1.0, and the actual Adjusted EBITDA to cash interest expense ratio was 7.2 to 1.0 as compared with a required ratio of not less than 2.5 to 1.0.

If CEP is unable to remain in compliance with the debt covenants associated with its reserve-based credit facilities or maintain the required ratios discussed above, CEP could request waivers from the lenders in its bank group. Although the lenders may not provide a waiver, CEP may take additional steps in the event of not meeting the required ratios or in the event of a reduction in the combined borrowing base below its current level of $265.0 million at one of the future redeterminations by the lenders. If it becomes necessary to pay debt down beyond operating cash flows, CEP could reduce capital expenditures, further reduce or eliminate quarterly distributions to unitholders, sell oil and natural gas properties, liquidate in the money derivative positions, further reduce operating and administrative costs, or take additional steps to increase liquidity. To the extent that CEP does not enter into an agreement to refinance or extend the due date on the reserve-based credit facilities, the outstanding debt balance at October 31, 2009, will become a current liability.

5. OIL AND NATURAL GAS PROPERTIES

Natural gas properties consist of the following:

	December 31, 2008	December 31, 2007 (In 000 s)	December 31, 2006
Oil and natural gas properties and related equipment (successful efforts method)			
Property (acreage) costs			
Proved property	$ 729,898	$ 635,224	$ 181,747
Unproved property	38,293	39,018	88
Total property costs	768,191	674,242	181,835
Materials and supplies	4,587	2,880	1,264
Land	912	902	160
Total	773,690	678,024	183,259
Less: Accumulated depreciation, depletion and amortization	(111,171)	(34,371)	(11,620)
Natural gas properties and equipment, net	$ 662,519	$ 643,653	$ 171,639

Impairment of Oil and Natural Gas Properties

In 2008, CEP recorded a charge of $25.7 million to impair the value of its 83 well bores located in the Woodford Shale in Oklahoma. This charge is included in depreciation, depletion and amortization in the Statement of Operations. This impairment was recorded because the carrying value of the asset exceeded the fair value of the asset as measured by estimated cash flows reported in a third party reserve report that was based upon future expected oil and natural gas prices. The impairment is primarily caused by the impact of lower production volumes than originally estimated, a higher initial production decline rate, and lower future expected natural gas prices. Cash flow estimates for the impairment testing exclude derivative instruments. As of December 31, 2008, CEP reviewed its other properties for impairment and the estimated undiscounted future cash flows exceeded the net capitalized costs, thus no impairment was required to be recognized. As of December 31, 2007 and 2006, the estimated undiscounted future cash flows for CEP s proved oil and natural gas properties exceeded the net capitalized costs, thus no impairment was required to be recognized.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Asset Sales

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

In 2007, CEP sold a surplus compressor for $0.2 million and recorded a $0.1 million loss on the sale.

Involuntary Conversion

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

Useful Lives

CEP s furniture, fixtures, and equipment are depreciated over a life of one to five years, buildings are depreciated over a life of twenty years, and pipeline and gathering systems are depreciated over a life of twenty-five to forty years.

6. BENEFIT PLANS

Eligible employees of CEP participate in employment savings plans. Contributions by CEP were approximately $0.1 million and $0.05 million for the years ended December 31, 2008, and 2007, respectively. Prior to our IPO in November 2006, Constellation Energy Group, Inc. contributed approximately $0.02 million.

7. RELATED PARTY TRANSACTIONS

Management Services Agreement

In November 2006, CEP entered into a management services agreement with Constellation Energy Partners Management, LLC (CEPM), a subsidiary of Constellation, to provide certain management, technical and administrative services. These services include legal, accounting and finance, engineering and technical, risk management, information technology and tax services, as well as acquisition services related to opportunities to acquire oil and natural gas reserves and related midstream assets. CEPM and its affiliates do not have any obligation to provide acquisition services or other services under the management services agreement, provided that CEPM may receive added compensation for providing CEP with services as a result of the management incentive interests it holds in CEP. Each quarter, CEPM charges CEP an amount for services provided to CEP. This amount is agreed to annually and includes a portion of the compensation paid by CEPM and its affiliates to personnel who spend time on CEP s business and affairs. The allocation of compensation expense for the chief executive officer, chief financial officer and chief accounting officer is fixed by agreement between the parties for 2008 and 2007. The allocation of compensation expense for other personnel of CEPM and its affiliates is determined based on the percentage of time spent by such personnel on CEP s business and affairs. The conflicts committee of the Company s board of managers reviews at least annually the services to be provided by CEPM and the costs to be charged to CEP under the management services agreement and reviews the cost allocation quarterly. The conflicts committee also determines if the amounts to be paid by the Company for the services to be performed are fair to and in the best interests of the Company. During the year, the cost allocation may be adjusted upwards to reflect additional services provided by CEPM and its affiliates or downwards to reflect the transition of services to CEP employees. These costs totaled approximately $2.9 million and $1.4 million for the year ended December 31, 2008 and 2007, respectively. The costs charged to CEP under the management services

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

agreement may be greater or less than the actual costs CEP would incur if the services were performed by an unaffiliated third party.

CEP had a payable to CEPM of $0.8 million and $0.4 million and to CCG of $0.3 million and $2.4 million as of December 31, 2008 and 2007, respectively. This payable balance is included in current liabilities in the accompanying balance sheets.

Credit Support Fee Agreements

As described further in Note 3, CEG and CEP entered into credit support fee agreement under which CEG guaranteed credit support for certain financial derivatives with three financial institutions. These credit support fee agreement have expired. For the years ended December 31, 2008, and December 31, 2007, CEG charged CEP $0.2 million and $0.6 million for the credit support, respectively.

Natural Gas Purchases

In 2007, CCG began purchasing natural gas from CEP in the Cherokee Basin. The arrangement was reviewed by the conflicts committee of CEP s board of managers. The committee found that the arrangement was fair to and in the best interests of CEP. Through July 31, 2009, CEP has a guarantee from Constellation for payment of up to $8 million for sales made to CCG. In addition, CCG provided CEP a letter of credit to secure the payment for natural gas purchases currently for $2.5 million through Wachovia Bank, which expires on April 15, 2009. For the twelve months ended December 31, 2008, CCG has paid CEP $24.1 million for natural gas purchases. During 2007, the marketing arrangement for the CCG purchases was administered by Newfield under a transition services agreement.

Management Incentive Interests

CEPM holds the management incentive interests in the Company. 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 the Company s limited liability company agreement) has been achieved and certain other tests have been met. For the twelve months ended December 31, 2008, none of these applicable tests have been met, and, as a result, CEPM was not entitled to receive any management incentive interest distributions. For the third quarter 2007, the Company increased its distribution rate to $0.5625 per unit. This increase in the distribution rate commenced a management incentive interest vesting period under the Company s operating agreement. A cash reserve of $0.7 million has been established to fund future distributions on the management incentive interests. See Note 17 for additional information.

CoLa Acquisition

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

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Equity Contributions

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

During the year ended December 31, 2006, CCG paid $0.6 million of additional expenses on CEP s behalf in exchange for additional equity in CEP. These expenses included legal fees, fees for consultants hired by CEP and various other expenses.

Cash Pool Arrangement

In February 2006, CEP entered into a cash pool arrangement with CCG. This cash pool arrangement was administered and managed by CEP. CCG could borrow from the pool at market interest rates. If CEP required cash and CCG had an outstanding balance, CCG was required to immediately remit payment to CEP for the required cash amount. Upon the completion of its initial public offering, CEP ceased its participation in the cash pool arrangement and CCG retained the $12.4 million receivable balance. This was treated as a reduction of members equity for accounting purposes.

Prior to the initial public offering, due to the affiliate relationship described above, the financial position, results of operations and cash flows of CEP may differ from those that would have been achieved had CEP operated autonomously or as an entity independent of the ultimate parent and its subsidiaries.

Sale of Floyd Shale Rights

On October 30, 2006, CEP received $475,000 from an affiliate of Constellation Energy Group for the sale of the Floyd Shale Rights. These rights are an undivided mineral interest in our properties in the Black Warrior Basin for depths generally below 100 feet below the base of the lowest producing coal seam.

8. COMMITMENTS AND CONTINGENCIES

In the course of its normal business affairs, the Company is subject to possible loss contingencies arising from federal, state and local environmental, health and safety laws and regulations and third-party litigation. As of December 31, 2008 and 2007, other than the matters discussed below, there were no matters which, in the opinion of management, would have a material adverse effect on the financial position, results of operations or cash flows of CEP.

The Robinson s Bend Field is subject to a net profits interest (NPI) held by Torch Energy Royalty Trust (the Trust) (See Note 10). The royalty payment to the Trust is calculated using a sharing arrangement with a pricing formula that has had the effect of keeping our payments to the Trust lower than if such payments had been calculated based on prevailing market prices. CEP is uncertain of the financial impact of the NPI over the life of the Robinson s Bend Field as it has volumetric and price risk variables. However, in order to address a portion of the risk of the potential adverse impact on CEP s operating results from a termination of the sharing arrangement, Constellation Holdings, Inc. (CHI) contributed $8.0 million to CEP in exchange for all of CEP s Class D interests at the closing of its initial public offering to be used to protect the distributions to the common unit holders in the event the sharing arrangement is terminated. This contribution will be returned to CHI in 24 special quarterly distributions as long as the sharing agreement remains in effect for the distribution period. As a

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

result of the initiation of the legal proceedings discussed in Note 10 and Note 17, the Class D interest special quarterly distributions were suspended beginning with the special quarterly cash distributions for the three months ending December 31, 2008, September 30, 2008, June 30, 2008, and March 31, 2008. See Note 17 for additional information.

For CEP s 2009 drilling programs, CEP has committed to purchase approximately $2.2 million in pipe, tubing, and casing.

Other

On June 7, 2006, CCG and a subsidiary of CEP entered into an agreement with The Investment Company LLC (TIC) pursuant to which CCG agreed to pay TIC $3.1 million for consulting services associated with the acquisition of the Properties upon CEP s completion of its initial public offering on or before January 31, 2007. The fair value of this option also approximated $3.1 million. Accordingly, $3.1 million, was recorded in accrued liabilities as of December 31, 2005 as resolution of this matter related to a claim for prior service that was finalized prior to the issuance of the consolidated financial statements for those periods. The corresponding charge is reflected as General and administrative expense in the CEP Statement of Operations for the period ending December 31, 2005. At the completion of CEP s initial public offering in November 2006, the $3.1 million was paid to TIC.

9. ASSET RETIREMENT OBLIGATION

CEP follows SFAS 143, *Accounting for Asset Retirement Obligations.* SFAS 143 requires that the fair value of a liability for an asset retirement obligation (ARO) be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost (ARC) is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the ARC is allocated to expense using a systematic and rational method over the asset s useful life. The ARO s recorded by CEP relate to the plugging and abandonment of natural gas wells, and decommissioning of the gas gathering and processing facilities.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions result in adjustments to the recorded fair value of the existing ARO, a corresponding adjustment is made to the ARC capitalized as part of the gas property balance.

The following table is a reconciliation of the ARO:

	December 31, 2008	December 31, 2007	December 31, 2006
		(In 000 s)	
Asset retirement obligation, beginning balance	$ 6,163	$ 2,730	$ 2,524
Liabilities incurred from acquisition of the properties (Note 2)	56	3,056	
Liabilities incurred	124	65	65
Accretion expense	411	312	141
Asset retirement obligation, ending balance	$ 6,754	$ 6,163	$ 2,730

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2008, 2007, and 2006, there were no material expenditures for abandonments.

At December 31, 2008, 2007, and 2006 there were no assets legally restricted for purposes of settling existing asset retirement obligations.

10. NET PROFITS INTEREST

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

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

The Net Proceeds equal the lesser of (i) 95% of the net proceeds from 393 producing wells in the Robinson s Bend Field and (ii) the net proceeds from the sale of 912.5 MMcf of natural gas for the quarter. Net proceeds equal gross proceeds, currently calculated by reference to the gas purchase contract (for a description of the gas purchase contract, please read Item 1. Business Natural Gas Data Torch Royalty NPI The Gas Purchase Contract in the Company s Annual Report on Form 10-K for the year ended December 31, 2008), less specified costs attributable to the Robinson s Bend Assets. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (i) of the first sentence of this paragraph (the NPI Net Proceeds Calculation) include: (a) delay rentals, shut-in royalties and similar payments, (b) property, production, severance and similar taxes and related audit charges, (c) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies, (d) certain liabilities for environmental damage, personal injury and property damage, (e) certain litigation costs, (f) costs of environmental compliance, (g) specified operating costs incurred to produce hydrocarbons, (h) specified development costs (including costs to increase recoverable reserves or the timing of recovery of such reserves), (i) costs of specified lease renewals and extensions and unitization costs and (j) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (ii) of the first sentence of this paragraph include: (a) property, production, severance and similar taxes, (b) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies and (c) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. Net proceeds are calculated quarterly and any negative balance (expenses in excess of revenues) within the net proceeds calculation accumulates and is charged interest as described above.

The cumulative Net NPI Proceeds balance must be greater than $0 before any payments are made to the Trust. The cumulative Net Proceeds was a deficit for the three months ended December 31, 2008 and 2007. As a result, no payments were made to the Trust with respect to the NPI for the twelve months ended December 31, 2008 and 2007.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The calculation of the Infill Net Proceeds uses the same methodology as the NPI Net Proceeds Calculation described above except that the proceeds and costs are attributable not to the NPI Net Proceeds Wells, but to the remaining wells in the Robinson s Bend Field that are subject to the NPI and that have been drilled since the Trust was formed and wells that will be drilled (other than wells drilled to replace damaged or destroyed wells), in each case on leases subject to the NPI. The NPI in the Infill Wells entitles the Trust to receive 20% of the Infill Net Proceeds. There has never been a payout on the Infill Net Proceeds.

Termination of the Trust and Gas Purchase Contract

On January 29, 2008, the unitholders of the Torch Energy Royalty Trust voted to terminate the Trust and the trust agreement and authorized the Trustee to wind up, liquidate, and distribute the assets held by the Trust under the terms of the trust agreement. The gas purchase contract, by its terms, was also terminated on January 29, 2008 as a result of the termination of the Trust.

With the gas purchase contract terminated, we are no longer obligated to sell gas produced from our interest in the Black Warrior Basin pursuant to the gas purchase contract. Notwithstanding the termination of the gas purchase contract, the NPI will continue to burden the Trust Wells, and it should continue to be calculated as if the gas purchase contract were still in effect, regardless of what proceeds may actually be received by us as the seller of the gas. Originally, the Trust indicated that it believed that the net profits interest would continue to be calculated as if the gas purchase contract was still in effect. The Trust, however, subsequently indicated that the documents creating the NPI were not clear as to this point. As a result, on January 25, 2008, Torch Royalty Company (Torch Royalty), Torch E&P Company (Torch E&P) and CEP (collectively, the Claimants) sent notice of a demand for arbitration before Judicial Arbitration and Mediation Services (JAMS) to Wilmington Trust Company, as Trustee (Trustee) for the Trust, and to Capital One, NA, as successor to Hibernia National Bank, as trustee for Torch Energy Louisiana Royalty Trust, pursuant to the operative dispute resolution provisions of the agreement governing the Trust, the NPI and the Conveyances (as defined below). The Claimants were working interest owners in certain oil and gas fields located in Texas, Louisiana and Alabama. The working interests owned by the other Claimants are similarly subject to net profit interests (the Other NPIs) that are also based on the gas purchase contract. In the arbitration demand, we and the other Claimants sought a declaratory judgment that the NPI payments as well as the payments owed in respect of the Other NPIs will continue to be calculated using the sharing arrangement under the gas purchase contract even though the Trust and the gas purchase contract have been terminated. In its response to the Claimant s arbitration demand, the Trustee took the position that the sharing arrangement under the gas purchase contract terminated upon the termination of that contract. On July 18, 2008, the arbitration panel issued its final award (the Final Award) which, among other things, found and concluded that the sharing arrangement and other pricing terms of the gas purchase contract will continue to control the amount owed to the holder of the NPI.

The Trust and Trust Venture filed a petition to vacate the Final Award (the Petition to Vacate) with the District Court of Harris County, Texas, 152nd Judicial District (the District Court) on October 16, 2008. The Claimants filed a motion to confirm the Final Award (the Motion to Confirm) with the District Court on November 5, 2008. On December 10, 2008, the District Court dismissed the Petition to Vacate and granted the Motion to Confirm, thus confirming the Final Award. The Company believes that any timely further appeal or request for other relief by the Trust and Trust Venture should have been filed by January 9, 2009. The Company is not aware of any filing having been made as of December 31, 2008. See Note 17 for additional information.

Water Gathering, Separation, and Disposal Costs

As a result of the termination of the Trust, certain water gathering, separation and disposal costs, which are a component of the NPI calculation, increased from $0.53 per barrel to $1.00 per barrel pursuant to the Water

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gathering and Disposal Agreement dated August 9, 1990, as amended, attached as exhibits to this annual report. The amounts of the water gathering, separation and disposal costs are set forth in the Water Gathering and Disposal Agreement, as amended. See Note 17 for additional information.

11. ENVIRONMENTAL LIABILITY

CEP is subject to costs resulting from federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. As of December 31, 2008 and 2007, accrued environmental obligations were $0.4 million and $0.5 million, respectively. These obligations were classified as current liabilities on CEP s Consolidated Balance Sheet.

12. UNIT-BASED COMPENSATION

The Company recognized approximately $0.3 million of expense related to its long-term incentive plan s unit-based compensation in the twelve months ended December 31, 2008.

2008 Grants

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

The Company granted 11,004 restricted common unit awards on March 1, 2008, to the independent, non-employee members of the Board of Managers. These units had a total fair market value of approximately $225,000 at the grant date. These service-based restricted units will vest in full on March 1, 2009.

2007 Grants

The Company granted 5,343 restricted common unit awards on September 14, 2007, to the independent, non-employee members of the Board of Managers. These units had a total fair market value of approximately $225,000 at the grant date. This amount was recognized over the vesting period. These restricted common units vested in full on March 1, 2008.

13. DISTRIBUTIONS TO UNITHOLDERS

Distributions through December 31, 2008

On October 24, 2008, the Company declared a distribution for the third quarter of 2008 at a rate of $0.5625 per common unit and Class A unit to the unitholders of record at November 7, 2008. The distribution was paid on November 14, 2008.

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

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

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Distributions through December 31, 2007

On October 24, 2007, the Company declared a distribution for the third quarter of 2007 to the unitholders of record at November 7, 2007. The distribution was paid to holders of common units and Class A units at a rate of $0.5625 per unit on November 14, 2007. The increase in the distribution rate commenced a management incentive interest vesting period under the Company s operating agreement. An initial cash reserve of $0.1 million was established to fund future distributions on the management incentive interests. See Note 17 for additional information. A distribution of $0.3 million was paid to the holder of the Company s Class D interests on November 14, 2007.

On August 14, 2007, the Company paid a distribution for the second quarter 2007 to the unitholders of record at August 7, 2007. The distribution was paid to holders of common units and Class A units at a rate of $0.4625 per unit. The distribution was not paid to holders of Class F units or to the holders of common units issued in connection with the Amvest acquisition. See Note 2 for a discussion of the Amvest acquisition. A distribution of $0.3 million was paid to the holder of the Company s Class D interests on August 14, 2007.

On May 15, 2007, the Company paid a distribution for the first quarter of 2007 to the unitholders of record at May 8, 2007. The distribution was paid to holders of common units, Class A units and Class E units at a rate of $0.4625 per unit. A distribution of $0.3 million was paid to the holder of the Company s Class D interests on May 15, 2007.

On February 14, 2007, the Company paid a distribution for the fourth quarter of 2006 to the unitholders of record at February 7, 2007, prorated from the date of the Company s initial public offering on November 20, 2006. The distribution was paid to holders of common units and Class A units at a rate of $0.2111 per unit.

14. MEMBERS EQUITY

2008 Equity

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

At December 31, 2008, the Company had granted 39,579 units of the 450,000 units available under its long-term incentive plan. Of these grants, 5,343 have vested and 34,236 are unvested.

2007 Equity

At December 31, 2007, the Company had 447,022 Class A units and 21,904,106 Class B units outstanding, which included 5,343 restricted unvested common units. The Company has authorized 447,022 Class A units and 23,348,763 Class B units.

At December 31, 2007, the Company had granted 5,343 units of the 450,000 units available under its long-term incentive plan. Of these grants, 5,343 are unvested.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2007 Issuances

During 2007, the Company issued 11,030,828 units for proceeds of $369.5 million, net of issuance costs of $5.5 million.

In September 2007, the Company sold 2,470,592 common units representing Class B limited liability company interests in a private placement which generated proceeds of approximately $105 million.

In July 2007, the Company sold 3,371,219 Class F units representing limited liability company interests and 2,664,998 common units representing Class B limited liability company interests in a private placement which generated proceeds of approximately $210 million. On October 12, 2007, a special meeting of CEP s common unitholders was held. At this meeting, the common unitholders approved the conversion of all outstanding Class F units into common units. As a result of the approval, all 3,371,219 of the Company s outstanding Class F units were canceled and the same number of common units were issued to the former holders of the Class F units. To facilitate the conversion, the common unitholders approved both a change in the terms of the Company s Class F units to provide that each Class F unit is convertible into the Company s common units, and the issuance of additional common units upon the conversion of the Class F units.

In April 2007, the Company sold 90,376 Class E units representing limited liability company interests and 2,207,684 common units representing Class B limited liability company interests in a private placement for an aggregate purchase price of approximately $60 million. On June 26, 2007, a special meeting of CEP s common unitholders was held. At this meeting, the common unitholders approved the conversion of all outstanding Class E units into common units. As a result of the approval, all 90,376 of the Company s outstanding Class E units were canceled and the same number of common units were issued to the former holders of the Class E units. To facilitate the conversion, the common unitholders approved both a change in the terms of the Company s Class E units to provide that each Class E unit is convertible into the Company s common units, and the issuance of additional common units upon the conversion of the Class E units.

2006 Initial Public Offering

In the fourth quarter of 2006, the Company completed its initial public offering of an aggregate of 5,175,000 units representing Class B limited liability company interests (consisting of 4,500,000 units purchased by the underwriters on November 20, 2006 and 675,000 units purchased by the underwriters on November 28, 2006 pursuant to their option to purchase additional units) at an initial public offering price of $21.00 per unit in a firm commitment underwritten initial public offering pursuant to Registration Statement on Form S-1 (File No. 333-134995) declared effective by the Securities and Exchange Commission on November 14, 2006. Citigroup and Lehman Brothers Inc. acted as joint lead-managing underwriters of the offering.

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 SFAS 69, *Disclosures about Oil and Gas Producing Activities.* 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.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Supplemental information is also provided for per unit production costs; oil and natural gas production and average sales prices; the estimated quantities of proved oil and natural gas reserves; the standardized measure of discounted future net cash flows associated with proved reserves and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved reserves.

Costs

The following table sets forth capitalized costs for the years ended December 31, 2008, 2007, and 2006:

	December 31, 2008	December 31, 2007 (In 000 s)	December 31, 2006
Capitalized costs at the end of the period:[(a)]			
Oil and natural gas properties and related equipment (successful efforts method)			
Property (acreage) costs			
Proved property	$ 729,898	$ 635,224	$ 181,747
Unproved property	38,293	39,018	88
Total property costs	768,191	674,242	181,835
Materials and supplies	4,587	2,880	1,264
Land	912	902	160
Total	773,690	678,024	183,259
Less: Accumulated depreciation, depletion and amortization	(111,171)	(34,371)	(11,620)
Net capitalized cost	$ 662,519	$ 643,653	$ 171,639

(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, 2008, 2007, and 2006:

		CEP	
	For the year ended December 31, 2008	For the year ended December 31, 2007 (In 000 s)	For the year ended December 31, 2006
Costs incurred for the period:			
Acquisition of properties			
Proved	$ 47,665	$ 436,847	$
Unproved	398	42,544	85
Exploration costs			
Development costs	47,897	23,645	13,400

Total costs incurred	$ 95,960	$ 503,036	$ 13,485

The development costs for the years ended December 31, 2008, 2007, and 2006 primarily represent costs to develop our proved undeveloped reserves. We estimate that we will spend $26.0 million, $27.5 million, and $25.6 million to develop our proved undeveloped reserves in 2009, 2010, and 2011, respectively.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Results of Operations

The revenues and expenses associated directly with oil and natural gas producing activities are reflected in the Consolidated Statements of Operations. Substantially all of CEP s 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.

	For the year ended December 31, 2008	CEP For the year ended December 31, 2007 (In MMcfe)	For the year ended December 31, 2006
Beginning Balance	302,787	120,336	112,025
Extensions and discoveries	5,628	12,300	
Purchases of reserves in place	12,738	158,012	
Sales of reserves in place			
Revisions of previous estimates	(71,355)	22,532	12,952
Production	(17,384)	(10,393)	(4,641)
Ending Balance	232,414	302,787	120,336
Total proved developed reserves	159,027	186,693	97,387

Reserves and Related Estimates

CEP s 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.

CEP s 2008, 2007 and 2006 proved reserve estimates were 232.4 Bcfe, 302.8 Bcfe and 120.3 Bcfe. For these years, NSAI, an independent petroleum engineering firm, prepared an estimate of CEP s proved reserves. NSAI s estimates of our 2008 proved reserves were used to prepare our financial statements. NSAI s estimates of our 2007 and 2006 proved reserves were materially consistent with our internal estimate report.

CEP s 2008 estimates of proved reserves decreased from 2007 primarily due to reserve revisions due to a lower year-end price for natural gas and slightly higher estimates of oilfield service and drilling costs offset by our acquisition of reserves in the Woodford Shale and additions from our development programs in the Cherokee Basin. Our reserves are 99% natural gas and are sensitive to lower year end prices for natural gas and basis differentials in the Mid-Continent region. The year end natural gas price used to prepare our reserve report was $6.14 for NYMEX and $4.59 in the Cherokee Basin. Although we utilize swaps, options and basis swaps to mitigate commodity price risk and basis differentials, these derivatives are not used when preparing our reserve report based on SEC rules. This low year end SEC price makes many of our proved undeveloped locations uneconomic in the Cherokee Basin and dramatically reduced the SEC value of our Woodford Shale reserves. No reserves were attributed to the Torch NPI in 2008.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CEP s 2007 estimates of proved reserves increased from 2006 primarily due to our acquisitions in the Cherokee Basin and our development drilling programs. Our reserve revisions are primarily a result of a higher year-end natural gas price. No reserves were attributed to the Torch NPI.

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

The assumptions used to compute estimated future cash inflows do not necessarily reflect expectations of actual revenues or costs or their present value. In addition, variations from expected production rates could result directly or indirectly from factors outside of CEP s 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:

		CEP	
	For the year ended December 31, 2008	**For the year ended December 31, 2007**	**For the year ended December 31, 2006**
		(In 000 s)	
Future cash inflows	$ 1,201,327	$ 1,965,708	$ 677,866
Future production costs	(500,184)	(749,166)	(257,502)
Future estimated development costs	(161,146)	(207,286)	(64,673)
Future net cash flows	539,997	1,009,256	355,691
10% annual discount for estimated timing of cash flows	(311,083)	(528,825)	(235,504)
Standardized measure of discounted estimated future net cash flows related to proved gas reserves	$ 228,914	$ 480,431	$ 120,187

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	CEP		
	For the year Ended December 31, 2008	For the year Ended December 31, 2007 (In 000 s)	For the year Ended December 31, 2006
Beginning of the period	$ 480,431	$ 120,187	$ 295,435
Sales and transfers of natural gas, net of production costs	(81,179)	(41,257)	(40,064)
Net changes in prices and production costs related to future production	(130,792)	91,935	(193,499)
Development costs incurred during the period	46,194	26,115	12,292
Changes in extensions and discoveries	9,502	14,447	
Revisions of previous quantity estimates	(112,789)	20,848	18,435
Purchase of reserves in place	50,248	228,279	
Accretion discount	48,043	19,877	29,624
Other	(80,744)		(2,036)
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 228,914	$ 480,431	$ 120,187

16. SUPPLEMENTAL QUARTERLY FINANCIAL DATA (Unaudited)

	2008 Quarters Ended(a)			
	March 31,	June 30,	September 30, (In 000 s)	December 31,
Total revenue	$ 28,469	$ 23,961	$ 59,650	$ 51,159
Operating expenses	21,300	25,923	25,640	57,082
General and administrative expenses	3,335	3,787	3,800	3,490
Net income (loss)	$ 1,501	$ (8,790)	$ 26,939	$ (12,382)
Earnings per unit Basic	$ 0.07	$ (0.39)	$ 1.21	$ (0.56)
Earnings per unit Diluted	$ 0.07	$ (0.39)	$ 1.21	$ (0.56)

	2007 Quarters Ended			
	March 31,	June 30,	September 30, (In 000 s)	December 31,
Total revenue	$ 8,525	$ 12,571	$ 26,171	$ 28,602
Operating expenses	4,144	7,495	14,434	20,090
General and administrative expenses	1,619	1,771	2,667	3,052
Net income	$ 2,254	$ 2,193	$ 6,883	$ 2,911
Earnings per unit Basic	$ 0.20	$ 0.17	$ 0.37	$ 0.13
Earnings per unit Diluted	$ 0.20	$ 0.17	$ 0.37	$ 0.13

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2006 Quarters Ended(b)			
	March 31,	June 30,	September 30,	December 31,
	(In 000 s)			
Total revenue	$ 9,747	$ 7,858	$ 8,549	$ 10,763
Operating expenses	4,269	4,017	4,468	3,848
General and administrative expenses	1,095	1,636	714	1,128
Net income	$ 4,432	$ 2,353	$ 3,531	$ 5,673
Earnings per unit Basic				
Earnings per unit Diluted				

(a) In connection with our 2008 quarterly financial statements, we recorded an immaterial non-cash adjustment related to the first quarter of 2008 during the fourth quarter of 2008. This adjustment was not considered to be material to our condensed consolidated financial statements for the three month period ended December 31, 2008, nor were such items considered to be material to any of our prior quarterly financial statements during 2008. As such, this table reflects the impact of recording the non-cash adjustment in the first quarter of 2008. The net impact of this non-cash adjustment was a decrease to our net income in the amount of $0.9 million for the three months ended March 31, 2008 and an increase to our net income of $0.9 million for the three months ended December 31, 2008. There was no impact of this adjustment on the twelve months ended December 31, 2008.

(b) CEP completed its initial public offering during the fourth quarter of 2006. There were no outstanding units prior to this offering; therefore, net income (loss) per unit information is not meaningful to present.

17. SUBSEQUENT EVENTS

Distribution

On January 24, 2009, the Company declared a distribution for the fourth quarter of 2008 at a rate of $0.13 per common unit and Class A unit to the unitholders of record at February 6, 2008. The distribution was paid on February 13, 2009.

Management Incentive Interests

For the third quarter 2007, the Company increased its distribution rate to $0.5625 per unit. This increase in the distribution rate commenced a management incentive interest vesting period under the Company s operating agreement. Through December 31, 2008, a cash reserve of $0.7 million had been established to fund future distributions on the management incentive interests. In February 2009, the Company reduced its distribution rate to $0.13 per unit. This decrease in the distribution rate terminated the initial management incentive interest vesting period. After the February 13, 2008 distribution was paid, the reserve was reduced to zero.

Torch NPI

On January 8, 2009, the Company was served by Trust Venture, on behalf of the Trust, with a purported derivative action filed in Alabama state court demanding an audited statement of revenues and expenses associated with the NPI, alleging a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserting that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit seeks unspecified damages and an accounting of the NPI. On February 9, 2009, the Company filed a motion to dismiss the lawsuit and filed an arbitration proceeding against the Trust relating to the claims alleged in the lawsuit with Judicial Arbitration and Mediation Services (JAMS). On February 12, 2009 Trust Venture requested a stay of the arbitration proceeding. The Company intends to defend itself vigorously with respect to the alleged claims. On February 25, 2009, the Circuit Court of Tuscaloosa County, Alabama denied the Company s motion to dismiss the lawsuit and also denied Trust Venture s motion to stay the arbitration proceeding. There can be no assurance as to the outcome or result of the lawsuit or the arbitration proceeding. The Company intends its forward-looking statements relating to the action to speak only as of the time of such statements and does not plan to update or revise them except to the extent that material information becomes available.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Class D Interests

In connection with litigation related to the Torch NPI, the Company has suspended all quarterly cash contributions with respect to the Company s Class D interests. This suspension includes the $333,333.33 quarterly cash distribution for the three months ended December 31, 2008 and $999,999.99 which represents the distributions that were suspended for the quarterly periods ended September 30, June 30, and March 31, 2008. The remaining undistributed amount of the Class D interests is $6.7 million.

Management Services Agreement

In February 2009, the conflicts committee of the Company s board of managers approved $1.7 million in maximum annual charges for 2009 under the management services agreement with Constellation.

Debt

As of February 20, 2009, the Company had $220.0 million in outstanding debt under its reserve-based credit facilities.

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SCHEDULE II

CONSTELLATION ENERGY PARTNERS LLC

VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2008, 2007 and 2006

(In 000 s)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2008					
Environmental reserves	$ 546	$ (105)			$ 441
2007					
Environmental reserves	$ 721	$ (175)			$ 546
2006					
Environmental reserves	$ 721				$ 721

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Constellation Energy Partners LLC, the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONSTELLATION ENERGY PARTNERS LLC

(REGISTRANT)

Date: February 23, 2009

By /s/ STEPHEN R. BRUNNER
Stephen R. Brunner

Chief Executive

Officer, Chief Operating Officer and President

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

Signature	Title	Date
Principal executive officer and manager:		
By /s/ STEPHEN R. BRUNNER **Stephen R. Brunner**	Chief Executive Officer, Chief Operating Officer and President	February 23, 2009
Principal financial officer and treasurer:		
By /s/ CHARLES C. WARD **Charles C. Ward**	Chief Financial Officer and Treasurer	February 23, 2009
Managers:		
/s/ STEPHEN R. BRUNNER **Stephen R. Brunner**	Manager	February 23, 2009
/s/ RICHARD H. BACHMANN **Richard H. Bachmann**	Manager	February 23, 2009
/s/ JOHN R. COLLINS **John R. Collins**	Manager	February 23, 2009
/s/ RICHARD S. LANGDON **Richard S. Langdon**	Manager	February 23, 2009
/s/ JOHN N. SEITZ	Manager	February 23, 2009

John N. Seitz

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EXHIBIT INDEX

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC and Constellation Energy Partners, LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007).
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).
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).
2.4	Purchase and Sale Agreement dated as of August 2, 2007, between Newfield Exploration Mid-Continent Inc. and Constellation Energy Partners LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
2.5	Nominee Agreement, dated as of September 21, 2007, by and between Newfield Exploration Mid-Continent Inc. and CEP Mid-Continent LLC (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
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)
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)
3.3	Amendment No. 1 to 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 April 24, 2007)
3.4	Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC dated July 25, 2007. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
3.5	Amendment No. 3 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC dated September 21, 2007 (incorporated by reference to Exhibit 3.5 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
4.1	Registration Rights Agreement, dated as of April 23, 2007, by and between Constellation Energy Partners LLC and the Purchasers named therein (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007).
4.2	Registration Rights Agreement, dated July 25, 2007, by and between Constellation Energy Partners LLC and the purchasers named therein. (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
4.3	Registration Rights Agreement, dated September 21, 2007, by and between Constellation Energy Partners LLC and the purchasers named therein (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007)

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Exhibit Number	Description
10.1	Credit Agreement dated as of October 31, 2006 by and among Constellation Energy Partners LLC, as borrower, The Royal Bank of Scotland plc, as administrative agent, RBS Securities Corporation, as lead arranger and sole bookrunner, BNP Paribas and Wachovia Bank N.A., as co-syndication agents and the lenders from time to time party thereto (incorporated herein by reference to Exhibit 10.1 to Amendment No. 4 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on November 2, 2006 (Amendment No. 4))
10.2	Management Services Agreement dated as of November 20, 2006 by and between Constellation Energy Partners LLC and Constellation Energy Partners Management, LLC (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.3	Omnibus Agreement dated as of November 20, 2006 by and among Constellation Energy Partners LLC, Constellation Energy Commodities Group, Inc., Robinson s Bend Production II, LLC, Robinson s Bend Operating II, LLC and Robinson s Bend Marketing II, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.4	Net Overriding Royalty Conveyance dated as of November 22, 1993 but effective as of October 1, 1993, pursuant to Part I thereof, from Velasco Gas Company, Ltd. to Torch Energy Advisors Incorporated, and pursuant to Part II thereof, from Torch Energy Advisors Incorporated to the Torch Energy Royalty Trust (incorporated herein by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on September 29, 2006 (Amendment No. 2))
10.5	Oil and Gas Purchase Agreement dated as of October 1, 1993 by and among Torch Energy Marketing, Inc., Torch Royalty Company and Velasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2)
10.6	Letter agreement dated as of June 13, 2005 by and between Robinson s Bend Marketing II, LLC and Torch Energy TM, Inc. (incorporated herein by reference to Exhibit 10.6 to Amendment No. 2)
10.7	International Swap Dealers Association, Inc. Master Agreement and Schedule dated as of June 16, 2006 between The Royal Bank of Scotland, plc and Constellation Energy Resources LLC (incorporated herein by reference to Exhibit 10.7 to Amendment No. 2)
10.8	Confirmation, dated June 28, 2006, effective June 20, 2006, between The Royal Bank of Scotland, plc and Constellation Energy Resources LLC (incorporated herein by reference to Exhibit 10.8 to Amendment No. 2)
10.9	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)
10.10	Letter agreement as of October 24, 2006 by and among The Investment Company LLC, Constellation Energy Commodities Group, Inc. and Robinson s Bend Production II, LLC (incorporated herein by reference to Exhibit 10.10 to Amendment No. 4)
10.11	Trademark License Agreement dated as of November 20, 2006 by and between Constellation Energy Group, Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.12	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)

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Exhibit Number	Description
10.13	Class E Unit and Common Unit Purchase Agreement, dated as of March 8, 2007, by and among Constellation Energy Partners LLC and the Purchasers named therein (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007).
10.14	First Amendment to Credit Agreement, dated as of April 4, 2007, by and among Constellation Energy Partners LLC and the Lenders signatory thereto (incorporated herein by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on May 10, 2007).
10.15	Class F Unit and Common Unit Purchase Agreement, dated July 12, 2007, by and between Constellation Energy Partners LLC and the purchasers named therein. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
10.16	Common Unit Purchase Agreement, dated August 2, 2007, by and between Constellation Energy Partners LLC and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
10.17	Water Gathering and Disposal Agreement by and among Torch Energy Associates Ltd., a Texas limited partnership, and Velasco Gas Company Ltd., a Texas limited partnership, dated August 9, 1990.
10.18	First Amendment to Water Gathering and Disposal Agreement by and among Torch Energy Associates Ltd., a Texas limited partnership, and Velasco Gas Company Ltd., a Texas limited partnership, dated October 1, 1993.
10.19	Second Amendment to Water Gathering and Disposal Agreement, by and among Robinson s Bend Operating Company, LLC, a Delaware company, successor in interest to Torch Energy Associates Ltd., a Texas limited partnership, and Everlast Energy LLC, a Delaware company, successor in interest to Velasco Gas Company Ltd., a Texas limited partnership, dated November 30, 2004.
10.20	Letter Agreement dated December 31, 2008 between Constellation Energy Partners LLC and Stephen R. Brunner
10.21	Letter Agreement dated December 31, 2008 between Constellation Energy Partners LLC and Charles C. Ward.
*10.22	Letter Agreement dated December 31, 2008 between Constellation Energy Partners LLC and Lisa J. Mellencamp.
*10.23	Exploration and Development Agreement
*10.24	Substituted and Replaced First Amendment to the Exploration and Development Agreement
*10.25	Assignment, Assumption and Ratification Agreement under the Exploration and Development Agreement
*10.26	Clarification Agreement to the Credit Agreements, dated as of February 24, 2009, by and among Constellation Energy Partners LLC and the Lenders Signatory thereto.
*12.1	Computation of Ratio of Earnings to Fixed Charges
*21.1	List of subsidiaries of Constellation Energy Partners LLC
*23.1	Consent of PricewaterhouseCoopers LLP
*23.2	Consent of Netherland, Sewell & Associates, Inc.
*31.1	Certification Chief Executive Officer, Chief Operating Officer, and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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Exhibit Number	Description
*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.

* Filed herewith