Filed Pursuant to Rule 424(b)(3)
Registration No. 333-144388

PROSPECTUS

2,298,060 Common Units
Representing Class B Limited Liability Company Interests

This prospectus relates up to 2,298,060 common units representing Class B limited liability company interests in us that may be offered for resale by the selling unitholders named in this prospectus. The selling unitholders acquired the common units in a private placement transaction occurring in April 2007. We are registering the offer and sale of the common units to satisfy registration rights we granted in that transaction.

We are not selling any common units under this prospectus and will not receive any proceeds from the sale of common units by the selling unitholders. The common units to which this prospectus relates may be offered and sold from time to time directly from the selling unitholders or alternatively through underwriters or broker-dealers or agents. The common units may be sold in one or more transactions, at fixed prices, at prevailing market prices at the time of sale or at negotiated prices. Because all of the common units being offered under this prospectus are being offered by the selling unitholders, we cannot currently determine the price or prices at which our common units may be sold under this prospectus.

Our common units are listed for trading on NYSE Arca under the trading symbol "CEP." On November 23, 2007, the closing sale price of our common units as reported on NYSE Arca was $32.50 per unit.

Investing in our common units involves risks. See "Risk Factors" beginning on page 23.

These risks include the following:

- If commodity prices decline significantly, our cash from operations will decline, and we may have to reduce our quarterly cash distributions or may not be able to pay cash distributions at all.
- 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 you.
- We rely on an affiliate of Constellation Energy Group, Inc., or Constellation, to identify and evaluate for us prospective oil and natural gas properties for acquisition. Constellation and its affiliates have no obligation to present us with such potential acquisitions, and, if they fail to do so, we may not be able to replace or increase our reserves, which would adversely affect our cash from operations and our ability to make cash distributions to you.
- Our operations require substantial capital expenditures, which will reduce our cash available for distribution. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves and production.
- Constellation and its affiliates own a significant interest in us through their ownership of all of our Class A limited liability company interests and 27% of our outstanding common units. Constellation and its affiliates have conflicts of interest with us and no fiduciary duties to us. The ultimate resolution of these conflicts of interest may result in favoring the interests of Constellation and its other affiliates over yours and may be to our detriment.
- We benefit from a gas purchase contract that will be terminated if a third-party royalty trust is terminated. The termination of the royalty trust is an event that is beyond our control.
- You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

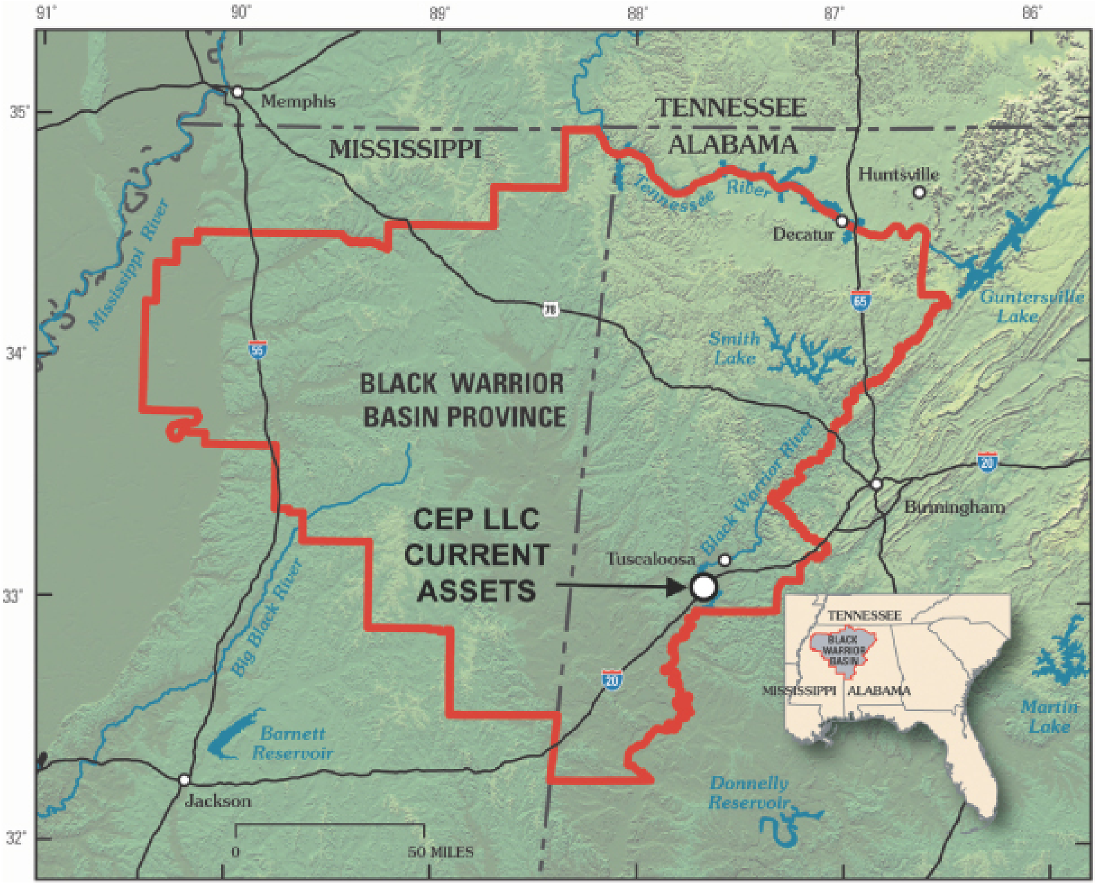
Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

December 6, 2007

[Table of Contents](#)

Constellation Energy Partners LLC

We are a limited liability company focused on the acquisition, development and exploitation of oil and natural gas properties as well as related midstream assets. Our 120.3 Bcf of estimated proved reserves at December 31, 2006 were 100% natural gas and were located in the Robinson's Bend Field in Alabama's Black Warrior Basin.



[Table of Contents](#)

In April 2007, we completed our first acquisition of oil and natural gas properties in the Cherokee Basin of Oklahoma and Kansas and interests in certain limited liability companies which own oil and natural gas properties in the Cherokee Basin (the "EnergyQuest Assets").

In July 2007, we completed the acquisition of additional oil and natural gas properties in the Cherokee Basin of Oklahoma via an agreement of merger providing for the merger of Amvest Osage, Inc. into a wholly-owned subsidiary of CEP (the "Amvest Acquisition").

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

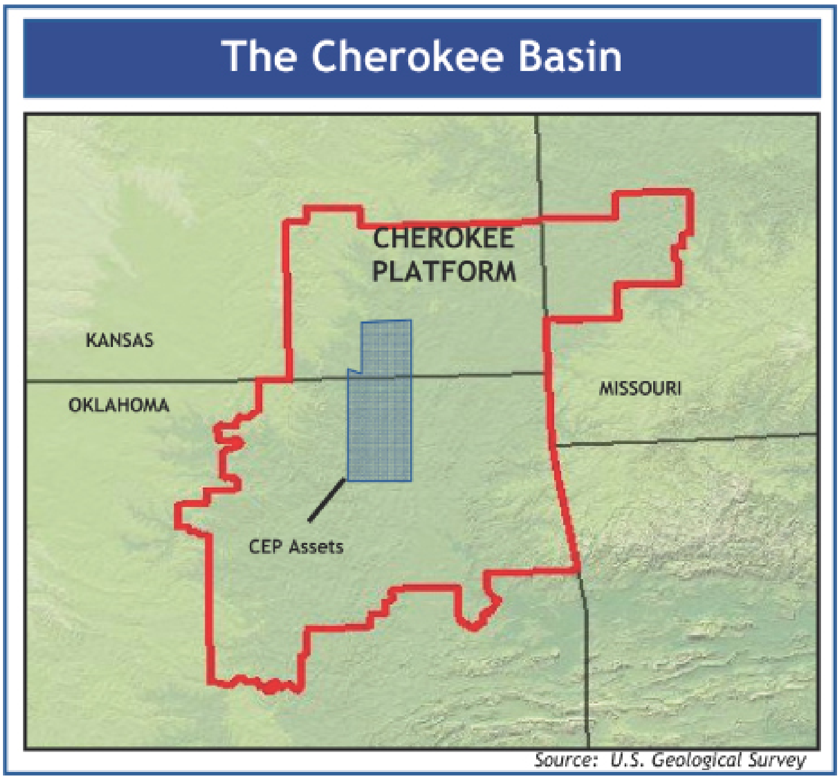


TABLE OF CONTENTS

SUMMARY	1
Constellation Energy Partners LLC	1
The Offering	10
Summary Historical and Pro Forma Consolidated Financial Data	16
Non-GAAP Financial Measure—Adjusted EBITDA	19
Summary Reserve and Operating Data	21
RISK FACTORS	23
Risks Related to Our Business	23
Risks Related to Our Structure	39
Tax Risks to Unitholders	43
CAUTIONARY NOTE REGARDING FORWARD–LOOKING STATEMENTS	47
CHEROKEE BASIN ACQUISITIONS	48
Natural Gas Data	50
Productive Wells	50
Developed and Undeveloped Acreage	50
Leases	50
Operations	51
Marketing and Major Customers	52
Hedging Activity	52
Financing	54
USE OF PROCEEDS	55
CAPITALIZATION	56
PRICE RANGE OF COMMON UNITS AND DISTRIBUTIONS	57
HOW WE MAKE CASH DISTRIBUTIONS	58
Initial Quarterly Distributions	58
Distributions of Available Cash	58
Operating Surplus and Capital Surplus	58
Distributions of Available Cash from Operating Surplus	62
Management Incentive Interests	62
Percentage Allocations of Available Cash from Operating Surplus	64
Distributions from Capital Surplus	65
Quarterly Cash Distributions on our Class D Interests	66
Distributions of Cash Upon Liquidation	66
SELECTED HISTORICAL AND PRO FORMA CONSOLIDATED FINANCIAL DATA	68
Non-GAAP Financial Measure—Adjusted EBITDA	71
SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT	73
CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS	75
Distributions and Payments to CCG, CEPH, CEP Equity II LLC, CHI and CEPM	75
Agreements with Constellation Affiliates	77
Trademark License	79
Cash Pool Arrangement	79
CONFLICTS OF INTEREST AND FIDUCIARY DUTIES	81
Conflicts of Interest	81
Fiduciary Duties	83
DESCRIPTION OF THE COMMON UNITS	84
The Common Units	84
Transfer Agent and Registrar	84
Transfer of Common Units	84

Table of Contents

THE LIMITED LIABILITY COMPANY AGREEMENT	86
Organization	86
Purpose	86
Fiduciary Duties	86
Agreement to be Bound by Limited Liability Company Agreement; Power of Attorney	86
Capital Contributions	86
Limited Liability	87
Voting Rights	87
Issuance of Additional Securities	88
Election of Members of Our Board of Managers	88
Amendment of Our Limited Liability Company Agreement	89
Merger, Sale or Other Disposition of Assets; Conversion	91
Termination and Dissolution	91
Liquidation and Distribution of Proceeds	92
Anti-Takeover Provisions	92
Limited Call Right	93
Meetings; Voting	93
Non-Citizen Assignees; Redemption	94
Indemnification	94
Books and Reports	95
Right To Inspect Our Books and Records	95
Registration Rights	95
MATERIAL TAX CONSEQUENCES	96
Partnership Status	96
Common Unitholder Status	98
Tax Consequences of Unit Ownership	98
Tax Treatment of Operations	104
Disposition of Units	107
Uniformity of Units	109
Tax-Exempt Organizations and Other Investors	110
Administrative Matters	111
State, Local and Other Tax Considerations	113
INVESTMENT IN OUR COMPANY BY EMPLOYEE BENEFIT PLANS	114
PLAN OF DISTRIBUTION	115
SELLING UNITHOLDERS	117
VALIDITY OF THE UNITS	118
EXPERTS	118
WHERE YOU CAN FIND MORE INFORMATION	119

APPENDIX A— Glossary of Terms A-1

You should rely only on the information contained in this prospectus. We have not authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. You should assume that the information appearing in this prospectus is accurate as of the date on the front cover of this prospectus only. Our business, financial condition, results of operations and prospects may have changed since that date.

SUMMARY

This summary highlights information contained elsewhere in this prospectus. You should read the entire prospectus carefully, including the historical and pro forma consolidated financial statements and the notes to those financial statements. You should read "Risk Factors" for information about important factors to consider before buying the common units. We include a glossary of some of the terms used in this prospectus in Appendix A. We have prepared the estimates of proved natural gas reserves described in this prospectus, including the reserve estimates contained in the financial statements included elsewhere in this prospectus. As described in more detail under the caption "Summary Reserve and Operating Data," in preparing the estimates as of December 31, 2006 and 2005 included in the financial statements for the year ended December 31, 2005 and the estimates included elsewhere in this prospectus, we made certain downward adjustments to the reserve estimates as of December 31, 2005 prepared by Netherland, Sewell & Associates, Inc., or NSAI. In preparing the reserve estimates as of December 31, 2004 used to prepare the financial statements of our predecessor for 2004, we made other adjustments to the reserve estimates as of December 31, 2005 prepared by NSAI to rollback those estimates for actual production, prices and development as described in more detail in our most recent Annual Report on Form 10-K for the year ended December 31, 2006 that are incorporated herein by reference. We have removed from our reserve and Standardized Measure estimates confirmed in this prospectus estimated amounts attributable to the Torch Royalty NPI by treating the NPI as an overriding royalty interest.

References in this prospectus to "Constellation Energy Partners," "we," "our," "us," "CEP" or like terms refer to Constellation Energy Partners LLC and its subsidiaries. References in this prospectus to "CEPM" are to Constellation Energy Partners Management, LLC, a Delaware limited liability company. References in this prospectus to "CCG" are to Constellation Energy Commodities Group, Inc., a Delaware corporation. References in this prospectus to "CEPH" are to Constellation Energy Partners Holdings, LLC, a Delaware limited liability company. References to "CHI" are to Constellation Holdings, Inc., a Delaware corporation. References in this prospectus to "Constellation" are to Constellation Energy Group, Inc., a Maryland corporation. We refer to our Class A limited liability company interests as the Class A units, our Class B limited liability company interests as the common units, our Class C limited liability company interests as the management incentive interests, our Class D limited liability company interests as the Class D interests, our Class E limited liability company interests as the Class E units and our Class F limited liability company interests as the Class F units.

Constellation Energy Partners LLC

We are a limited liability company that was formed by 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 and over time to increase our quarterly cash distribution. As of December 31, 2006, our estimated proved reserves are 100% natural gas and are located in the Robinson's Bend Field in Alabama's Black Warrior Basin. Our estimated proved reserves at December 31, 2006 were approximately 120.3 Bcf, approximately 81% of which were classified as proved developed. Our average proved reserve-to-production ratio is approximately 24 years based on our estimated proved reserves at January 1, 2006 and production for the year ended December 31, 2006. We currently own a 100% working interest (an approximate 75% average net revenue interest, calculated before the Torch Royalty NPI, or NPI, described below) in our Robinson's Bend Field producing properties, which had 467 producing natural gas wells as of December 31, 2006.

On April 23, 2007, we closed the acquisition of the EnergyQuest Assets for approximately $115 million, subject to purchase price adjustments. On July 25, 2007, we closed the Amvest Acquisition for approximately

$240 million, subject to purchase price adjustments. On September 21, 2007, we closed the acquisition of the Newfield Assets for approximately $128 million, subject to purchase price adjustments. Please read "—EnergyQuest Acquisition", "—Amvest Acquisition" and "—Newfield Acquisition" for additional information on these acquired properties and on the Cherokee Basin.

For a further description of the characteristics of coalbed methane production and the Black Warrior Basin, please read our most recent Annual Report on Form 10-K for the year ended December 31, 2006 and our Quarterly Report on Form 10-Q for the quarter ended September 30, 2007 that are incorporated herein by reference.

On June 20, 2006, we executed part of a commodity price risk management program that is intended to reduce the volatility in our revenues due to commodity price changes, which in turn should provide greater stability to our future cash flows and earnings. Pursuant to this program, we have hedged the future prices of a portion of our expected production from October 2006 through December 2009 from currently producing wells. Under our broader hedge program, we have adopted a policy that contemplates hedging the sales prices for approximately 80% of our expected production from currently producing wells for a period of up to five years, as appropriate, based primarily on our intent to stabilize cash flows and our view of prevailing and expected market conditions for natural gas. In determining our initial quarterly distribution, or IQD, we have taken into account the resulting impact of these hedges. For a further description of our hedging activities, please read our most recent Annual Report on Form 10-K for the year ended December 31, 2006 and our Quarterly Report on Form 10-Q for the quarter ended September 30, 2007 that are incorporated herein by reference.

Recent Developments

Conversion of Class E Units

At a special meeting of our common unitholders held on June 26, 2007, our common unitholders approved the conversion of all outstanding Class E units into common units. As a result of the approval, all 90,376 of our outstanding Class E units were cancelled and the same number of common units were issued to the former holders of Class E units. To facilitate the conversion, the common unitholders approved both a change in the terms of our Class E units to provide that each Class E unit is convertible into our common units, and the issuance of additional common units upon the conversion of the Class E units.

Amvest Acquisition

On July 25, 2007, we closed the Amvest Acquisition for approximately $240 million, subject to purchase price adjustments. We also completed a private placement of 2,664,998 common units and 3,371,219 newly-created Class F units at an average price of $34.79 per unit which generated proceeds of approximately $210 million. On October 12, 2007, our common unitholders approved the conversion of the Class F units into common units, on a one-for-one basis. We also agreed to file a registration statement with the Securities Exchange Commission ("SEC") registering for resale the common units and common units issuable upon conversion of the Class F units within 90 days after the closing of the acquisition. The proceeds from this equity private placement, together with borrowings under our existing credit facility, fully funded the purchase price of the acquisition. We also entered into derivative transactions to hedge a portion of the future expected production associated with this acquisition. Immediately prior to the closing of the acquisition, the seller deposited $8.5 million into a drilling fund escrow account to be used for post-closing drilling development and operational costs and expenses related to the Amvest Acquisition assets. These funds have been released from escrow.

Newfield Acquisition

On September 21, 2007, we closed the acquisition of the Newfield Assets for approximately $128 million, subject to purchase price adjustments. We also completed a private placement for 2,470,592 common units at a price of $42.50 per unit which generated proceeds of approximately $105 million. We have agreed to file a registration statement with the SEC registering for resale the common units within 90 days after the closing of the acquisition. The proceeds from this equity private placement, together with borrowings under our existing credit facility, fully funded the purchase price of the acquisition. We also entered into derivative transactions to hedge a portion of the future expected production associated with this acquisition. Upon the issuance of the equity securities, affiliates of CCG now own approximately 29% of the outstanding limited liability company interests of CEP.

Torch Energy Royalty Trust

In August 2007, Torch Energy Royalty Trust (the "Trust") announced that Trust Venture Company, LLC had requested the Trust's trustee to call a special meeting of unitholders to consider and vote upon a proposal to terminate the Trust. According to the Trust's quarterly report on Form 10-Q for the quarter ended September 30, 2007, Trust Venture Company, LLC informed the Trust on November 14, 2007 that it was revoking its request for a special meeting of the unitholders to terminate the Trust. For a further discussion of the Trust, please read "—Torch Royalty NPI and "Risk Factors—Risks Related to Our Business—A group of investors in the Trust may seek to terminate the Trust, which termination could reduce our future revenues and adversely affect our results of operations and our ability to pay cash distributions."

Conversion of Class F Units

At a special meeting of our common unitholders held on October 12, 2007, our 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 our outstanding Class F units were cancelled and the same number of common units were issued to the former holders of Class F units. To facilitate the conversion, the common unitholders approved both a change in the terms of our Class F units to provide that each Class F unit is convertible into our common units, and the issuance of additional common units upon the conversion of the Class F units.

Third Quarter Distribution

On October 24, 2007, we announced a cash distribution for the third quarter ending September 30, 2007, of $0.5625 per unit, or $2.25 per unit on an annualized basis, for all of our outstanding common and Class A units. The distribution was paid on November 14, 2007, to unitholders of record at the close of business on November 7, 2007. The increase in the distribution rate will commence a management incentive interest vesting period under our operating agreement. An initial cash reserve of $0.1 million has been established to fund future distributions on the management incentive interests.

Business Strategies

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 by executing our business strategy, which is to:

- 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;
- increase reserves and production through what we believe to be low-risk development drilling; and
- reduce the volatility in our revenues resulting from changes in oil and natural gas commodity prices through hedging.

Competitive Strengths

We believe we are positioned to successfully execute our business strategies because of the following competitive strengths from which we benefit:

- our relationship with Constellation;
- operational and technical support from Constellation;
- low-risk development drilling operations;
- predictable, long-lived reserves;
- control of operations; and
- large undeveloped acreage base.

EnergyQuest Acquisition

General

On April 23, 2007, we completed an acquisition of the EnergyQuest Assets from EnergyQuest Resources, LP ("EnergyQuest") for approximately $111.2 million, subject to purchase price adjustments. The EnergyQuest assets consist of:

- certain coalbed methane properties with estimated proved reserves of 43 Bcf;
- over 600 gross producing wells on approximately 96,000 gross acres; and
- support equipment, gathering pipelines and facilities.

In addition, we also purchased a 50% membership interest in five operating subsidiaries from a subsidiary of EnergyQuest for approximately $3.8 million, subject to purchase price adjustments. The EnergyQuest operating subsidiaries own:

- 31 wells located in Oklahoma;
- approximately 225 miles of gathering pipelines; and
- an operating company for the field support operations.

Please read "Cherokee Basin Acquisitions" beginning on page 48 for more information about the acquisition of the EnergyQuest Assets and the EnergyQuest operating subsidiaries, collectively, the "EnergyQuest Acquisition." Please read "—Summary Historical and Pro Forma Financial and Operating Data" for more information on the financial and operating results regarding the EnergyQuest Assets.

Financing

We financed the purchase price of the EnergyQuest Acquisition with:

- the private placement of 2,207,684 common units and 90,376 Class E units at a price of $26.12 per unit and $25.84 per unit, respectively, which generated net proceeds to us of approximately $60 million; and
- funds available under our revolving credit facility.

Amvest Acquisition

General

On July 25, 2007, we completed an acquisition of AMVEST Osage, Inc., a subsidiary of AMVEST Corporation ("Amvest"), for approximately $240 million, subject to purchase price adjustments. Amvest owns oil and gas properties in the Cherokee Basin of Oklahoma. The Amvest assets consist of:

- certain oil and natural gas properties with estimated proved reserves of 71 Bcfe;
- approximately 370 producing wells generally with 100% working interest; and
- 13 year exclusive concession from the Osage Nation for coalbed methane and shale rights on approximately 560,000 net contiguous acres.

Please read "Cherokee Basin Acquisitions" for more information about the Amvest Acquisition. Please read "—Summary Historical and Pro Forma Financial and Operating Data" for more information regarding the Amvest Acquisition's financial and operating results.

Financing

We financed the purchase price of the Amvest Acquisition with:

- the private placement of 2,664,998 common units and 3,371,219 Class F units at an average price of $34.79 per unit, which generated net proceeds to us of approximately $210 million; and
- funds available under our revolving credit facility.

Newfield Acquisition

General

On September 21, 2007, we completed an acquisition of certain oil and gas properties and related assets located in the Cherokee Basin of Oklahoma from Newfield Exploration Mid-Continent, Inc. ("Newfield") for approximately $128 million, subject to purchase price adjustments. The Newfield assets consist of:

- certain coalbed methane properties with estimated proved reserves of 44 Bcfe;
- over 600 net producing wells with an average working interest of approximately 94% on approximately 80,000 net acres; and
- approximately 350 miles of pipeline gathering systems.

Please read "Cherokee Basin Acquisitions" for more information about the acquisition of the Newfield Assets ("Newfield Acquisition"). Please read "—Summary of Historical and Pro Forma Financial and Operating Data" for more information on the financial and operating results regarding the Newfield Acquisition.

Financing

We financed the purchase price of the Newfield Acquisition with:

- the private placement of 2,470,592 common units at an average price of $42.50 per unit, which generated net proceeds to us of approximately $105 million; and
- funds available under our revolving credit facility.

Cherokee Basin Hedging Activity

In connection with the EnergyQuest Acquisition, the Amvest Acquisition and the Newfield Acquisition (collectively, the "Cherokee Basin Acquisitions"), we expect to enter into and have entered into hedging transactions with unaffiliated third parties with respect to natural gas prices to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in natural gas prices. Please read “Cherokee Basin Acquisitions—Hedging Activity” beginning on page 52 for more information on our hedging activity with respect to the assets acquired in the Cherokee Basin Acquisitions.

Our Relationship with Constellation

We believe that one of our principal strengths is our relationship with Constellation, an integrated energy company with 2006 revenues of approximately $19.3 billion and total assets of approximately $21.8 billion as of December 31, 2006. Constellation’s common stock trades on The New York Stock Exchange under the symbol “CEG.” Constellation is engaged in numerous aspects of the energy industry, including, through CCG, oil and natural gas exploration and production, or E&P, natural gas transportation, natural gas storage and physical and financial natural gas trading.

A principal component of our business strategy is to grow our asset base and production through the acquisition of E&P properties characterized by long-lived, stable production. Constellation, through CCG, has a track record of successfully acquiring developed and undeveloped E&P properties. CCG is currently developing several other E&P projects in various locations with unconventional production, including coalbed methane, tight sands and shale. As CCG continues to develop the E&P properties that comprise these projects, and potentially other undeveloped E&P properties that it may acquire in the future, it is possible these projects will have characteristics of properties suitable for us and our business strategies. Constellation views us as an integral component of the growth strategy for its upstream oil and natural gas business and intends to use us as its primary vehicle to develop a portfolio of long-lived, proved producing E&P properties. However, Constellation has no obligation or commitment to do so, and may act in a manner that is beneficial to its interests and detrimental to ours.

We have entered into a management services agreement with CEPM, an indirect wholly-owned subsidiary of Constellation. Pursuant to that agreement, CEPM provides us with legal, accounting, finance, tax, property management, engineering and risk management services and may provide us with acquisition services in respect of opportunities for us to acquire long-lived, stable and proved oil and natural gas reserves. While neither Constellation nor CEPM has any obligation to provide us with acquisition services under the management services agreement, we expect that their ownership of our Class A units, common units and management incentive interests will provide them with an incentive to grow our business by helping us to identify, evaluate and complete acquisitions that will be accretive to our distributable cash.

We reimburse CEPM for the reasonable costs of the services it provides to us. Our board of managers has the right and the duty to review the services provided, and the costs charged, by CEPM under the management services agreement. Our board of managers may in the future cause us to hire additional personnel to supplement or replace some or all of the services provided by CEPM, as well as employ third-party service providers. If we were to take such actions, they could increase the overall costs of our operations. For a description of the services that CEPM provides to us and our obligation to reimburse CEPM for the costs it incurs in providing those services, please read “Certain Relationships and Related Party Transactions—Agreements Governing the Transactions—Management Services Agreement.”

While our relationship with Constellation and its subsidiaries is a significant strength, it is also a source of potential conflicts. For example, none of Constellation or any of its affiliates is restricted from competing with us, and each of our executive officers and our Class A managers also serves as a manager, director, officer or employee of Constellation or its other affiliates. Constellation or its affiliates may acquire, invest in or dispose of E&P or other assets in the future without any obligation to offer us the opportunity to purchase or own interests in those assets. The ultimate resolution of the conflicts of interest that exist or arise as a result of either our relationship with Constellation and its other affiliates or the status of our executive officers or our Class A managers as managers, directors, officers or employees of Constellation or its other affiliates may result in the interests of Constellation or its affiliates being favored over your interests and may be to our detriment. Please read “Conflicts of Interest and Fiduciary Duties.”

Cash Distribution Policy

Our board of managers had adopted a cash distribution policy to pay a regular quarterly distribution of $0.4625 per unit on our outstanding common and Class A units while reinvesting in our business a portion of our operating cash flow. In October 2007, our board of managers approved an increase of our regular quarterly distribution from $0.4625 per unit to $0.5625 per unit on our outstanding common and Class A units. The increase in our regular quarterly distribution will commence a management incentive interest vesting period under our operating agreement. We paid our latest cash distribution of $0.5625 per unit for our outstanding common and Class A units on November 14, 2007 to unitholders of record on November 7, 2007 for the quarter ended September 30, 2007. Declaration and payment of distributions is at the discretion of our board of managers, and we cannot assure you that we will not reduce or eliminate our distributions.

In general, it is our policy to distribute all of our available cash after paying our operating expenses and retaining an amount of funds that our board of managers estimates is adequate for the proper conduct of our business, including the maintenance of our asset base. If we continue this policy, we will be dependent on our ability to raise debt and equity from the capital markets to grow our asset base, and we cannot assure you of our ability to access such markets. If our board of managers underestimates the amounts necessary to maintain our asset base or we fail to invest those funds effectively, our board of managers will likely need to reduce the amount of our distributions. In an effort to reduce the uncertainty regarding our distributions, our board of managers intends to increase our distributions per unit only if it believes that (i) we have sufficient reserves and liquidity for the proper conduct of our business, including the maintenance of our asset base, and (ii) we can maintain such increased distribution level for a sustained period.

Pursuant to the terms of our limited liability company agreement, our board of managers has the discretionary authority to cause us to borrow funds from our reserve-based credit facility to make up a shortfall in cash available for distribution. Under our reserve-based credit facility, we will be able to incur debt to pursue our business plan and to pay distributions to our unitholders, provided that our borrowings do not reach or exceed 90% of the borrowing base and that we are not then in default.

Torch Royalty NPI

The majority of our properties in the Robinson’s Bend Field are subject to a non-operating net profits interest (“NPI”) held by Torch Energy Royalty Trust (the “Trust”). Through the NPI, the Trust is entitled to a royalty payment, calculated as a percentage of the net revenue, that is, specified revenues reduced by specified expenditures, from specified wells in the Robinson’s Bend Field (the “Trust Wells”). As of December 31, 2006, we owned a working interest in 467 producing wells in the Robinson’s Bend Field, of which 421 wells were subject to the NPI. We estimate that, as of December 31, 2005, approximately 5.8 Bcf of proved reserves were attributable to the NPI on the Trust Wells, which we have excluded from our estimate of proved reserves attributable to our interests in the Robinson’s Bend Field. At December 31, 2006, we estimated that no proved reserves were attributable to the NPI on the Trust Wells because of natural gas prices at that time.

Under the terms of the NPI and related contractual arrangements, the royalty payment we are required to make to the Trust under the NPI is calculated using a sharing arrangement with a pricing formula that has resulted in below-market prices and has had the effect of keeping our payments to the Trust significantly lower than if such payments had been calculated based on then prevailing market prices. No amounts were due to the Trust in 2005 in respect of the NPI. We paid the Trust approximately $0.2 million in the aggregate for January 2006 through December 2006 production from the Trust Wells in respect of the NPI.

The sharing arrangement may be terminated under specified circumstances that are beyond our control. If we lose the benefit of the sharing arrangement in respect of calculating payments under the NPI, our payments to the Trust will increase and our revenues will decrease. For a further description of the NPI and the related contractual arrangements, as well as the circumstances under which the sharing arrangement may be terminated, please read our most recent Annual Report on Form 10-K for the year ended December 31, 2006, our Quarterly Report on Form 10-Q and Current Report on Form 8-K that are incorporated herein by reference.

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, CHI has contributed to us $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. On November 14, 2007, the most recent distribution of $333,333 was paid to CHI, as holder of the Class D interests. If the amounts payable by us to the Trust are not calculated based on the 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 interests will cease receiving the special quarterly cash distributions; and the Class D interests will only be returned the remaining undistributed amount of the $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 reduce, but not eliminate, the adverse impact of our reduced revenues from the termination of the sharing arrangement. For a further description of this special distribution right, please read "Certain Relationships and Related Party Transactions—Distributions and Payments to CCG, CEPH, CEP Equity II LLC, CHI and CEPM—Operational Stage."

Risk Factors

An investment in our common units involves risks associated with our business, regulatory and legal matters, our limited liability company structure and the tax characteristics of our common units. Please read carefully the risks under the caption "Risk Factors" immediately following this Summary beginning on page 23.

Principal Executive Offices and Internet Address

Our principal executive offices are located at 111 Market Place, Baltimore, Maryland 21202, and our telephone number is (410) 468-3500. Our website is located at *http://www.constellationenergypartners.com*. We make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission ("SEC") available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

[Table of Contents](#)

Organizational Chart

The following diagram depicts our organizational structure as of October 31, 2007.

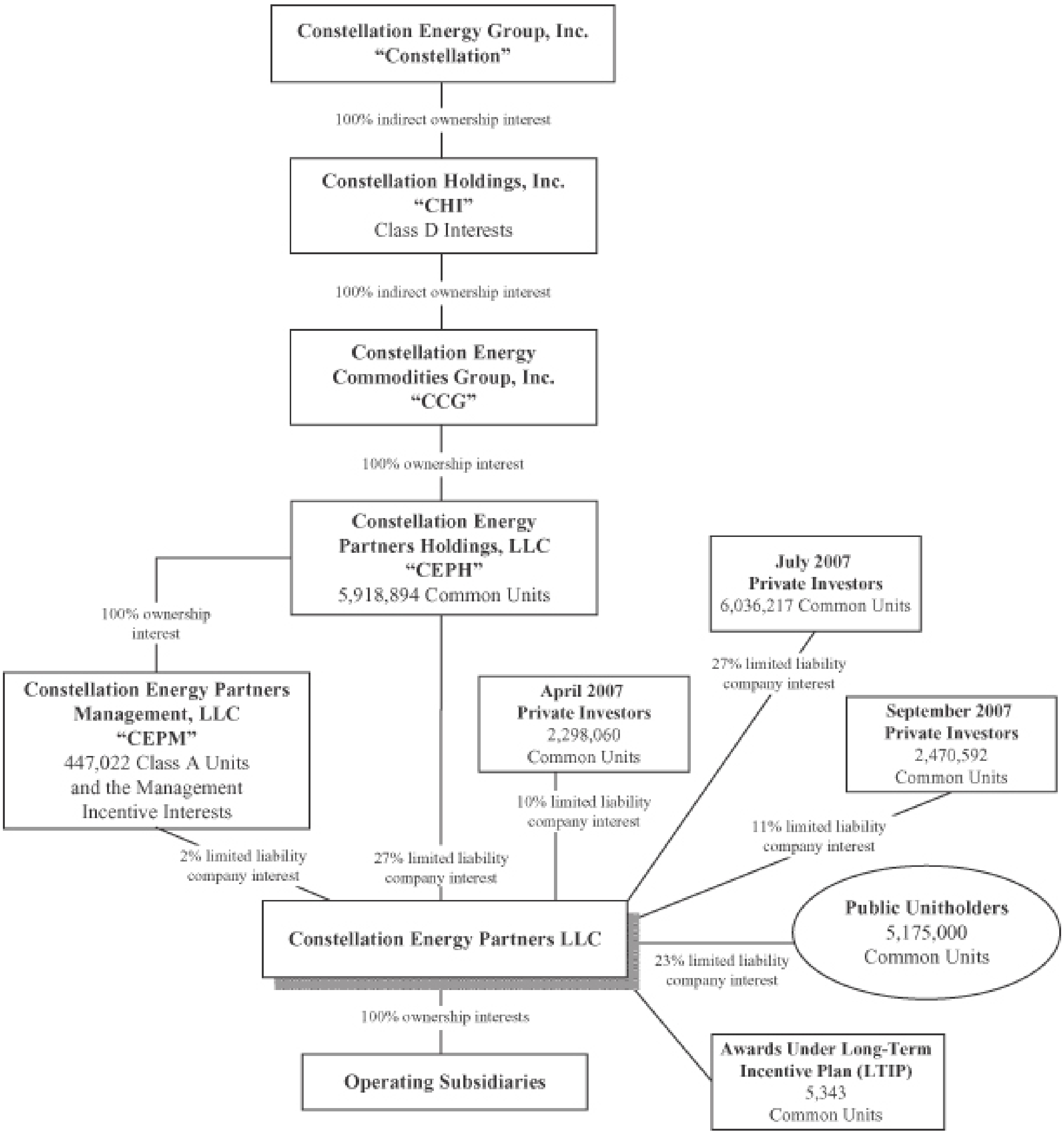


Table of Contents

The Offering

Units offered by selling unitholders	2,298,060 common units.
Units outstanding after this offering	21,904,106 common units, which includes 5,343 common units granted under our long-term incentive plan. 447,022 Class A units, all of which are owned by CEPM.
Use of proceeds	We will not receive any proceeds from sales of common units by the selling unitholders.
Cash distributions	We intend to make a current quarterly distribution of $0.5625 per common unit to the extent we have sufficient available cash from operations after we establish appropriate cash reserves and pay fees and expenses, including payments to CEPM for reimbursement of costs and expenses it incurs on our behalf. In October 2007, our board of managers approved an increase of our regular quarterly distribution from $0.4625 per unit to $0.5625 per unit on our outstanding common and Class A units. We refer to this cash as “available cash,” and we define its meaning in more detail in our limited liability company agreement, in “How We Make Cash Distributions—Distributions of Available Cash—Definition of Available Cash” and in the glossary of terms found in Appendix A. Our board of managers has broad discretion in establishing cash reserves. The cash reserves that our board of managers may establish in its discretion include reserves for future cash distributions on the common units, Class A units and management incentive interests and to pay special cash distributions to the holders of our Class D interests. These reserves, which could be substantial, will reduce the amount of cash available for distribution to you. Our board of managers has adopted a policy that it will raise our quarterly cash distribution only when it believes that we (i) have sufficient reserves and liquidity for the proper conduct of our business, including the maintenance of our asset base, and (ii) can maintain such increased distribution level for a sustained period. While this is our current policy, our board of managers may alter such policy in the future when and if it determines such alteration to be appropriate. Our limited liability company agreement requires that, within 45 days after the end of each calendar quarter beginning with the quarter ending December 31, 2006, we distribute all of our available cash to holders of record of our limited liability company interests on the applicable record date. On November 14, 2007, for each of our common and Class A units, we paid to unitholders of record on November 7, 2007 the most recent cash distribution of $0.5625 per unit for the quarter ended September 30, 2007.

The amount of available cash in any quarter may be greater or less than the aggregate amount associated with payment of an initial quarterly distribution of $0.4625 per common unit ("IQD") on all of our common units and Class A units. In general, we pay any cash distributions we make in the following manner:

- *first*, 98% to the holders of our common units and 2% to the holders of our Class A units, pro rata, until each unitholder has received $0.5319 (that is, the $0.4625 IQD plus $0.0694), which aggregate amount we refer to as the "Target Distribution;" and
- *thereafter*, any amount distributed in respect of any quarter in excess of the Target Distribution will be distributed 98% to the holders of our common units, pro rata, and 2% to the holder of our Class A units until distributions become payable in respect of our management incentive interests as described under "Management incentive interests" below.

The holder of our Class A units is entitled to 2% of our cash distributions without any obligation to make future capital contributions to us.

Management incentive interests

We refer to a distribution in respect of the management incentive interests as a "management incentive distribution." CEPM initially holds all of the management incentive interests.

Payments to the holder of our management incentive interests are subject to the satisfaction of certain requirements. The first requirement is the "12-Quarter Test." The 12-Quarter Test requires that, for the 12 full, consecutive, non-overlapping calendar quarters that begin with the first calendar quarter in respect of which we pay per unit cash distributions from operating surplus to holders of Class A and common units in an amount equal to or greater than the Target Distribution (we refer to such 12-quarter period as the "First MII Earnings Period"):

- we pay cash distributions from operating surplus to holders of our outstanding Class A and common units in an amount that on average exceeds the Target Distribution on all of the outstanding Class A and common units over the First MII Earnings Period;
- we generate adjusted operating surplus (which is defined in "How We Make Cash Distributions" and in the glossary included as Appendix A) during the First MII Earnings Period that on average is in an amount at least equal to 100% of all distributions on the outstanding Class A and common units up to the Target Distribution plus 117.65% of all such distributions in excess of the Target Distribution; and
- we do not reduce the amount distributed per unit in respect of any such 12 quarters.

The second requirement is the "4-Quarter Test." The 4-Quarter Test requires that, for each of the last four full, consecutive, non-overlapping calendar quarters in the First MII Earnings Period:

- we pay cash distributions from operating surplus to the holders of our outstanding Class A and common units that exceed the Target Distribution on all of the outstanding Class A and common units;
- we generate adjusted operating surplus in an amount at least equal to 100% of all distributions on the outstanding Class A and common units up to the Target Distribution plus 117.65% of all such distributions in excess of the Target Distribution; and
- we do not reduce the amount distributed per unit in respect of any of such four quarters.

If the 12-Quarter Test and the 4-Quarter Test have been met, then: (i) we will make a one-time management incentive distribution (contemporaneously with the distribution paid in respect of the Class A and common units for the twelfth calendar quarter in the First MII Earnings Period) to the holder of our management incentive interests equal to 17.65% of the sum of the cumulative amounts, if any, by which quarterly cash distributions per unit paid on the outstanding Class A and common units during the First MII Earnings Period exceeded the Target Distribution on all of the outstanding Class A and common units (we refer to this one-time management incentive distribution as an "EP MID"); and (ii) for each calendar quarter after the First MII Earnings Period, the holders of our Class A units and common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay for such quarter in excess of the Target Distribution.

If the 12-Quarter Test is not met, management incentive distributions will not be payable in respect of the First MII Earnings Period. An EP MID may become payable, however, with respect to a subsequent period, which we refer to as the Later MII Earnings Period, if the 12-Quarter Test and the 4-Quarter Test are met in respect of such Later MII Earnings Period. If both tests are met with respect to a Later MII Earnings Period, then for each calendar quarter after the Later MII Earnings Period, the holders of the Class A units, common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay for such quarter in excess of the Target Distribution.

However, if (a) the 12-Quarter Test has been met in respect of the First MII Earnings Period or any Later MII Earnings Period, but not the 4-Quarter Test; (b) the 4-Quarter Test has been met in any period of four full, consecutive and non-overlapping quarters occurring after the end of the First MII Earnings Period or Later MII Earnings

Table of Contents

Period, as the case may be, up to three of which quarters can fall within the First MII Earnings Period or Later MII Earnings Period, as the case may be, (we refer to such four-quarter period as the "MII 4-Quarter Earnings Period"); and (c) we have paid at least the IQD in each calendar quarter occurring between the end of the First MII Earnings Period or Later MII Earnings Period, as the case may be, and the beginning of the MII 4-Quarter Earnings Period:

- the holders of our Class A units, common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay in excess of the Target Distribution for each calendar quarter after the MII 4-Quarter Earnings Period; and
- the holder of our management incentive interests will receive an EP MID with respect to the First MII Earnings Period or Later MII Earnings Period, as the case may be.

The increase of our regular quarterly distribution from $0.4625 per unit to $0.5625 per unit on our outstanding common and Class A units will commence the First MII Earnings Period. An initial reserve of $0.1 million has been established to fund future distributions on the management incentive interests.

We are not able to predict the amount of the distributions in respect of the management incentive interests. For a further discussion of the management incentive interests, please read the information set forth under the caption "How We Make Cash Distributions–Management Incentive Interests."

Special Class D interests distribution

In order to address the risks of early termination, without the prior consent of our board of managers, of the sharing arrangement in respect of the calculation of amounts payable to the Trust for the NPI and the potential reduction in our revenues resulting therefrom, CHI has contributed $8.0 million to us for all of our Class D interests. For each full calendar quarter during the period commencing January 1, 2007 and ending on December 31, 2012 that the sharing arrangement remains in effect, we will distribute to the holder of the Class D interests $333,333.33, 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 unitholders for that quarter. On November 14, 2007, the most recent distribution of $333,333.33 was paid to CHI, as holder of the Class D interests. The Class D interests will be cancelled upon the payment of the final distribution of $333,333.41 to CHI for the quarter ending December 31, 2012, unless the special distribution right has been terminated earlier. 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 and the remaining portion of the $8.0 million contribution not so returned in special cash distributions

	will be retained by us to partially offset the reduction in our revenues resulting from termination of the sharing arrangement in respect of the Trust. In the case of such termination of the special distribution right, CHI will have the right only 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 distribution right is terminated during a quarter, the special distribution to the holder of the Class D interests will be pro rated 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.
Issuance of additional units	We can issue an unlimited number of additional limited liability company interests without the consent of our unitholders. Please read "Risk Factors—Risks Related to Our Structure—We may issue additional units without unitholder approval, which would dilute existing unitholders' ownership interests," and "The Limited Liability Company Agreement—Issuance of Additional Securities."
Agreement to be bound by limited liability agreement; common unit voting rights	By purchasing a common unit, you will be admitted as a member of our limited liability company and be deemed to have agreed to be bound by all of the terms of our limited liability company agreement. Our board of managers manages us and will rely on personnel from CEPM and its affiliates to oversee our operations. Pursuant to our limited liability company agreement, as a common unitholder you will be entitled to vote on the following matters: • annual election of three members of our five-member board of managers; • specified amendments to our limited liability company agreement; • merger of our company or the sale of all or substantially all of our assets; and • dissolution of our company. Please read "The Limited Liability Company Agreement—Voting Rights."
Board of Managers	Our board of managers is comprised of five members, two of whom are elected by the holders of the Class A units and the remainder of whom are elected by the holders of the common units.
Limitations on common unitholder actions	Our limited liability company agreement (i) prohibits common unitholders from taking unitholder action by written consent and (ii) nullifies the common unitholder voting rights of any person other than Constellation or its affiliates that holds 20% or more of our outstanding common units.

Limited call right	If at any time any person and its affiliates own more than 80% of the outstanding common units, such person will have the right, but not the obligation, to purchase all of the remaining common units at a price not less than the then–current market price of the common units.
Fiduciary duties	Our limited liability company agreement provides that the fiduciary duties of our managers and officers are generally to act in good faith in acting on our behalf in such capacity. As a result of our relationship with Constellation and its affiliates, as well as the fact that our executive officers and Class A managers also serve as managers, directors, officers or employees of Constellation or its other affiliates, conflicts of interest exist and will arise in the future. The ultimate resolution of these conflicts of interest may result in the interests of Constellation or its affiliates being favored over your interests, may be to our detriment and could adversely affect the market price of the common units. If in resolving these conflicts of interest 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, you will not be able to assert that such resolution constituted a breach of fiduciary duty owed to us or to you by our board of managers and officers. For example, our limited liability company agreement establishes a conflicts committee of our board of managers, consisting solely of independent managers, which is responsible for reviewing transactions involving potential conflicts of interest. If the conflicts committee approves such a transaction, you will not be able to assert that such approval or the consummation of such transaction constituted a breach of fiduciary duties owed to you by our managers and officers.
Material tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please read “Material Tax Consequences.”
Exchange listing and trading symbol	Our common units are listed for trading on NYSE Arca under the trading symbol “CEP.”

Summary Historical and Pro Forma Consolidated Financial Data

Set forth below is our summary historical and unaudited pro forma consolidated financial data for the periods indicated. We were formed in February 2005 and had no operations prior to the completion of a $161.1 million acquisition of natural gas reserves and equipment in the Robinson's Bend Field from Everlast Energy LLC ("Everlast") on June 13, 2005. We applied the purchase method of accounting to the separable assets and liabilities of the natural gas properties and equipment acquired from Everlast. The summary historical consolidated financial data of Everlast for the period from January 1, 2005 through June 12, 2005 and as of and for the year ended December 31, 2004 have been derived from Everlast's audited historical financial statements. The summary historical financial data of Constellation Energy Partners LLC as of December 31, 2006 and 2005, for the year ended December 31, 2006, and for the period from February 7, 2005 (inception) through December 31, 2005, have been derived from our audited historical consolidated financial statements. The summary historical consolidated financial data of Constellation Energy Partners LLC as of and for the nine months ended September 30, 2007 and 2006 have been derived from our unaudited historical consolidated financial statements. The summary unaudited pro forma consolidated financial data for the nine months ended September 30, 2007 and for the year ended December 31, 2006 have been derived from our unaudited pro forma consolidated financial statements and other financial information from EnergyQuest, Amvest and Newfield. For a description of the adjustments made in the unaudited pro forma consolidated financial statements, please read the notes to those financial statements.

These pro forma combined condensed financial statements show the pro forma effect of:

- the EnergyQuest Assets, the Amvest Acquisition and the Newfield Assets.

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 GAAP. We explain this measure below 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.

You should read the following summary financial data in conjunction with our financial statements and the financial statements of Everlast and related notes appearing elsewhere in this prospectus. You should also read the pro forma information, together with the unaudited pro forma consolidated financial statements and related notes included in this prospectus.

Prior to the Cherokee Basin Acquisitions, our only operations were in the Robinson's Bend Field, as were Everlast's. During each of the last three years, our properties in the Robinson's Bend Field were wholly-owned by us or Everlast. Our acquisition from Everlast resulted in a new basis in our properties in the Robinson's Bend Field for accounting purposes. In addition, new management, operating and accounting policies, and accounting estimates were put into place after our acquisition from Everlast. Though the financial statements represent the operation of the same properties in the Robinson's Bend Field, due to these differences, the financial statements for the periods prior to and after our purchase of our properties in the Robinson's Bend Field 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 Robinson's Bend Field from Everlast may not be indicative of future results.

	Predecessor Everlast Energy LLC		Successor Constellation Energy Partners LLC					
							Pro Forma	
	For the year ended December 31, 2004	For the period from January 1, 2005 to June 12, 2005	For the period from February 7, 2005 (inception) to December 31, 2005[b]	For the year ended December 31, 2006	For the nine months ended September 30, 2006	For the nine months ended September 30, 2007	For the year ended December 31, 2006	For the nine months ended September 30, 2007
	As Restated[a]				Unaudited	Unaudited	Unaudited	Unaudited
	(In 000's)		(In 000's)					
Statement of Operations Data:								
Revenues:								
Oil and gas sales	$ 27,494	$ 12,882	$ 25,957	$ 36,917	$ 26,154	$ 50,033	$ 116,763	$ 95,493
Gain/(Loss) from mark-to-market activities	(9,107)	(15,313)	—	—	—	(2,766)	—	(2,766)
Total revenues	18,387	(2,431)	25,957	36,917	26,154	47,267	116,763	92,727
Operating expenses:								
Lease operating expenses	5,270	2,769	4,175	7,234	5,321	9,822	26,998	20,472
Cost of sales	—	—	—	—	—	656	1,481	1,486
Production taxes	1,479	676	1,400	1,783	1,340	2,136	6,227	4,716
General and administrative expenses	2,706	594	4,184	4,573	3,445	6,057	9,382	8,509
Loss on sale of asset	—	—	—	—	—	86	—	86
Depreciation, depletion and amortization	3,719	1,683	4,176	7,444	5,987	13,162	42,552	33,673
Accretion expense	86	46	78	141	106	211	583	431
Total operating expenses	13,260	5,768	14,013	21,175	16,199	32,130	87,223	69,373
Other expenses (income):								
Interest expense	3,028	2,437	3	221	2	4,209	9,851	8,468
Interest (income)	—	—	—	(468)	(363)	(303)	(468)	(340)
Other income	—	—	—	—	—	(99)	(12)	(99)
Total other expenses (income)	3,028	2,437	3	(247)	(361)	3,807	9,371	8,029
Total expenses	16,288	8,205	14,016	20,928	15,838	35,937	96,594	77,402
Net income (loss)	$ 2,099	$ (10,636)	$ 11,941	$ 15,989	$ 10,316	$ 11,330	$ 20,169	$ 15,325
Other Financial Information (unaudited):								
Adjusted EBITDA	$ 14,738	$ 8,795	$ 16,198	$ 23,025	$ 15,919	$ 32,946	$ 72,385	$ 61,894

(a) The financial statements of Everlast for 2004 have been restated. Please read Note 2 to the historical consolidated financial statements included elsewhere in this prospectus.
(b) Until our acquisition of our properties in the Robinson's Bend Field from Everlast on June 13, 2005, we did not conduct any operations.

Table of Contents

	Predecessor Everlast Energy LLC		Successor Constellation Energy Partners LLC			
	For the year ended December 31, 2004 As Restated[(a)]	For the period from January 1, 2005 to June 12, 2005	For the period from February 7, 2005 (inception) to December 31, 2005[(b)]	For the year ended December 31, 2006	For the nine months ended September 30, 2006 Unaudited	For the nine months ended September 30, 2007 Unaudited
	(In 000's)		(In 000's)			
Balance Sheet Data (at period end):						
Cash and cash equivalents	$ 2,012		$ 14,831	$ 7,485	$ 6,387	$ 19,519
Other current assets	4,562		6,097	18,602	27,242	27,174
Natural gas properties, net of accumulated depreciation, depletion and amortization	52,531		165,211	171,639	169,918	649,126
Other assets	1,579		—	5,971	6,400	20,495
Total assets	$ 60,684		$ 186,139	$ 203,697	$ 209,947	$ 716,314
Current liabilities	$ 4,482		$ 13,895	$ 9,007	$ 12,884	$ 23,538
Debt	67,500		63	22,000	—	147,000
Other long-term liabilities	3,314		3,014	2,730	3,160	10,699
Class D interests	—		—	8,000	—	7,333
Members equity:						
Common members equity (deficit)	(14,612)		169,167	148,847	179,853	515,003
Accumulated other comprehensive income	—		—	13,113	14,050	12,741
Total members' equity (deficit)	(14,612)		169,167	161,960	193,903	527,744
Total liabilities and members' equity (deficit)	$ 60,684		$ 186,139	$ 203,697	$ 209,947	$ 716,314
Cash Flow Data:						
Net cash provided by operating activities	$ 4,906	$ 6,639	$ 23,313	$ 14,067	$ 14,313	$ 33,260
Net cash used in investing activities	(6,997)	(4,203)	(147,237)	(25,429)	(22,694)	(499,749)
Net cash provided by (used in) financing activities	1,540	(2,500)	138,755	4,016	(63)	478,523
Development of natural gas properties	(5,680)	(4,000)	(8,286)	(13,224)	(10,071)	(17,679)

(a) The financial statements of Everlast for 2004 have been restated. Please read Note 2 to the historical consolidated financial statements included elsewhere in this prospectus.
(b) Until our acquisition of our properties in the Robinson's Bend Field from Everlast on June 13, 2005, we did not conduct any operations.

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;
- 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 flow 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.

Table of Contents

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

	Predecessor Everlast Energy LLC		Successor Constellation Energy Partners LLC				Pro Forma	
	For the year ended December 31, 2004	For the period from January 1, 2005 to June 12, 2005	For the period from February 7, 2005 (inception) to December 31, 2005	For the year ended December 31, 2006	For the nine months ended September 30, 2006	For the nine months ended September 30, 2007	For the year ended December 31, 2006	For the nine months ended September 30, 2007
					Unaudited	Unaudited	Unaudited	Unaudited
	(In 000's)		(In 000's)					
Reconciliation of Net Income (Loss) to Adjusted EBITDA:								
Net income (loss)	$ 2,099	$ (10,636)	$ 11,941	$ 15,989	$ 10,316	$ 11,330	$ 20,169	$ 15,325
Adjusted by:								
Interest expense (income), net[(a)]	3,028	2,437	3	(247)	(361)	3,906	9,383	8,128
Depreciation, depletion and amortization	3,719	1,683	4,176	7,444	5,987	13,162	42,552	33,673
Loss on sale of asset	—	—	—	—	—	86	—	86
Accretion of asset retirement obligation	86	46	78	141	106	211	583	431
Unrealized loss (gain) on natural gas derivatives	(2,156)	15,265	—	—	(129)	4,229	—	4,229
Long-term incentive plan	—	—	—	—	—	22	—	22
Realized loss (gain) on cancelled natural gas derivatives	7,962	—	—	(302)	—	—	(302)	—
Adjusted EBITDA	$ 14,738	$ 8,795	$ 16,198	$ 23,025	$ 15,919	$ 32,946	$ 72,385	$ 61,894

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

Summary Reserve and Operating Data

The following is a summary of our estimated net proved reserves attributable to our properties in the Robinson's Bend Field and summary unaudited information with respect to our production and sales of natural gas, all as of the dates indicated. We have prepared the estimates of proved natural gas reserves described in this prospectus. You should refer to "Risk Factors," and our historical consolidated financial statements in evaluating the material presented below.

On April 23, 2007, we closed the EnergyQuest Acquisition. On July 25, 2007, we completed the Amvest Acquisition. On September 21, 2007, we closed the Newfield Acquisition. Please read "Cherokee Basin Acquisitions—Natural Gas Data" for information on our estimated net proved natural gas reserves attributable to our properties in the Cherokee Basin.

The following table reflects our internal estimates of net proved natural gas reserves based on the 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 natural gas reserves.

	Predecessor	Successor	
	Everlast Energy LLC	Constellation Energy Partners LLC	
	As of December 31,		
Reserve data:	**2004**	**2005**	**2006**
Estimated net proved reserves:			
Natural gas (Bcf)	162.2	112.0	120.3
Proved developed reserves (Bcf)	101.4	89.3	97.4
Proved undeveloped reserves (Bcf)	60.8	22.7	22.9
Proved developed reserves as a percent of total reserves	62%	80%	81%
Standardized Measure (in millions)[(a)]	$ 206.8	$295.4	$120.2
Natural gas price—SONAT Gas Daily (price per MMbtu)[(b)]	$ 6.05	$10.06	$ 5.66

(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.

(b) Natural gas prices as of each period end were based on the Southern Natural Gas—Louisiana mid-point price, as published in Platts Gas Daily, which we refer to as the SONAT Gas Daily Price, on the last business day of the relevant period.

The data presented in the table above is based on our own internal estimates prepared for the predecessor and successor companies at the corresponding year ends and was used to prepare the financial statements presented elsewhere in this prospectus. Our 2005 estimates of proved reserves are lower than the 2004 estimates for Everlast, the predecessor company, because of the decision of CEP management to (i) reduce our future drilling program to 20 wells per year over the next six years, (ii) reflect our interpretation of well performance data from new wells drilled in the Robinson's Bend Field in 2004 and 2005, and (iii) reflect the impact of a revised refracture program. There was no drilling in the Robinson's Bend Field between 1994 and late 2003.

While the performance data from new wells in the Robinson's Bend Field at December 31, 2005 was limited, we believe it provided relevant information for the purposes of estimating reserves. The revised 20-well drilling program reflects our current intention of how we plan to develop the properties in the future. Our estimate of reserves at December 31, 2005 is also approximately 5.8 Bcf lower than the December 31, 2004 estimates of proved reserves due to a reduction for estimated reserves attributed to the NPI. No corresponding adjustment was made to the December 31, 2006 estimate because no amounts were due or paid in respect of the NPI at that time.

Our 2006 and 2005 proved reserve estimates were 120.3 Bcf and 112.0 Bcf, respectively. At December 31, 2006 and December 31, 2005, NSAI, an independent petroleum engineering firm, prepared an estimate of all our proved reserves. NSAI also prepared an updated report at our request to provide a sensitivity of the estimates of the NSAI December 31, 2005 reserves based on our reduced drilling program, our revised refracture program and the elimination of estimated reserves attributable to the NPI. NSAI's estimate of our 2006 and 2005 proved reserves is materially consistent with our internal estimate.

Our 2004 proved reserve estimate is 162.2 Bcf. This is our internal estimate of proved reserves that was used in the 2004 Everlast financial statements included elsewhere in this prospectus. We prepared the estimate of 2004 proved reserves for financial statement purposes by starting with NSAI's December 31, 2005 net proved reserve estimate, which was prepared based upon a continuation of the assumptions used by Everlast, including the prior accelerated drilling program and reserve assumptions, and rolling back the estimate to December 31, 2004 by making appropriate adjustments for actual production, prices and development activity. The roll back approach was necessary because the reserve report prepared by NSAI for Everlast as of December 31, 2004 was not based on the SEC definition of proved reserves, while the reserve report prepared by NSAI for Everlast as of December 31, 2003, which was based on the SEC definition of proved reserves, included different assumptions than those used by NSAI in preparing the December 31, 2005 proved reserves estimate. To prepare reserve estimates for this period in compliance with the SEC definitions, we adopted the roll-back approach described above and in Note 2 and Note 17 to the historical financial statements. Everlast's previous non-SEC compliant reserve estimate was 173.4 Bcf at December 31, 2004.

RISK FACTORS

Limited liability company interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should consider carefully the following risk factors, together with all of the other information included in this prospectus, in evaluating an investment in our common units.

The following risks could materially and adversely affect our business, financial condition or results of operations. If any of the events described below were to occur, we may not be able to pay quarterly distributions on our common units, the trading price of our common units could decline and you could lose part or all of your investment in our company.

Risks Related to Our Business

We may not have sufficient cash from operations to pay the distributions at our current quarterly distribution level following establishment of cash reserves and payment of fees and expenses, including payments to CEPM, and future distributions to our unitholders may fluctuate from quarter to quarter.

We may not have sufficient cash flow from operations each quarter to pay distributions at our current quarterly distribution level of $0.5625 per common unit following establishment of cash reserves and payment of fees and expenses, including payments to CEPM. 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 natural gas we produce; the demand for and the price at which we are able to sell our 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 and exploitation 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: our ability to make working capital borrowings under our reserve-based credit facility to pay distributions; our debt service requirements and restrictions on distributions contained in our reserve-based credit facility; fluctuations in our working capital needs; the timing and collectibility 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, 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 initial quarterly distribution amount that we expect to distribute. 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.

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.

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 natural gas and oil 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 natural gas and oil 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 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.

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. 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 Robinson’s Bend Field do not typically increase as the formation dewaters.

Our production from reserves in the Robinson’s Bend Field and in the Cherokee Basin 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. Thus, our future 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. We have prepared the estimates of proved natural gas reserves included in this prospectus, and such estimates are different from the estimates that may be determined by an independent petroleum engineering firm. Over time, our internal 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, we make certain assumptions regarding future 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 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 Mcf, then the Standardized Measure of our proved reserves as of December 31, 2006 would decrease from approximately $120.2 million to approximately $79.9 million. Our Standardized Measure is calculated using unhedged 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 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 providing 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 we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. 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.

Future price declines may result in a write-down of our asset carrying values.

Lower oil and natural gas prices may not only decrease our revenues, profitability and cash flows, but also reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. Substantial decreases in oil and natural gas prices would render a significant number of our planned exploitation 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 write-down of such carrying value. We may incur impairment charges in the future, which could result in a material reduction in our results of operations in the period taken and materially limit our ability to borrow funds under our reserve-based credit facility and our ability to make cash distributions to our unitholders.

We rely 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 rely 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. Pursuant to that agreement, we are required to use CEPM or its designee for legal, accounting, finance, tax and risk management services through December 31, 2007. CEPM will also provide 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. In the long term, without further acquisitions, we will 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, we plan to target 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. If we cannot find suitable third-party operators or our operators fail to perform under their contracts, we will need to hire additional personnel to operate our properties. Doing so will increase our costs and could adversely affect our cash from operations and our ability to make cash distributions.

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

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

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

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

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.

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

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.

Our Cherokee Basin acquisition activities will subject us to certain risks.

In April 2007, we acquired the EnergyQuest Assets for approximately $115 million, subject to purchase price adjustments. In July 2007, we completed the Amvest Acquisition for approximately $240 million, subject to purchase price adjustments. In September 2007, we acquired the Newfield Assets for approximately $128 million, subject to purchase price adjustments. 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 Cherokee Basin 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.

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 facility in the future to enable us to pay quarterly distributions. Significant declines in our production or significant declines in realized 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 facility to pay distributions rather than to maintain or expand our operations. If we use borrowings under our reserve-based credit facility to pay distributions for an extended period of time rather than toward funding 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.

Our reserve-based credit facility has substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations and our ability to pay distributions to our unitholders.

We will depend on our reserve-based credit facility for future capital needs and to fund a portion of our distributions. The reserve-based credit facility restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We are also required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under our reserve-based credit facility could result in a default under the facility, which could cause all of our existing indebtedness to be 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 the following two conditions occur: (i) a decrease by CEPH and CEPM of their combined ownership of our outstanding membership interests to less than 25%, 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 facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the reserve-based credit facility. Any increase in the borrowing base requires the consent of all the lenders. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other natural gas and oil properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the reserve-based credit facility.

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

We are prohibited from borrowing under our reserve-based credit facility to pay distributions to unitholders if the amount of borrowings outstanding under our reserve-based credit facility reaches or exceeds 90% of the borrowing base. Our borrowing base is the amount of money available for borrowing, as determined semi-annually by our lenders in their sole discretion. The lenders will redetermine the borrowing base based on an engineering report with respect to our natural gas reserves, which will take into account the prevailing natural gas prices at such time. 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.

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

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

- our ability to obtain additional financing, if necessary, for working capital, 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 arrangements 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 effect any of these remedies on satisfactory terms or at all.

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 expenses that it incurs on our behalf pursuant to the management services agreement. These expenses will include costs incurred on our behalf in performing accounting and financial and risk management services and some acquisition services, including costs for providing corporate staff and support services to us. CEPM charges on an allocated cost basis 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. The allocation of these costs for such personnel 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.

If the Trust is terminated, the gas purchase contract with the Trust will be terminated and payment by us to the Trust in respect of the NPI may cease being calculated by the sharing arrangement. As a result, 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 the Trust terminates on the earlier to occur of December 31, 2012 and the termination of the Trust. The Trust will terminate upon the first to occur of (i) an affirmative vote of the holders of not less than 66 2/3% of the outstanding Trust units to liquidate the Trust, and (ii) such time as the ratio of the cash amounts received by the Trust from the NPI to administrative costs of the Trust is less than 1.2 to 1.0 for three consecutive quarters. The Trust will also terminate on March 1 of any year if it is determined that the pre-tax future net cash flows, discounted at 10%, attributable to the estimated net proved reserves of the NPI on the preceding December 31 are less than $25.0 million. Based on natural gas reserve estimates at December 31, 2005 prepared by independent reserve engineers, the Trust advised its investors that, unless the Henry Hub spot price for natural gas on December 31, 2006 exceeded approximately $6.25 per MMBtu, the Trust would terminate on March 1, 2007. The Henry Hub spot price for natural gas on December 30, 2005 and December 29, 2006 was $10.08 per MMBtu and $5.64 per MMBtu, respectively. On March 2, 2007, the Trust advised that the value of the pre-tax future and cash flows, discounted at 10%, attributable to the estimated net proved reserves of the NPI as of December 31, 2006 exceeded $25.0 million and therefore, the Trust did not terminate as of March 1, 2007. Upon termination of the Trust, the gas purchase contract with TEMI, including the portion assigned to us, will terminate. Based upon our estimated production for the twelve months ending December 31, 2007 and the weighted average net realized sales price for our production used in calculating our Adjusted EBITDA for that twelve-month period, we estimate that, if the sharing arrangement in respect of the Trust was terminated, as of January 1, 2007, our revenues would be reduced by approximately $5.0 million during such twelve-month period and the $8.0 million contributed to us for the Class D interests would offset such a shortfall for approximately 1.6 years, if production and prices were to remain constant throughout such period.

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. Under the gas purchase contract, there is a sharing arrangement 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. If our payments to the Trust for the NPI ceased being calculated under the sharing arrangement, our royalty obligations under the NPI would be significantly higher based on current natural gas prices, which would reduce our revenues and could adversely affect our results of operations and our ability to pay cash distributions.

A group of investors in the Trust may seek to terminate the Trust, which termination could reduce our future revenues and adversely affect our results of operations and our ability to pay cash distributions.

On May 10, 2007, a group of investors, or the group, who held 3.7% of the outstanding Trust units, commenced a tender offer for the purpose of acquiring no less than 66 2/3% of the outstanding Trust units. According to their SEC filings, the group of investors intended to call a meeting of the Trust unitholders within one year of the date of the tender offer for the purpose of voting on the termination of the Trust. The Trust will terminate upon an affirmative vote of the holders of not less than 66 2/3% of the outstanding Trust units. On June 29, 2007, the group of investors announced that pursuant to an amended tender offer statement with the SEC that 2,360,664 Trust units were tendered in the offer, and that the group is the current owner of approximately 31% of the issued and outstanding Trust units. On August 1, 2007, the Trust announced that it had received and verified a request by Trust Venture Company, LLC to Wilmington Trust Company, not in its individual capacity but as trustee of the Trust, to call a special meeting of the unitholders and that Trust Venture Company, LLC is a unitholder owning of record more than 10% in number of the outstanding units of beneficial interests of the

Trust. Trust Venture Company, LLC stated the purpose of such special meeting was to consider and vote upon a proposal to terminate the Trust in accordance with the applicable provisions of the Trust agreement. According to the Trust's quarterly report on Form 10-Q for the quarter ended September 30, 2007, Trust Venture Company, LLC informed the Trust on November 14, 2007 that it was revoking its request for a special meeting of the unitholders to terminate the Trust. If the trust unitholders were to approve a termination of the Trust, whether or not upon a resolution submitted by such group, the Trust would be terminated, which in turn would terminate the gas purchase contract, which termination could reduce our future revenues and adversely affect our results of operations and our ability to pay cash distributions.

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. For the years ended December 31, 2006 and 2005, the monthly index price varied between a low of $4.18 and a high of $11.67, and a low of $6.12 and a high of $14.01, respectively.

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 approximately $2.22 during 2006 and $2.26 anticipated for 2007) 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, gross proceeds payable under the gas purchase contract 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. For example, during 2005 and 2006, the amount payable under the gas purchase contract was, on average, approximately $3.37 per MMBtu and $2.63 per MMBtu, respectively, less than the net average market price realized for the sale of such gas. If during the term of the gas purchase contract, 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.

While TEMI's interest in the gas purchase contract was assigned to one of our subsidiaries in June 2005, TEMI remains a nominal party to that contract and has obligations thereunder and the potential ability to make elections or even breach its obligations, both of which could adversely affect our rights and interests.

TEMI is an original party to the gas purchase contract. In connection with our acquisition of the Robinson's Bend Field properties from Everlast in June 2005, one of our subsidiaries assumed from TEMI all of its rights in respect of the Trust Wells under the gas purchase contract. As TEMI remains a nominal party to the gas purchase contract, it may still have the ability to make elections or even breach its obligations under the contract in a manner that affects our rights in respect of the Robinson's Bend Field. Any such action by TEMI could adversely impact our rights and interests. If TEMI breaches its obligations under the gas purchase contract, the gas purchase contract may terminate, which could similarly result in a termination of the rights assigned to us. Also, if TEMI elects to terminate the minimum price commitment, we could be required to use the applicable spot index price without the sharing arrangement to calculate the amounts payable by us to the Trust for the NPI, which could cause the royalty obligation in respect of the NPI to increase. Any such increase in our royalty obligation under the NPI could reduce our revenues and adversely affect our financial condition and results of operations and, as a result, our ability to pay cash distributions.

We depend on certain key customers for sales of our 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.

For the year ended December 31, 2006, five customers accounted for 100% of our total sales volumes at the Robinson's Bend Field. Specifically, Interconn Resources Inc., BP Energy Company, Enterprise Alabama, ConocoPhillips and Coral Energy Resources, L.P. accounted for approximately 30%, 20%, 18%, 17% and 15%, respectively, of our total sales volumes. In the Cherokee Basin, the majority of our sales of natural gas are to Scissortail Energy, LLC, CIMA Energy Ltd., and CCG. Our oil production is primarily purchased by Sunoco Inc. In July 2007, we entered into an agreement with Bear Energy LP to purchase the majority of our natural gas produced in the Robinson's Bend Field. To the extent these and other customers reduce the volumes of natural gas that they purchase from us and are not replaced by new customers, our revenues and cash available for distribution could decline.

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, we have adopted a policy that contemplates hedging approximately 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 natural gas prices we realize in our operations.

Our actual future production may be significantly higher or lower than we estimate at the time we enter 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.

We are exposed to trade 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 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.

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

We hold natural gas leases in the Robinson’s Bend Field and in the Cherokee Basin 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 Robinson’s Bend Field or in the Cherokee Basin, we will lose our right to develop the related properties.

Our business is difficult to evaluate because we have a limited operating history.

We were formed in February 2005 by Constellation to acquire E&P properties located in the Robinson’s Bend Field from Everlast in June 2005. Our assembled management team may not be able to successfully oversee our business and effectively implement our operating and growth strategies. Our financial results cover periods during which the natural gas properties that we acquired were not under the control or management of our current management team and therefore may not be indicative of our future financial or operating results. Our success will depend upon management’s ability to manage, operate and develop the properties that we currently own and those we may acquire in the future. Our failure to successfully manage, operate and develop these properties may have a significant adverse effect on our financial condition and results of operations.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, resulting in temporarily lower cash from operations, which may impact our ability to pay distributions.

Our management has specifically identified and scheduled drilling locations for our future multi-year drilling activities on our existing acreage in the Robinson’s Bend Field 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.

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.

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. 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.

Because we handle 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;
- 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 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 Robinson’s Bend Field. In addition, as a result of leaks from ponds used for 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.

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

Higher 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. 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.

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.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

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 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 natural gas and oil, 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 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 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.

Due to our lack of asset and geographic diversification, adverse developments in our two operating areas would reduce our ability to make distributions to our unitholders.

We rely exclusively on sales of the natural gas and oil that we produce. Furthermore, all of our assets are located in the Black Warrior Basin in Alabama and the Cherokee Basin in 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 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 production activities in the Robinson's Bend Field and the Cherokee Basin.

Natural gas operations in the Robinson's Bend Field and the Cherokee Basin are adversely affected by seasonal weather conditions, primarily during hurricane season and during periods of severe weather or extreme cold. We face the risk that power outages resulting from hurricanes and other strong storms will prevent us from operating our wells in an optimal manner.

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

Our 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 certain Native American tribal authorities. For example, a portion of our leases in the Cherokee Basin purchased pursuant to the Amvest Acquisition are regulated by a certain Native American tribe. 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.

Risks Related to Our Structure

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

Constellation indirectly owns approximately 27% of the outstanding common units and 100% of the outstanding Class A units as of October 31, 2007. 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, will have the exclusive right to elect two members of our board of managers.

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.

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 you have a claim relating to conflicts of interest or the resolution of such a conflict of interest.

The two members of our board of managers appointed by CEPM, the holder of our Class A units, are officers of, and are affiliated with, Constellation. In addition, our executive officers also serve as managers, directors, officers or employees 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;

- we intend to rely on CEPM to 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;
- 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;
- our executive officers will not be compensated by us; instead, they will be compensated by CCG for serving as officers or employees of CCG;
- we intend to 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.

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

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

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

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

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.

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 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.

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 natural gas and oil companies and securities of publicly traded limited partnerships and limited liability companies;
- 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 natural gas and oil companies;
- variations in the amount of our quarterly cash distributions;
- future issuances and sales of our common units; and
- changes in general conditions in the U.S. economy, financial markets or the oil and natural gas industry.

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.

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.

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. The new owner of the Class A units and common units formerly owned by Constellation would then be in a position to assert great influence to replace a majority of our board of managers with its own choice, which could then replace some or all of our officers.

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

As of October 31, 2007, CEPH controls an aggregate of 5,918,894 common units. In addition, we have agreed to register for the sale, the common units held by CEPH. These registration rights allow CEPH to request registration of its common units and to include any of those common units in a registration of other securities by us. If CEPH were to sell a substantial portion of its common units, it could reduce the market price of our outstanding common units.

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

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.

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 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 and therefore result in a substantial reduction in the value of our common units.

Current law or our business may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. For example, in response to certain recent developments, members of Congress are considering substantive changes to the existing federal income tax laws that affect publicly traded partnerships. These changes could eliminate partnership tax treatment for certain publicly traded partnerships. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships and limited liability companies to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to unitholders would be reduced. Our limited liability company agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the initial quarterly distribution amount and the Target Distribution amount (as defined in our limited liability company agreement) will be adjusted to reflect the impact of that law on us.

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.

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

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

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

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

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

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

Because a common unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and he may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any 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.

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.

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.

CAUTIONARY NOTE REGARDING FORWARD–LOOKING STATEMENTS

This prospectus 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 natural gas prices;
- the discovery, estimation, development and replacement of oil and natural gas reserves;
- our business and financial strategy;
- our drilling locations;
- technology;
- our cash flow, liquidity and financial position;
- the impact from the of termination of the sharing arrangement before December 31, 2012;
- 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 weather and the occurrence of natural disasters such as fires, floods, hurricanes, earthquakes and other catastrophic events and natural disasters;
- governmental regulation of the oil and natural gas industry;
- developments in oil-producing and natural gas producing countries; and
- our strategic plans, objectives, expectations and intentions for future operations.

All of these types of statements, other than statements of historical fact included in this prospectus, are forward–looking statements. These forward–looking statements may be found in the “Summary,” “Risk Factors,” and other sections of this prospectus. In some cases, forward-looking statements can be identified by terminology such as “may,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “continue,” the negative of such terms or other comparable terminology.

The forward–looking statements contained in this prospectus 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 prospectus 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 prospectus. All forward–looking statements speak only as of the date of this prospectus. 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.

CHEROKEE BASIN ACQUISITIONS

Overview of Cherokee Basin

General

On April 23, 2007, we completed an acquisition of certain oil and gas properties and related assets located in Kansas and Oklahoma from EnergyQuest for approximately $111.2 million, subject to purchase price adjustments. The EnergyQuest assets consist of:

- certain coalbed methane properties with estimated proved reserves of 43 Bcfe;
- over 600 gross producing wells on approximately 96,000 gross acres; and
- support equipment, gathering pipelines and facilities.

In addition, we also purchased a 50% membership interest in five operating subsidiaries from a subsidiary of EnergyQuest for approximately $3.8 million, subject to purchase price adjustments. The EnergyQuest operating subsidiaries own:

- 31 wells located in Oklahoma;
- approximately 225 miles of gathering pipelines; and
- an operating company for the field support operations.

On July 25, 2007, we completed an acquisition of Amvest for approximately $240 million, subject to purchase price adjustments. Amvest owns oil and gas properties in the Cherokee Basin of Oklahoma. The Amvest assets consist of:

- certain oil and natural gas properties with estimated proved reserves of 71 Bcfe;
- approximately 370 producing wells generally with 100% working interest; and
- 13 year exclusive concession from the Osage Nation for coalbed methane and shale rights on approximately 560,000 net contiguous acres.

On September 21, 2007, we completed an acquisition of certain oil and gas properties and related assets located in the Cherokee Basin of Oklahoma from Newfield for approximately $128 million, subject to purchase price adjustments. The Newfield assets consist of:

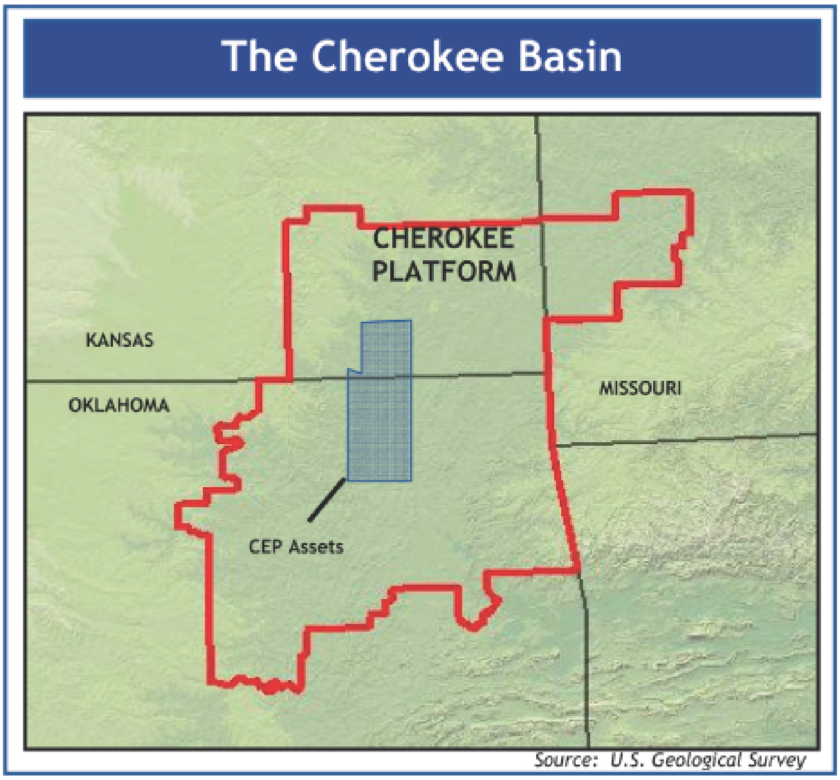
- certain coalbed methane properties with estimated proved reserves of 44 Bcfe;
- over 600 net producing wells with an average working interest of approximately 94% on approximately 80,000 net acres; and
- approximately 350 miles of pipeline gathering systems.

The Cherokee Basin is located in the Mid-Continent region in Kansas and Oklahoma. It is the eighth largest coalbed methane basin in the United States. Production of coalbed methane gas has been ongoing in the basin since the late 1980s. This basin's operating environment can be characterized as relatively less complex than other oil and natural gas basins in the United States. Given the relatively shallow 1,000 to 1,500 foot depths of the producing zones in the basin, wells can be drilled and completed at a cost of approximately $70,000 to $90,000 per well. Recompletions in the shallower, more recently targeted Mulky shale can be done at a cost of approximately $25,000 per well. Offsetting the low drilling costs are the relatively low reserves and low daily production rates per well.

We believe that this basin is well-suited for the E&P master limited partnership structure and our stated growth strategy. Production from this property is long-lived, and the drilling locations are low-risk with stable production. We believe this property has significant low-cost drilling and recompletion opportunities. We believe that the Cherokee Basin Acquisitions can also be effectively integrated into our properties portfolio. These acquisitions also allow us to expand our geographic footprint into other coalbed methane basins. Our current production of approximately 32,500 Mcfe per day places us as one of the top five producers in the basin.

Properties

Our properties in the Cherokee Basin are concentrated in Washington, Rogers, Tulsa, Nowata, Okmulgee and Osage Counties in Oklahoma and in Montgomery and Labetete Counties in Kansas.



Drilling Program

We have developed a first year drilling program to exploit known drilling locations and recompletion opportunities in the Cherokee Basin. We currently expect to drill approximately 170 net wells and 185 net recompletions during the first twelve months we own these properties. We estimate that $36 million in total capital will be spent during this time period, of which $13.5 million will consist of estimated maintenance capital expenditures.

Through the EnergyQuest acquisition, we acquired significant gathering system capacity, which we believe will provide us with an operational advantage in this basin. Our planned drilling program and available gathering system capacity provides us with the ability to offset decline rates from existing wells and to maintain production levels, which may permit us to maintain or increase our current distribution rate to our unitholders over time.

Table of Contents

Natural Gas Data

Proved Reserves

The following table reflects our internal estimates of net proved natural gas reserves based on SEC definitions for the Cherokee Basin Acquisitions at December, 31, 2006. The estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency other than the SEC in connection with this offering. The Standardized Measures shown in the table are not intended to represent the current market values of the estimated natural gas reserves in the Cherokee Basin.

Reserve data:	2006
Estimated net proved reserves:	
Natural gas and oil (Bcfe)	147.4
Proved developed reserves (Bcfe)	91.4
Proved undeveloped reserves (Bcfe)	56.0
Proved developed reserves as a percent of total reserves	62%
Standardized Measure (in millions)[(a)]	$244.6

(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. For a description of our derivative transactions, please read “Hedging Activity.”

Productive Wells

At December 31, 2006, there were 1,533 gross (1,405 net) operated producing wells in the Cherokee Basin properties we acquired in 2007 and 690 gross (280 net) non-operated wells in the Cherokee Basin properties we acquired in 2007. 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.

Developed and Undeveloped Acreage

At December 31, 2006, there were 150,000 gross developed acres and 66,920 net undeveloped acres in the Cherokee Basin properties we acquired in 2007. Developed acres are acres spaced or assigned to production wells or units. Undeveloped acres are acres on which wells have not been drilled or acres that have not been pooled with a productive well. 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.

Our ownership interest in the Cherokee Basin in Osage County, Oklahoma includes a 13 year exclusive concession from the Osage Nation for coalbed methane and shale rights on approximately 560,000 net contiguous acres. The concession agreement provides flexibility for leasing as drilling occurs within the concession area.

Leases

We have over 1,000 leases in the Cherokee Basin and a concession agreement with the Osage Nation in Osage County, Oklahoma which provides the exclusive right to lease on approximately 560,000 acres within the

Osage Nation. The typical lease agreement covering our properties provides for the payment of royalties to the mineral owner for all natural gas produced from any wells drilled on or pooled with the leased property. In the Cherokee Basin and adjoining areas for our operated properties, depending on the location of a particular well, the total lease burden is generally 20% corresponding to a 80% net revenue interest to us.

Under our lease agreements, our leases of E&P properties on which there is a productive well extends beyond their stated lease term and will not expire unless and until associated production falls below commercially viable levels. Such leases are said to be “held by production” and do not require us to make rental payments beyond the royalty amount stipulated by each lease. The area held by production from a particular well is typically the applicable spacing unit for such well as specified under state law.

Operations

We have entered into a transition services agreement with EnergyQuest to provide us with project management and operations services for the EnergyQuest Assets for a period of up to one year. EnergyQuest provides the services of a reasonably prudent oil and gas operator, management services, certain land administrative services, limited accounting services, insurance, and field operations services and we reimburse EnergyQuest for its actual costs and expenses for the operations of the properties in the Cherokee Basin. Certain management services, land administrative services, and accounting services are reimbursed at cost plus a ten percent surcharge. Throughout the term of the agreement, EnergyQuest acts under the direct supervision and oversight of CEPM under the management services agreement. All drilling programs, operations, development, and maintenance of the properties with respect to our assets in the field are conducted to the specifications developed by CEPM.

We operate all of the properties obtained in the Amvest Acquisition with company employees located at a field office in Skiatook, Oklahoma.

We have entered into a transition services agreement with Newfield to provide us with project management and operations services for the Newfield Assets for a period of up to three months. Newfield provides the services of a reasonably prudent oil and gas operator, management services, certain land administrative services, limited accounting services, insurance and field operations services and we reimburse Newfield for its actual costs and expenses for the operations of the properties in the Cherokee Basin. Throughout the term of the agreement, Newfield acts under the direct supervision and oversight of CEPM under the management services agreement. All drilling programs, operations, development and maintenance of the properties with respect to our assets in the field are conducted to the specifications developed by CEPM.

Field Operations

Our day-to-day operations related to the EnergyQuest Assets are currently conducted by field employees of EnergyQuest, under the transition services agreement. The field management team has extensive experience in the Cherokee Basin and has extensive experience with designing and implementing drilling programs in the geologic formations in Kansas and Oklahoma. 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 program and the management of the contractors responsible for the drilling and completion of these wells.

For the properties obtained in the Amvest Acquisition, our operations are handled by company employees who maintain and operate existing wells and infrastructure located in Osage County, Oklahoma. We have a field office located in Skiatook, Oklahoma. Our employees also coordinate our drilling and maintenance programs, manage contractors, handle regulatory and compliance matters and daily operations on the Amvest properties.

Our day-to-day operations related to Newfield Assets are currently conducted by field employees of Newfield, under the transition services agreement. These field employees are responsible for the operation of the existing production wells and related equipment, as well as interaction with the regulatory authorities with regard to permitting and compliance matters. In addition, they assist with the execution of the drilling program and the management of the contractors responsible for the drilling and completion of these wells.

Geology and Engineering

In addition to the services provided by EnergyQuest and Newfield under the transition services agreements, we are provided geologic and engineering assistance by CEPM, with access to CCG's in-house technical team including its 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 on an as needed basis 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 re-completions, optimizing compression and gathering systems and the like.

Land Administration

Our lease positions related to the EnergyQuest Assets and the Newfield Assets are currently managed by EnergyQuest and Newfield, respectively, under the transition services agreements with oversight provided by CEPM under the management services agreement, with assistance from outside contract landmen. The landmen provide assistance with management of our current lease positions, acquisitions for new leases, permitting for drilling and laying pipelines as well negotiating agreements with landowners for the use of their property. We administer, with assistance from CEPM under the management services agreement, the concession in Osage County, Oklahoma.

Revenue Accounting

Our revenue accounting function 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 assets in the Cherokee Basin, including the payment of invoices, calculation and payment of royalties, receives the revenues from gas sales and provides entries that are used to generate financial statements for us.

Marketing and Major Customers

We currently sell our oil and natural gas produced in the Cherokee Basin at the wellhead. Our oil production is primarily purchased by Sunoco Inc. while our natural gas production is primarily purchased by CIMA Energy Ltd, a gas marketing company, for the EnergyQuest Assets, by Scissortail Energy, LLC in Osage County, Oklahoma and by CIMA Energy Ltd. and CCG for the Newfield Assets. Our sales arrangement with CCG has been reviewed by the Conflicts Committee of our Board of Managers. Our realized pricing is primarily dependent upon the Oneok Gas Transportation LLC – Oklahoma ("ONEOK") and the Panhandle Eastern Pipe Line Co. – Texas, Oklahoma ("PEPL") Inside FERC Prices with respect to our properties in the Cherokee Basin. Our average net revenue interest in our operated Cherokee Basin properties is approximately 80% while our average net revenue interest in our non-operated Cherokee Basin properties is approximately 40%.

Hedging Activity

We expect to enter and have entered into hedging transactions with unaffiliated third parties with respect to natural gas prices to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in natural gas prices. In conjunction with the definitive purchase agreements to acquire the Cherokee Basin Acquisitions, we entered into derivative transactions to hedge certain of the future expected production associated with these acquisitions.

The following table summarizes, for the periods indicated, our hedges currently in place through December 31, 2010. Currently, we use fixed-price swaps and put options as our mechanisms for hedging commodity prices.

Our derivative positions accounted for as cash flow hedges at September 30, 2007 were:

Fixed Price Swaps

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu
2007	—	$ —	—	$ —	—	$ —	2,834,999	$ 8.47	2,834,999	$ 8.47
2008	2,612,501	$ 8.41	2,552,501	$ 8.39	2,565,001	$ 8.39	2,565,001	$ 8.39	10,295,004	$ 8.39
2009	1,837,500	$ 8.20	1,843,750	$ 8.20	1,850,000	$ 8.20	1,850,000	$ 8.20	7,381,250	$ 8 .20
2010	1,665,000	$ 7.96	1,677,500	$ 7.96	1,690,000	$ 7.96	1,690,000	$ 7.96	6,722,500	$ 7 .96
									27,233,753	

Our derivative positions accounted for as mark-to-market derivatives at September 30, 2007 were:

Put Options

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu
2007	—	$ —	—	$ —	—	$ —	110,000	$ 8.64	110,000	$ 8.64
2008	120,000	$ 9.05	120,000	$ 7.78	120,000	$ 7.78	120,000	$ 8.48	480,000	$ 8.27
2009	120,000	$ 8.83	120,000	$ 7.50	120,000	$ 7.50	40,000	$ 7.50	400,000	$ 7.90
									990,000	

We entered into derivative positions related to the acquisition of the Newfield Assets. These derivative positions will be accounted for as mark-to-market derivatives until designated as cash flow hedges.

Fixed Price Swaps

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu
2007	—	$ —	—	$ —	—	$ —	920,000	$ 8.21	920,000	$ 8.21
2008	455,000	$ 8.21	455,000	$ 8.21	460,000	$ 8.21	460,000	$ 8.21	1,830,000	$ 8.21
2009	450,000	$ 8.21	455,000	$ 8.21	460,000	$ 8.21	460,000	$ 8.21	1,825,000	$ 8.21
2010	450,000	$ 8.21	455,000	$ 8.21	460,000	$ 8.21	460,000	$ 8.21	1,825,000	$ 8.21
									6,400,000	

Swaptions

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu
2009	450,000	$ 8.69	455,000	$ 8.69	460,000	$ 8.69	460,000	$ 8.69	1,825,000	$ 8.69
									1,825,000	

Financing

We financed the purchase price of the EnergyQuest Acquisition with:

- the private placement of 2,207,684 common units and 90,376 Class E units at a price of $26.12 per unit and $25.84 per unit, respectively, which generated net proceeds to us of approximately $60 million; and
- funds available under our revolving credit facility.

We financed the purchase price of the Amvest Acquisition with:

- the private placement of 2,664,998 common units and 3,371,219 Class F units at an average price of $34.79 per unit, which generated net proceeds to us of approximately $210 million; and
- funds available under our revolving credit facility.

We financed the purchase price of the Newfield Acquisition with:

- the private placement of 2,470,592 common units at a price of $42.50 per unit, which generated net proceeds to us of approximately $105 million; and
- funds available under our revolving credit facility.

USE OF PROCEEDS

We will not receive any proceeds from the sale of common units offered under this prospectus. Any proceeds from the sale of common units offered under this prospectus will be received by the selling unitholders.

CAPITALIZATION

The following table sets forth our cash and cash equivalents and our capitalization as of September 30, 2007 on a historical basis.

We derived this table from, and it should be read together with and is qualified in its entirety by reference to, our historical and unaudited pro forma consolidated financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with "Summary—Constellation Energy Partners LLC" and "Use of Proceeds".

	As of September 30, 2007 Historical (In 000's)
Cash and cash equivalents	$ 19,519
Debt	
Reserve-based credit facility	147,000
Class D Interests[a]	7,333
Equity	
Members' equity	—
Common units held by public[b]	118,451
Common units held by CEPH[b]	139,050
Class A units held by CEPM	10,300
Common units held by private investors	247,202
Accumulated other comprehensive income[c]	12,741
Total equity	527,744
Total capitalization	$ 682,077

(a) Due to their contingently redeemable feature, the Class D interests will be treated as preferred units subject to contingent redemption in accordance with SEC Accounting Series Release No. 268, *Presentation in Financial Statements of Redeemable Preferred Stocks*.

(b) Reflects common units that have been issued under our long-term incentive plan.

(c) Includes $12.7 million of unrealized gains on our cash flow hedges.

Table of Contents

PRICE RANGE OF COMMON UNITS AND DISTRIBUTIONS

On November 23, 2007, we had 21,904,106 common units outstanding, beneficially held by approximately 2,500 holders. Our common units are traded on NYSE Arca under the symbol "CEP."

The following table sets forth, for the periods indicated, the high and low sales price ranges for our common units, as reported on NYSE Arca, and the amount, record date and payment date of the quarterly cash distributions paid per common unit. The last reported sales price of our common units on NYSE Arca on November 23, 2007 was $32.50 per common unit.

	Price ranges		Cash distribution history		
	High	Low	Per unit	Record date	Payment date
2006					
4th Quarter	$ 25.90	$ 21.75	$ 0.2111	February 7, 2007	February 14, 2007
2007					
1st Quarter	$ 35.93	$ 23.90	$ 0.4625	May 8, 2007	May 15, 2007
2nd Quarter	$ 41.25	$ 30.90	$ 0.4625	August 7, 2007	August 14, 2007
3rd Quarter	$ 50.74	$ 33.00	$ 0.5625	November 7, 2007	November 14, 2007
4th Quarter(1)	$ 42.73	$ 31.95	—(2)		

(1) Through November 23, 2007.

(2) The distribution with respect to the fourth quarter of 2007 has not been declared or paid.

HOW WE MAKE CASH DISTRIBUTIONS

Initial Quarterly Distributions

The amount of distributions paid under our cash distribution policy and the decision to make any distribution will be determined by our board of managers, taking into consideration the terms of our limited liability company agreement. We intend to distribute to the holders of common units and Class A units on a quarterly basis at least the IQD of $0.4625 per unit, or $1.85 per unit per year to the extent we have sufficient available cash after we establish appropriate reserves and pay fees and expenses, including payments to CEPM in reimbursement of costs and expenses it incurs on our behalf. Our current quarterly distribution rate is $0.5625 per unit, or $2.25 per unit on an annualized basis. Our IQD is intended to reflect the level of cash that we expect to be available for distribution per common unit and Class A unit each quarter from our productive assets. There is no guarantee we will pay the IQD in any quarter and we will be prohibited from making any distributions to unitholders if it would cause an event of default or an event of default is existing under our credit agreement. Our board of managers has adopted a policy that it will raise our quarterly cash distribution only when it believes that (i) we have sufficient reserves and liquidity for the proper conduct of our business, including the maintenance of our asset base, and (ii) we can maintain such an increased distribution level for a sustained period. While this is our current policy, our board of managers may alter such policy in the future when and if it determines such alteration to be appropriate.

Distributions of Available Cash

Overview

Our limited liability company agreement requires that, within 45 days after the end of each quarter we distribute all of our available cash to unitholders of record on the applicable record date.

Definition of Available Cash

We define available cash in the glossary, and it generally means, for each fiscal quarter, all cash on hand at the end of the quarter:

- less the amount of cash reserves established by our board of managers to:
  - provide for the proper conduct of our business (including reserves for future capital expenditures and credit needs);
  - comply with applicable law, any of our debt instruments, or other agreements; or
  - provide funds for distributions (1) to our unitholders for any one or more of the next four quarters or (2) in respect of our Class D interests or management incentive interests;
- plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our reserve-based credit facility or another arrangement and in all cases are used solely for working capital purposes or to pay distributions to unitholders.

Operating Surplus and Capital Surplus

General

All cash distributed to unitholders will be characterized as either “operating surplus” or “capital surplus.” Our limited liability company agreement requires that we distribute available cash from operating surplus differently than available cash from capital surplus.

Definition of Operating Surplus

We define operating surplus in the glossary, and for any period, it generally means:

- $20.0 million (as described below); *plus*
- all of our cash receipts after the closing of this offering, excluding cash from (1) borrowings that are not working capital borrowings, (2) sales of equity and debt securities and (3) sales or other dispositions of assets outside the ordinary course of business; *plus*
- working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; *plus*
- cash distributions paid on equity issued to finance all or a portion of the construction, replacement or improvement of a capital asset (such as equipment or reserves) during the period beginning on the date that we enter into a binding obligation to commence the construction, acquisition or improvement of a capital improvement or replacement of a capital asset and ending on the earlier to occur of the date the capital improvement or capital asset is placed into service or the date that it is abandoned or disposed of; *plus*
- if the right to receive distributions (other than distributions in liquidation) on the Class D interests terminates before December 31, 2012, the excess of the amount of the $8.0 million contribution by CHI for the Class D interests over the cumulative cash distributions paid on the Class D interests before such termination shall be included in operating surplus, such inclusion to occur over a series of quarters with the amount included in each quarter to be equal to the amount of the payment we make to the Trust in respect of the NPI for such quarter that would not have been paid but for termination of the sharing arrangement; *less*
- our operating expenditures (as defined below) after the closing of this offering; *less*
- the amount of cash reserves established by our board of managers to provide funds for future operating expenditures; *less*
- all working capital borrowings not repaid within twelve months after having been incurred.

As described above, operating surplus does not reflect actual cash on hand that is available for distribution to our unitholders. For example, it includes a provision that will enable us, if we choose, to distribute as operating surplus up to $20.0 million of cash we receive in the future from non-operating sources such as asset sales, issuances of securities and long-term borrowings that would otherwise be distributed as capital surplus. In addition, the effect of including, as described above, certain cash distributions on equity securities in operating surplus would be to increase operating surplus by the amount of any such cash distributions. As a result, we may also distribute as operating surplus up to the amount of any such cash distributions we receive from non-operating sources.

If a working capital borrowing, which increases operating surplus, is not repaid during the twelve-month period following the borrowing, it will be deemed repaid at the end of such period, thus decreasing operating surplus at such time. When such working capital borrowing is in fact repaid, it will not be treated as a reduction in operating surplus because operating surplus will have been previously reduced by the deemed repayment.

We define operating expenditures in the glossary, and it generally means all of our cash expenditures, including, but not limited to, taxes, reimbursement of expenses to CEPM for services under the management services agreement, payments made in the ordinary course of business under commodity hedge contracts, manager and officer compensation, repayment of working capital borrowings, debt service payments and estimated maintenance capital expenditures, *provided* that operating expenditures will not include:

- repayment of working capital borrowings deducted from operating surplus pursuant to the last bullet point of the definition of operating surplus when such repayment actually occurs;

- payments (including prepayments and prepayment penalties) of principal of and premium on indebtedness, other than working capital borrowings;
- expansion capital expenditures;
- actual maintenance capital expenditures;
- investment capital expenditures;
- payment of transaction expenses relating to interim capital transactions; or
- distributions to our members (including distributions in respect of our Class D interests and management incentive interests).

Capital Expenditures

For purposes of determining operating surplus, maintenance capital expenditures are those capital expenditures required to maintain, including over the long term, our asset base, and expansion capital expenditures are those capital expenditures that we expect will increase our asset base over the long term. Examples of maintenance capital expenditures include capital expenditures associated with the replacement of equipment and oil and natural gas reserves (including non-proved reserves attributable to undeveloped leasehold acreage), whether through the development, exploitation and production of an existing leasehold or the acquisition or development of a new oil or natural gas property. Maintenance capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued to finance all or any portion of a replacement asset during the period from such financing until the earlier to occur of the date any such replacement asset is placed into service or the date that it is abandoned or disposed of. Plugging and abandonment costs will also constitute maintenance capital expenditures. Capital expenditures made solely for investment purposes will not be considered maintenance capital expenditures.

Because our maintenance capital expenditures can be very large and irregular, the amount of our actual maintenance capital expenditures may differ substantially from period to period, which could cause similar fluctuations in the amounts of operating surplus, adjusted operating surplus and cash available for distribution to our unitholders if we subtracted actual maintenance capital expenditures from operating surplus. As a result, to eliminate the effect on operating surplus of these fluctuations, our limited liability company agreement requires that an estimate of the average quarterly maintenance capital expenditures (including estimated plugging and abandonment costs) necessary to maintain our asset base over the long term be subtracted from operating surplus each quarter as opposed to the actual amounts spent. The amount of estimated maintenance capital expenditures deducted from operating surplus is subject to review and change by our board of managers at least once a year, *provided* that any change is approved by our conflicts committee. The estimate is made at least annually and whenever an event occurs that is likely to result in a material adjustment to the amount of our maintenance capital expenditures, such as a major acquisition or the introduction of new governmental regulations that will impact our business. For purposes of calculating operating surplus, any adjustment to this estimate will be prospective only.

The use of estimated maintenance capital expenditures in calculating operating surplus has the following effects:

- it reduces the risk that maintenance capital expenditures in any one quarter will be large enough to render operating surplus less than the IQD to be paid on all the units for that quarter and subsequent quarters;
- it increases our ability to distribute as operating surplus cash we receive from non-operating sources;
- it is more difficult for us to raise our distribution above the IQD and pay management incentive distributions on our management incentive interests; and
- it reduces the likelihood that a large maintenance capital expenditure during the First MII Earnings Period or Later MII Earnings Period will prevent the payment of a management incentive distribution in

respect of the First MII Earnings Period or Later MII Earnings Period since the effect of an estimate is to spread the expected expense over several periods, thereby mitigating the effect of the actual payment of the expenditure on any single period.

Expansion capital expenditures are those capital expenditures that we expect will increase our asset base. Examples of expansion capital expenditures include the acquisition of reserves or equipment, the acquisition of new leasehold interest, or the development, exploitation and production of an existing leasehold interest, to the extent such expenditures are incurred to increase our asset base. Expansion capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued to finance all or any portion of such capital improvement during the period from such financing until the earlier to occur of the date any such capital improvement is placed into service or the date that it is abandoned or disposed of. Capital expenditures made solely for investment purposes will not be considered expansion capital expenditures.

As described above, none of actual maintenance capital expenditures, investment capital expenditures or expansion capital expenditures are subtracted from operating surplus. Because actual maintenance capital expenditures, investment capital expenditures and expansion capital expenditures include interest payments (and related fees) on debt incurred and distributions on equity issued to finance all of the portion of the construction, replacement or improvement of a capital asset (such as equipment or reserves) during the period from such financing until the earlier to occur of the date any such capital asset is placed into service or the date that it is abandoned or disposed of, such interest payments and equity distributions are also not subtracted from operating surplus (except, in the case of maintenance capital expenditures, to the extent such interest payments and distributions are included in estimated maintenance capital expenditures).

Investment capital expenditures are those capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures. Investment capital expenditures largely will consist of capital expenditures made for investment purposes. Examples of investment capital expenditures include traditional capital expenditures for investment purposes, such as purchases of securities, as well as other capital expenditures that might be made in lieu of such traditional investment capital expenditures, such as the acquisition of a capital asset for investment purposes or development of our undeveloped properties in excess of maintenance capital expenditures, but which are not expected to expand for more than the short term our asset base.

Capital expenditures that are made in part for maintenance capital purposes and in part for investment capital or expansion capital purposes will be allocated as maintenance capital expenditures, investment capital expenditures or expansion capital expenditure by our board of managers, based upon its good faith determination, subject to approval by our conflicts committee.

Definition of Capital Surplus

We also define capital surplus in the glossary, and it will generally be generated only by:

- borrowings other than working capital borrowings;
- sales of debt and equity securities; and
- sales or other disposition of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

Characterization of Cash Distributions

We treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since we began operations equals the operating surplus as of the most recent date of determination of available cash. We treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. We do not anticipate that we will make any distributions from capital surplus.

Distributions of Available Cash from Operating Surplus

We make distributions of available cash from operating surplus for any quarter in the following manner:

- *first*, 98% to the common unitholders, pro rata, and 2% to the holder(s) of our Class A units, pro rata, until we distribute for each outstanding unit an amount equal to the Target Distribution for that quarter; and
- *thereafter*, any amount distributed in respect of such quarter in excess of the Target Distribution per unit will be distributed 98% to the holders of the common units, pro rata, and 2% to the holder(s) of our Class A units until distributions become payable in respect of our management incentive interests as described in "—Management Incentive Interests" below.

The Class A units are entitled to 2% of all cash distributions from operating surplus, without any requirement for future capital contributions by the holders of such Class A units, even if we issue additional common units or other senior or subordinated equity securities in the future. The percentage interests shown above for the Class A units assume they have not been converted into common units. If the Class A units have been converted, the common units will receive the 2% of distributions originally allocated to the Class A units.

Management Incentive Interests

Management incentive interests represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution has been achieved and certain other tests have been met. CEPM currently holds the management incentive interests, which are evidenced by the Class C limited liability company interests, but may transfer these rights separately from its Class A units, subject to restrictions in our limited liability company agreement. The earliest that we could be required to make distributions in respect of the management incentive interests is after a period of 12 consecutive quarters after we pay per unit cash distributions from operating surplus to holders of Class A and common units in an amount equal or greater than the Target Distribution. The increase of our regular quarterly distribution from $0.4625 per unit to $0.5625 per unit on our outstanding common and Class A units will commence the First MII Earnings Period. An initial reserve of $0.1 million has been established to fund future distributions on the management incentive interests. We are not able to predict the amount of the distributions in respect of the management incentive interests.

Prior to the end of the First MII Earnings Period or Later MII Earnings Period, which are defined below, we will not pay any management incentive distributions. To the extent, however, that during the First MII Earnings Period or Later MII Earnings Period we distribute available cash from operating surplus in excess of the Target Distribution, our board of managers intends to cause us to reserve an amount for payment of the EP MID, which is defined below, earned during the First MII Earnings Period or Later MII Earnings Period, as the case may be, after such period ends. If during the First MII Earnings Period or Later MII Earnings Period we fail to satisfy a condition specified in the next paragraph, our board of managers will cause any such reserved amount to be released from that reserve and restored to available cash.

Payments to the holder of our management incentive interests are subject to the satisfaction of certain requirements. The first requirement is the 12-Quarter Test, which requires that for the 12 full, consecutive, non-overlapping calendar quarters that begin with the first calendar quarter in respect of which we pay per unit cash distributions from operating surplus to holders of Class A and common units in an amount equal to or greater than the Target Distribution (that is, our $0.4625 IQD plus $0.0694) (we refer to such 12-quarter period as the "First MII Earnings Period"):

- we pay cash distributions from operating surplus to holders of our outstanding Class A and common units in an amount that on average exceeds the Target Distribution on all of the outstanding Class A units and common units over the First MII Earnings Period;

- we generate adjusted operating surplus (which is summarized below and is defined in the glossary included as Appendix A) during the First MII Earnings Period that on average is in an amount at least equal to 100% of all distributions on the outstanding Class A and common units up to the Target Distribution plus 117.65% of all such distributions in excess of the Target Distribution; and
- we do not reduce the amount distributed per unit in respect of any such 12 quarters.

The second requirement is the 4-Quarter Test, which requires that for each of the last four full, consecutive, non-overlapping calendar quarters in the First MII Earnings Period:

- we pay cash distributions from operating surplus to the holders of our outstanding Class A and common units that exceed the Target Distribution on all of the outstanding Class A and common units;
- we generate adjusted operating surplus in an amount at least equal to 100% of all distributions on the outstanding Class A and common units up to the Target Distribution plus 117.65% of all such distributions in excess of the Target Distribution; and
- we do not reduce the amount distributed per unit in respect of any such four quarters.

If both the 12-Quarter Test and the 4-Quarter Test have been met, then: (i) we will make a one-time management incentive distribution (contemporaneously with the distribution paid in respect of the Class A and common units for the twelfth calendar quarter in the First MII Earnings Period) to the holder of our management incentive interests equal to 17.65% of the sum of the cumulative amounts, if any, by which quarterly cash distributions per unit part on the outstanding Class A and common units during the First MII Earnings Period exceeded the Target Distribution on all of the outstanding Class A and common units (we refer to this one-time management incentive distribution as an "EP MID"); and (ii) for each calendar quarter after the First MII Earnings Period, the holders of our Class A units and common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay for such quarter in excess of the Target Distribution.

If the 12-Quarter Test is not met and except as described below, management incentive distributions will not be payable in respect of the First MII Earnings Period and the holder of the management incentive interests will forfeit any and all rights to any management incentive distributions in respect of the First MII Earnings Period. An EP MID may become payable, however, with respect to a Later MII Earnings Period, if the 12-Quarter Test and the 4-Quarter Test are met in respect of such Later MII Earnings Period. A Later MII Earnings Period may begin with the first quarter following the quarter in which the 12-Quarter Test is not met, or, where we do not meet the 12-Quarter Test because we reduced our cash distribution in a particular quarter, the Later MII Earnings Period may begin with the quarter in which such reduction is made. If both tests are met with respect to a Later MII Earnings Period, then for each calendar quarter after the Later MII Earnings Period, the holders of the Class A units and common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay for such quarter in excess of the Target Distribution.

However, if (a) the 12-Quarter Test has been met in respect of the First MII Earnings Period or any Later MII Earnings Period, but not the 4-Quarter Test; (b) the 4-Quarter Test has been met in any period of four full, consecutive and non-overlapping quarters occurring after the end of the First MII Earnings Period or Later MII Earnings Period, as the case may be, up to three of which quarters can fall within the First MII Earnings Period or Later MII Earnings Period, as the case may be (we refer to such four-quarter period as the "MII 4-Quarter Earnings Period"); and (c) we have paid at least the IQD in each calendar quarter occurring between the end of the First MII Earnings Period or Later MII Earnings Period, as the case may be, and the beginning of the MII 4-Quarter Earnings Period:

- the holders of our Class A units and common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay in excess of the Target Distribution for each calendar quarter after the MII 4-Quarter Earnings Period; and

- the holder of our management incentive interests will receive an EP MID with respect to the First MII Earnings Period or Later MII Earnings Period, as the case may be.

Our board of managers has adopted a policy that it will raise our quarterly cash distribution only when it believes that (i) we have sufficient reserves and liquidity for the proper conduct of our business, including the maintenance of our asset base, and (ii) we can maintain such increased distribution level for a sustained period. While this is our current policy, our board of managers may alter such policy in the future when and if it determines such alteration to be appropriate.

Definition of Adjusted Operating Surplus

We define adjusted operating surplus in the glossary and for any period it generally means:

- operating surplus generated with respect to that period less any amounts described in the fifth bullet point under "—Definition of Operating Surplus" above; *less*
- any net increase in working capital borrowings with respect to that period (excluding any such borrowings to the extent the proceeds are distributed to the record holder of our Class D interests); *less*
- any net reduction in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; *plus*
- any net decrease in working capital borrowings with respect to that period; *plus*
- any net increase in cash reserves for operating expenditures made with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Adjusted operating surplus is intended to reflect the cash generated from our operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of the additional available cash from operating surplus between the unitholders and CEPM as the owner of our management incentive interests up to various distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our Class A unitholders and common unitholders and the holders of our management incentive interests in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Quarterly Distribution Level," until available cash from operating surplus we distribute reaches the next distribution level, if any. The percentage interests shown for the IQD are also applicable to quarterly distribution amounts that are less than the IQD. The percentage interests shown in the table below assume that the Class A units have not been converted into common units as described herein.

		Marginal Percentage Interest in Distributions		
	Quarterly Distribution Level	Class A Unitholders	Common Unitholders	Management Incentive Interests
IQD	$0.4625	2%	98%	0%
Target Distribution	above $0.4625 up to $0.5319	2%	98%	0%
Thereafter*	above $0.5319	2%	83%	15%

* Assumes the management incentive interests have met the 12-Quarter Test and the 4-Quarter Test. Until the 12-Quarter Test and the 4-Quarter Test are met and distributions in respect of the management incentive interests become payable, quarterly distributions in excess of the $0.5319 Target Distribution will be made 2% to the holder of the Class A units and 98% to the holders of common units, pro rata.

Distributions from Capital Surplus

How Distributions from Capital Surplus Are Made

We make distributions of available cash from capital surplus, if any, in the following manner:

- *first*, 2% to the holder of our Class A units and 98% to all common unitholders, pro rata, until we distribute for each common unit that was issued in our initial public offering an amount of available cash from capital surplus equal to the initial public offering price; and
- *thereafter*, we will make all distributions of available cash from capital surplus as if they were from operating surplus.

Effect of a Distribution from Capital Surplus

Our limited liability company agreement treats a distribution of capital surplus as the repayment of the initial common unit price from our initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per common unit is referred to as the "unrecovered capital" per initial common unit. Each time a distribution of capital surplus is made, the IQD and the Target Distribution will be reduced in the same proportion as the corresponding reduction in the unrecovered capital per common unit. Because distributions of capital surplus will reduce the IQD, after any of these distributions are made, it may be easier for CEPM to receive management incentive distributions. However, any distribution of capital surplus before the unrecovered capital per common unit is reduced to zero cannot be applied to the payment of the IQD.

Once we distribute capital surplus on a common unit in an amount equal to the unrecovered capital per common unit, we will reduce the IQD and the Target Distribution to zero. We will then make all future distributions from operating surplus, with 2% being distributed to the holder of our Class A units, 83% being distributed to our common unitholders, pro rata, and 15% being distributed to the holder of our management incentive interests. The percentage interests shown above for the Class A units assume they have not been converted into common units. If the Class A units have been converted, the common units will receive the 2% of distributions originally allocated to the Class A units.

Adjustment to the IQD and Target Distribution

In addition to adjusting the IQD and Target Distribution to reflect a distribution of capital surplus, if we combine our common units into fewer common units or subdivide our common units into a greater number of common units, we will proportionately adjust:

- the IQD;
- the Target Distribution; and
- the unrecovered capital per common unit.

For example, if a two-for-one split of the common units should occur, the Target Distribution and the unrecovered capital per common unit would each be reduced to 50% of its initial level. We will not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted by a court of competent jurisdiction, so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, we will reduce the IQD and the Target Distribution for each quarter by multiplying each by a fraction, the numerator of which is available cash for that quarter (after deducting our board of manager's estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation) and the denominator of which is the sum of available cash for that quarter plus our board of managers' estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.

Quarterly Cash Distributions on our Class D Interests

In order to address the risk of early termination, without the prior consent of board of managers, prior to December 31, 2012, of the sharing arrangement under the gas purchase contract pertaining to the calculation of amounts payable to the Trust for the NPI, and the potential reduction in our revenues resulting therefrom, at the closing of our initial public offering CHI contributed $8.0 million to us for all of our Class D interests. For each full calendar quarter during the period commencing January 1, 2007 and ending on December 31, 2012 that the sharing arrangement remains in effect, we will distribute to the holder of the Class D interests $333,333.33, 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 unitholders for that quarter. The Class D interests will be cancelled upon the payment of the final distribution of $333,333.41 to CHI for the quarter ending December 31, 2012, unless the special distribution right has been terminated earlier. Such special quarterly cash distributions will be made 45 days after the end of each calendar quarter.

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 and the remaining portion of the $8.0 million original contribution not so returned in special cash distributions will be retained by us to partially offset the reduction in our revenues resulting from termination of the sharing arrangement. In the case of such termination of the special distribution right, CHI will have the right only 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. See "—Distributions of Cash Upon Liquidation" below. If the sharing arrangement in respect of the Trust Wells is terminated during a quarter, the special distribution to CHI as the holder of our Class D interests will be prorated for that quarter based on the ratio of the number of days in such quarter prior to the effective date of such termination to 90. If we and any of the Trust, the trustee of the Trust or any subsequent holder of the NPI become involved in a dispute or proceeding in which such person asserts that prior to December 31, 2012 the sharing arrangement ceased to be applicable in calculating amounts payable in respect of production from the Trust Wells, special cash distributions in respect of the Class D interests for periods commencing at the inception of such dispute will be suspended, and such suspended amounts will only be paid to the holder of the Class D interests to the extent it is finally determined that the sharing arrangement remained applicable during some or all of the suspension period.

Distributions of Cash Upon Liquidation

General

If we dissolve in accordance with our limited liability company agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders, to CHI, the entity that contributed $8.0 million to us in exchange for the Class D interests, CEPH and CEPM in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

Manner of Adjustments for Gain

The manner of the adjustment for gain is set forth in our limited liability company agreement, and requires that we will allocate any gain to the unitholders and holders of the Class A units in the following manner:

- *first*, to the holders of common units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

- *second*, 2% to the holder of our Class A units and 98% to the common unitholders, pro rata, until the capital account for each common unit is equal to the sum of:

  (1) the unrecovered initial common unit price; and

  (2) the amount of the IQD for the quarter during which our liquidation occurs; and

- *third*, 100% to the holder of our Class D interests, until the capital account of the Class D interests equals, in the aggregate, the excess, if any, of (i) the $8.0 million capital contribution made to us by CHI at the closing of this offering for all of our Class D interests over (ii) the cumulative amount distributed as a special distribution to the holder of the Class D interests in accordance with the description under "Quarterly Cash Distributions On Our Class D interests" above;

- *fourth* 2% to the holder of our Class A units and 98% to the common unitholders, pro rata, until the capital account for each common unit is equal to the sum of:

  (1) the amount described above under the second bullet point of this paragraph; and

  (2) the excess of (I) over (II), where

    (I) equals the sum of the excess of the Target Distribution per common unit over the IQD for each quarter of our existence; and

    (II) equals the cumulative amount per common unit of any distributions of available cash from operating surplus in excess of the IQD per common unit that we distributed 98% to our common unitholders, pro rata, for each quarter of our existence; and

- *thereafter*, 2% to the holder of our Class A units, 83% to all common unitholders, pro rata, and 15% to the holder of our management incentive interests.

Manner of Adjustments for Losses

Upon our liquidation, we will generally allocate any loss 2% to the holder of the Class A units and 98% to the holders of the outstanding common units, pro rata.

Adjustments to Capital Accounts

We will make adjustments to capital accounts upon the issuance of additional common units. In doing so, we will allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the holder of the Class A units, the common unitholders, the holders of Class D interests and the holders of the management incentive interests in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional common units, we will allocate any later negative adjustments to the capital accounts resulting from the issuance of additional common units or upon our liquidation in a manner which results, to the extent possible, in the capital account balances of the holders of the management incentive interests equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made.

SELECTED HISTORICAL AND PRO FORMA CONSOLIDATED FINANCIAL DATA

Set forth below is our selected historical and unaudited pro forma consolidated financial data for the periods indicated. 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 Energy LLC ("Everlast") on June 13, 2005. We applied the purchase method of accounting to the separable assets and liabilities of the natural gas properties and equipment acquired from Everlast. The selected historical consolidated financial data of Everlast for the period from January 1, 2005 through June 12, 2005 and as of and for the years ended December 31, 2004 and 2003 have been derived from Everlast's audited historical financial statements. The historical financial data as of and for the year ended December 31, 2002 has been derived from unaudited financial data of Torch Energy, the predecessor to Everlast. The historical financial data of Constellation Energy Partners LLC as of December 31, 2006 and 2005, for the year ended December 31, 2006 and for the period from February 7, 2005 (inception) to December 31, 2005, have been derived from our audited historical consolidated financial statements. The historical consolidated financial data of Constellation Energy Partners LLC as of and for the nine months ended September 30, 2007 and 2006 have been derived from our unaudited historical consolidated financial statements. The selected unaudited pro forma consolidated financial data for the nine months ended September 30, 2007 and for the year ended December 31, 2006 have been derived from our unaudited pro forma consolidated financial statements and other financial information from EnergyQuest, Amvest and Newfield. For a description of the adjustments made in the unaudited pro forma consolidated financial statements, please read the notes to those financial statements.

These pro forma combined condensed financial statements show the pro forma effect of:

- the EnergyQuest Assets, Amvest Acquisition and the Newfield Assets.

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 GAAP. We explain this measure below and reconcile it to net income and net cash flow provided by operating activities, the most directly comparable financial measures calculated and presented in accordance with GAAP in "—Non-GAAP Financial Measure—Adjusted EBITDA" below.

You should read the following selected financial data in conjunction with our financial statements and the financial statements of Everlast and related notes appearing elsewhere in this prospectus. You should also read the pro forma information together with the unaudited pro forma consolidated financial statements and related notes included in this prospectus.

Prior to the Cherokee Basin Acquisitions, our only operations were in the Robinson's Bend Field, as were Everlast's. During each of the last three years, our properties in the Robinson's Bend Field were wholly-owned by us or Everlast. Our acquisition from Everlast resulted in a new basis for our properties in the Robinson's Bend Field for accounting purposes. In addition, new management, operating and accounting policies and accounting estimates were put into place after our acquisition from Everlast. Though the financial statements represent the operation of the same properties in the Robinson's Bend Field, due to these differences, the financial statements for the periods prior to and after our purchase of our properties in the Robinson's Bend Field 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 Robinson's Bend Field from Everlast may not be indicative of future results.

Table of Contents

	Predecessor				Successor					
	Torch Energy	Everlast Energy LLC			Constellation Energy Partners LLC					
									Pro Forma	
	For the year ended December 31, 2002	For the year ended December 31, 2003	For the year ended December 31, 2004	For the period from January 1, 2005 to June 12, 2005	For the period from February 7, 2005 (inception) to December 31, 2005[b]	For the year ended December 31, 2006	For the nine months ended September 30, 2006	For the nine months ended September 30, 2007	For the year ended December 31, 2006	For the nine months ended September 30, 2007
	Unaudited (In 000's)	As Restated[a]	As Restated[a] (In 000's)				Unaudited	Unaudited (In 000's)	Unaudited	Unaudited
Statement of Operations Data:										
Revenues:										
Oil and gas sales	$ 8,710	$ 22,320	$ 27,494	$ 12,882	$ 25,957	$ 36,917	$ 26,154	$ 50,033	$ 116,763	$ 95,493
Gain/(Loss) from mark-to-market activities	—	(3,664)	(9,107)	(15,313)	—	—	—	(2,766)	—	(2,766)
Total revenues	8,710	18,656	18,387	(2,431)	25,957	36,917	26,154	47,267	116,763	92,727
Operating Expenses:										
Lease operating expenses	7,763	4,428	5,270	2,769	4,175	7,234	5,321	9,822	26,998	20,472
Cost of sales	—	—	—	—	—	—	—	656	1,481	1,486
Production taxes	368	1,279	1,479	676	1,400	1,783	1,340	2,136	6,227	4,716
General and administrative	92	1,945	2,706	594	4,184	4,573	3,445	6,057	9,382	8,509
Depreciation, depletion and amortization	77	3,684	3,719	1,683	4,176	7,444	5,987	13,162	42,552	33,673
Accretion expense	—	73	86	46	78	141	106	211	583	431
(Gain) loss on asset sale	(4)	—	—	—	—	—	—	86	—	86
Total operating expenses	8,296	11,409	13,260	5,768	14,013	21,175	16,199	32,130	87,223	69,373
Other expenses (income):										
Interest expense	—	1,961	3,028	2,437	3	221	2	4,209	9,851	8,468
Interest (income)	—	—	—	—	—	(468)	(363)	(303)	(468)	(340)
Organization costs	—	299	—	—	—	—	—	—	—	—
Other income	—	—	—	—	—	—	—	(99)	(12)	(99)
Total other expenses (income)	—	2,260	3,028	2,437	3	(247)	(361)	3,807	9,371	8,029
Total expenses	8,296	13,669	16,288	8,205	14,016	20,928	15,838	35,937	96,594	77,402
Net income (loss)	$ 414	$ 4,987	$ 2,099	$ (10,636)	$ 11,941	$ 15,989	$ 10,316	$ 11,330	$ 20,169	$ 15,325
Basic earnings per unit					$ 1.05	$ 1.41	$ 0.91	$ 0.79	$ 0.90	$ 0.69
Basic units outstanding					11,320,300	11,320,300	11,320,300	14,289,600	22,351,128	22,351,128
Diluted earnings per unit					$ 1.05	$ 1.41	$ 0.91	$ 0.79	$ 0.90	$ 0.69
Diluted units outstanding					11,320,300	11,320,300	11,320,300	14,292,163	22,351,128	22,353,691
Other Financial Information (unaudited)										
Adjusted EBITDA	$ —	$ 10,193	$ 14,738	$ 8,795	$ 16,198	$ 23,025	$ 15,919	$ 32,946	$ 72,385	$ 61,894

(a) The financial statements of Everlast for 2003 and 2004 have been restated. Please read Note 2 to the historical consolidated financial statements included elsewhere in this prospectus.

(b) Until our acquisition of our properties in the Robinson's Bend Field from Everlast on June 13, 2005, we did not conduct any operations.

	Predecessor				Successor			
	Torch Energy	Everlast Energy LLC			Constellation Energy Partners LLC			
	For the year ended December 31, 2002	For the year ended December 31, 2003	For the year ended December 31, 2004	For the period from January 1, 2005 to June 12, 2005	For the period from February 7, 2005 (inception) to December 31, 2005[b]	For the year ended December 31, 2006	For the nine months ended September 30, 2006	For the nine months ended September 30, 2007
	Unaudited (In 000's)	As Restated[a]	As Restated[a] (In 000's)			(In 000's)	Unaudited	Unaudited
Balance Sheet Data (at period end):								
Cash and cash equivalents	$ —	$ 2,563	$ 2,012		$ 14,831	$ 7,485	$ 6,387	$ 19,519
Other current assets	39,014	1,812	4,562		6,097	18,602	27,242	27,174
Natural gas properties, net of accumulated depreciation, depletion and amortization	1,587	49,252	52,531		165,211	171,639	169,918	649,126
Other assets	—	590	1,579		—	5,971	16,400	20,495
Total assets	$ 40,601	$ 54,217	$ 60,684		$ 186,139	$ 203,697	$ 209,947	$ 716,314
Current liabilities	$ 43,812	$ 4,403	$ 4,482		$ 13,895	$ 9,007	$ 12,884	$ 23,538
Debt	—	26,000	67,500		63	22,000	—	147,000
Preferred units subject to mandatory redemption	—	16,752	—		—	—	—	—
Other long-term liabilities	—	2,671	3,314		3,014	2,730	3,160	10,699
Class D interests	—	—	—		—	8,000	—	7,333
Members equity:								
Common members equity (deficit)	(3,211)	4,391	(14,612)		169,167	148,847	179,853	515,003
Accumulated other comprehensive income	—	—	—		—	13,113	14,050	12,741
Total members' equity (deficit)	(3,211)	4,391	(14,612)		169,167	161,960	193,903	527,744
Total liabilities and members' equity (deficit)	$ 40,601	$ 54,217	$ 60,684		$ 186,139	$ 203,697	$ 209,947	$ 716,314
Cash Flow Data:								
Net cash provided by operating activities	$ 109	$ 9,773	$ 4,906	$ 6,639	$ 23,313	$ 14,067	$ 14,313	$ 33,260
Net cash used in investing activities	(109)	(47,832)	(6,997)	(4,203)	(147,237)	(25,429)	(22,694)	(499,749)
Net cash provided by (used in) financing activities	—	40,622	1,540	(2,500)	138,755	4,016	(63)	478,523
Development of natural gas properties	(109)	(2,040)	(5,680)	(4,000)	(8,286)	(13,224)	(10,071)	(17,679)

(a) The financial statements of Everlast for 2003 and 2004 have been restated. Please read Note 2 to the historical consolidated financial statements included elsewhere in this prospectus.
(b) Until our acquisition of our properties in the Robinson's Bend Field from Everlast on June 13, 2005, we did not conduct any operations.

Non–GAAP Financial Measure—Adjusted EBITDA

We use a variety of financial and operations measures to assess our performance, including a non-GAAP financial measure, Adjusted EBITDA. This measure is not calculated or presented in accordance with generally accepted accounting principles ("GAAP").

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;
- 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 to be used by our management to indicate (prior to the establishment of any 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 to 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.

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

	Predecessor		Successor					
	Everlast Energy LLC		Constellation Energy Partners LLC					
							Pro Forma	
	For the year ended December 31, 2004	For the period from January 1, 2005 to June 12, 2005	For the period from February 7, 2005 (inception) to December 31, 2005	For the year ended December 31, 2006	For the nine months ended September 30, 2006	For the nine months ended September 30, 2007	For the year ended December 31, 2006	For the nine months ended September 30, 2007
					Unaudited	Unaudited	Unaudited	Unaudited
	(In 000's)		(In 000's)					
Reconciliation of Net Income (Loss) to Adjusted EBITDA:								
Net income (loss)	$ 2,099	$ (10,636)	$ 11,941	$ 15,989	$ 10,316	$ 11,330	$ 20,169	$ 15,325
Adjusted by:								
Interest expense (income), net(a)	3,028	2,437	3	(247)	(361)	3,906	9,383	8,128
Depreciation, depletion and amortization	3,719	1,683	4,176	7,444	5,987	13,162	42,552	33,673
Accretion of asset retirement obligation	86	46	78	141	106	211	583	431
Loss on sale of asset	—	—	—	—	—	86	—	86
Unrealized loss (gain) on natural gas derivatives	(2,156)	15,265	—	—	(129)	4,229	—	4,229
Long-term incentive plan	—	—	—	—	—	22	—	22
Realized loss (gain) on cancelled natural gas derivatives	7,962	—	—	(302)	—	—	(302)	—
Adjusted EBITDA	$ 14,738	$ 8,795	$ 16,198	$ 23,025	$ 15,919	$ 32,946	$ 72,385	$ 61,894

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

Table of Contents

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

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

Percentage of total units beneficially owned is based on 22,351,128 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.

	Common Units Beneficially Owned(2)		Class A Units Beneficially Owned		Total Units Beneficially Owned(2)
Name of Beneficial Owner	Number	Percentage	Number	Percentage	Percentage
Constellation Energy Group, Inc.(1)	5,918,894	27.0%	447,022	100%	28.5%
Constellation Energy Partners Holdings, LLC(2)	5,918,894	27.0%	447,022	100%	28.5%
Constellation Energy Partners Management, LLC(3)	—	—	447,022	100%	2.0%
Lehman Brothers Holdings Inc.(4)	1,867,990	8.5%	—	—	8.4%
Richard H. Bachmann(5)	1,781	*	—	—	*
John R. Collins	—	—	—	—	—
Felix J. Dawson	—	—	—	—	—
Richard S. Langdon(5)	1,781	*	—	—	*
Angela A. Minas	—	—	—	—	—
John N. Seitz(5)	1,781	*	—	—	*
All managers and executive officers as a group (6 persons)(5)	5,343	*	—	—	*

(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 750 East Pratt Street, 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 111 Market Place, Baltimore, MD 21202.

(3) The address of Constellation Energy Partners Management, LLC is 111 Market Place, Baltimore, MD 21202.

(4) Lehman Brothers MLP Opportunity Fund LP ("LB MLP Fund") owns 1,867,990 common units. Lehman Brothers MLP Opportunity Associates LP ("LB MLP Assoc LP") is the general partner of LB MLP Fund. Lehman Brothers MLP Opportunity Associates LLC ("LB MLP Assoc LLC") is the general partner of LB MLP Assoc LP and is wholly-owned by Lehman Brothers Holdings Inc. ("LBHI"), a public reporting company. Accordingly, LBHI, LB MLP Assoc LLC and LB MLP Assoc LP may be deemed to be the beneficial owner of the Common Units owned by LB MLP Fund. The address of Lehman Brothers Holdings Inc. is 745 Seventh Avenue, New York, New York 10019.

(5) Includes unvested restricted common unit awards issued on September 14, 2007. These restricted common units will vest in full on March 1, 2008. 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, 2008.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

As of October 31, 2007:

- CEPM owns 447,022 Class A units, representing a 2% limited liability company interest in us, and all of the management incentive interests;
- CEPH owns 5,918,894 common units, representing an approximate 27% limited liability company interest in us; and
- CHI owns all of our Class D interests.

Distributions and Payments to CCG, CEPH, CEP Equity II LLC, CHI and CEPM

The following summarizes the distributions and payments that have been made or may be made by us to CCG, CEPH, CEP Equity II LLC, CHI and CEPM in connection with ongoing operation and any liquidation of Constellation Energy Partners LLC. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Initial Public Offering

Consideration received by CEPM and CEPH in our restructuring	CEPM and CEPH received 226,406 Class A units; 5,918,894 common units and the management incentive interests in conjunction with our initial public offering in November 2006. In addition, CHI contributed $8.0 million to us in exchange for all of the Class D interests. On October 30, 2006, we received $0.5 million from CEP Equity II LLC in exchange for the Floyd Shale Rights. As a result of our initial public offering, we distributed all our cash in excess of $3.9 million, including a cash pool balance, which was $12.4 million, to CCG. In November 2006, in connection with our initial public offering, we distributed $122.8 million to CEPH as a reimbursement for capital expenditures incurred by CCG prior to our initial public offering.

Operational Stage

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 a discussion of the management incentive interests, please read "How We Make Cash Distributions—Management Incentive Interests." Assuming we have sufficient available cash to pay the IQD on all of our outstanding units for four quarters, but no distributions in excess of the full IQD, CEPM would receive an annual distribution of

	approximately \$0.4 million on its Class A units and CEPH would receive an annual distribution of approximately \$12.2 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 the Trust for the NPI remains in effect, we will distribute to CHI, in respect of its Class D interests, \$333,333.33, 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 \$333,333.41 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. The most recent distribution of \$333,333 was paid to the holder of the Class D interests on November 14, 2007.
Payments to CEPM	Pursuant to our management services agreement with CEPM, we reimburse CEPM on a quarterly basis for costs incurred by it in performing services for us.
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.
Issuance of additional Class A units	Upon issuance of additional common units, a requisite number of additional Class A units will be issued such that the total ownership represented by the Class A units equals a two percent interest in the LLC.

Liquidation Stage

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. Please read “How We Make Cash Distributions—Distributions of Cash Upon Liquidation.”

Agreements with Constellation Affiliates

We and other Constellation affiliates have entered into various documents and agreements, including the contribution of $8.0 million to us by CHI and the conveyance by us to CEP Equity II, LLC of the Floyd Shale Rights. These agreements, including the management services agreement described below, were not the result of arm’s–length negotiations, and they, or any of the transactions that they provided for, may not be effected on terms at least as favorable to the parties to these agreements as they could have been obtained from unaffiliated third parties. All of the transaction expenses incurred in connection with these transactions were paid from the proceeds of our initial offering.

Class D Contribution by CHI

In order to address the risks of early termination, without the prior consent of our board of managers, of the sharing arrangement in respect of the calculation of amounts payable to the Trust for the NPI, and the potential reduction in our revenues resulting therefrom, at the closing of our initial public offering CHI contributed $8.0 million to us for all of our Class D interests. For each full calendar quarter during the period commencing January 1, 2007 and ending on December 31, 2012 that the sharing arrangement remains in effect, we will distribute to the holder of the Class D interests $333,333.33, 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 unitholders for that quarter. The Class D interests will be cancelled upon the payment of the final distribution of $333,333.41 to CHI for the quarter ending December 31, 2012, unless the special distribution right has been terminated earlier. 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 and the remaining portion of the $8.0 million original contribution not so returned in special cash distributions will be retained by us to partially offset the reduction in our revenues resulting from termination of the sharing arrangement in respect of the Trust. In the case of such termination of the special distribution right, CHI will have the right only 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 distribution right is terminated during a quarter, the special distribution to the holder of the Class D interests will be pro rated 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. The most recent distribution of $333,333 was paid to the holder of the Class D interests on November 14, 2007.

Sale of Floyd Shale Rights

On October 30, 2006, we sold to an affiliate of Constellation, CEP Equity II, LLC, an undivided mineral interest in our properties in the Robinson’s Bend Field for depths below 100 feet below the base of the lowest producing coal seam for $475,000. We refer to this mineral interest as the Floyd Shale Rights. The Floyd Shale Rights were not material to our business and no value was assigned to them in our historical financial statements included elsewhere in this prospectus. The Floyd Shale Rights did not fit our investment strategy, given the uncertainty of encountering commercial quantities of oil and natural gas.

Omnibus Agreement

At the closing of our initial public offering, we entered into the 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 Floyd Shale; 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 our initial public offering, *provided* (i) that such miscalculation relates to amount(s) payable no more than four years prior our initial public offering and (ii) the aggregate amount payable by CCG pursuant to this bullet point does not exceed $500,000.

Management Services Agreement

In connection with our initial public offering, we entered into a management services agreement with CEPM that governs our relationship with them regarding the following matters:

- CEPM's provision to us of certain supervisory and management services, including financial, acquisition and hedging and other risk management services;
- reimbursement of supervisory and management costs incurred by CEPM in performing services for us.

Financial, Acquisition and Other Services

Until December 31, 2007, we will be required under the management services agreement to use CEPM or its designee for legal, accounting, audit, tax, financial and risk management services. No other aspect of the management services agreement is exclusive. 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 provided that CEPM may receive added compensation for providing us with services as a result of the management incentive interests it holds. In connection with the acquisition services, we may acquire E&P properties with long-lived proved reserves in any of the following types of transactions:

- drop-downs, or acquisitions directly by us from CCG or its affiliates of properties previously acquired or developed by CCG or its affiliates;
- joint transactions in which CCG or its affiliates contemporaneously acquires from unaffiliated third parties E&P properties that do not fit our risk profile; and
- purchases made by us from unaffiliated third parties.

Competition

None of CEPM, Constellation, CCG or any of their affiliates are 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, E&P properties, in the future without any obligation to offer us the opportunity to purchase those assets. Please read "Conflicts of Interest and Fiduciary Duties."

Reimbursement of Costs

Subject to the arrangements relating to acquisition services described above, CEPM is 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 are deducted from cash available for distribution to our unitholders.

Review by Our Board of Managers

Except with respect to exclusive arrangements under the management services agreement through December 31, 2007, our board of managers has the right to evaluate CEPM's performance thereunder 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, willful 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 the initial term ending on December 31, 2007. 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.

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

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.

Cash Pool Arrangement

In February 2006, we entered into a cash pool arrangement with CCG. This cash pool arrangement was administered and managed by us. CCG could borrow from the pool at market interest rates. If we required cash, and CCG had an outstanding balance, CCG was required to immediately remit payment to us for the required cash amount. In November 2006, our participation in the cash arrangement was terminated and the outstanding receivable of $12.4 million from CCG was cancelled and CCG retained the funds. This was treated as a reduction of members' equity for accounting purposes.

Credit Support Fee Agreements

In connection with each of our acquisitions in the Cherokee Basin, Constellation entered into credit support agreements with us to provide guarantees to two banks that required credit support for certain financial derivatives.

- 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.
- 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 Paribas ("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 Paribas ("BNP"). This guarantee has 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 Paribas ("BNP").

We have paid Constellation $0.2 million for the credit support.

CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

Conflicts of Interest

Affiliates of Constellation own all of our Class A units, 5,918,894 common units, our management incentive interests and our Class D interests. In addition, upon the closing of our initial offering, we entered into a management services agreement with CEPM, a subsidiary of Constellation, and are dependent on CEPM for the management of our operations. Please read "Certain Relationships and Related Party Transactions—Agreements Governing the Transactions—Management Services Agreement." Conflicts of interest exist and may arise in the future as a result of the relationships between us and our unaffiliated unitholders and our board of managers and executive officers and Constellation and its affiliates, including CEPM and CEPH. These potential conflicts may relate to the divergent interests of these parties.

Whenever a conflict arises between Constellation and its affiliates, on the one hand, and us or any other unitholder, on the other hand, our board of managers will resolve that conflict. Our limited liability company agreement limits the remedies available to unitholders in the event a unitholder has a claim relating to conflicts of interest.

No breach of obligation will occur under our limited liability company agreement in respect of any conflict of interest if the resolution of the conflict is:

- approved by the conflicts committee of our board of managers, although our board of managers is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding units, excluding any common or Class A units owned by CEPM, CEPH or any of their affiliates although our board of managers is not obligated to seek such approval;
- on terms no less favorable to us than those generally provided to or available from unaffiliated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

We anticipate that our board of managers will submit for review and approval by our conflicts committee any acquisitions of properties or other assets that we propose to acquire from Constellation or any of its affiliates.

If our board of managers does not seek approval from the conflicts committee of our board of managers and our board determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the board of managers, including board members affected by the conflict of interest, acted in good faith, and in any proceeding brought by or on behalf of any member or the company, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our limited liability company agreement, our board of managers or its conflicts committee may consider any factors in good faith when resolving a conflict. When our limited liability company agreement requires someone to act in good faith, it requires that person to reasonably believe that he is acting in our best interests, unless the context otherwise requires.

Conflicts of interest could arise in the situations described below, among others.

Constellation and its affiliates may compete with us.

None of Constellation or any of its affiliates is restricted from competing with us. Constellation and its affiliates may acquire, invest in or dispose of E&P or other assets, including those that might be in direct competition with us.

Neither Constellation nor its affiliates have any obligation to offer us the opportunity to purchase or own interests in any assets.

We intend to rely on CEPM to provide us with opportunities for the acquisition of oil and natural gas reserves, however, neither Constellation nor its affiliates has any obligation to offer us the opportunity to purchase or own interests in any assets.

Affiliates of Constellation not only have the exclusive right to elect two members of our board of managers but also can assert great influence in the election of the other three members of our board of managers.

CEPM, as the holder of our Class A units will have the exclusive right to elect two members of our board of managers, and CEPH, as the largest holder of our common units, will be able to assert great influence in any vote of common unitholders, including the election of the three members of our board of managers that are elected by the common unitholders. In turn, our board of managers shall have the power to appoint our officers. Situations in which the interests of our management and Constellation and its affiliates may differ from interests of our unaffiliated unitholders include 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 management will use its reasonable discretion to establish and maintain cash reserves sufficient to fund our drilling program;
- our management team determines the timing and extent of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuances of additional membership interests and reserve adjustments, all of which will affect the amount of cash that we distribute to our unitholders;
- 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; and
- our board of managers is allowed to take into account the interest of parties other than us, such as Constellation and its affiliates, in resolving conflicts of interest, which has the effect of limiting the fiduciary duty to our unaffiliated unitholders.

Our executive officers and our Class A managers also serve as managers, directors, officers or employees of Constellation or its other affiliates as a result of which conflicts of interest exist and will arise in the future.

Our executive officers and our Class A managers are also managers, directors, officers or employees of Constellation or its affiliates (other than us). In making decisions in such person’s capacity as a manager, director, officer or employee of Constellation or such affiliate, such person may make a decision that favors the interests of Constellation or such affiliate over your interests and may be to our detriment, notwithstanding that in making decisions in such person’s capacity as our officer or manager such person is required to act in good faith and in accordance with the standards set forth in our limited liability company agreement. If in resolving a conflict of interest any of our executive officers and our Class A managers satisfies the applicable standards set forth in our limited liability company agreement for resolving a conflict of interest, you will not be able to assert that such resolution constituted a breach of fiduciary duty owed to us or to you by such executive officer or Class A manager.

We may compete for the time and effort of our managers and officers who are also managers, directors and officers of Constellation and its affiliates.

Constellation and its affiliates conduct business and activities of their own in which we have no economic interest. Certain of our managers and officers are employees of Constellation and serve as managers, directors and officers of Constellation and its affiliates. Our managers and officers are not required to work full time on our business and affairs and may devote significant time to the affairs of Constellation and its affiliates. There could be material competition for the time and effort of our managers and officers who provide services to Constellation and its affiliates.

Unitholders will have no right to enforce obligations of Constellation and its affiliates under agreements with us.

Any agreements, including the management services agreement, between us, on the one hand, and Constellation and its affiliates, on the other hand, will not grant to our unitholders any right to enforce the obligations of Constellation and its affiliates in our favor.

Contracts between us, on the one hand, and Constellation and its affiliates, on the other, will not be the result of arm's-length negotiations.

Neither our limited liability company agreement nor any of the other contracts or arrangements, including our management services agreement, between us and Constellation and its affiliates are or will be the result of arm's-length negotiations.

Fiduciary Duties

Our limited liability company agreement provides that our business and affairs shall be managed under the direction of our board of managers, which shall have the power to appoint our officers. Our limited liability company agreement further provides that the authority and function of our board of managers and officers shall be identical to the authority and functions of a board of directors and officers of a corporation organized under the Delaware General Corporation Law ("DGCL"). However, our managers and officers do not owe us the same duties that the directors and officers of a corporation organized under the DGCL would owe to that corporation. Rather, our limited liability company agreement provides that the fiduciary duties and obligations owed to us and to our members by our managers and officers is generally to act in good faith in the performance of their duties on our behalf. Our limited liability company agreement permits affiliates of our managers to invest or engage in other businesses or activities that compete with us. In addition, if our conflicts committee approves a transaction involving potential conflicts, or if a transaction is on terms generally available from unaffiliated third parties or an action is taken that is fair and reasonable to the company, unitholders will not be able to assert that such approval constituted a breach of fiduciary duties owed to them by our managers and officers.

We are unlike publicly traded partnerships whose business and affairs are managed by a general partner with fiduciary duties to the partnership. While CEPM provides legal, accounting, finance, tax, property management, engineering and other services to us pursuant to the management services agreement, subject to the oversight of our board of managers, we have no general partner with fiduciary duties to us. CEPM's duties to us are contractual in nature and arise solely under the management services agreement. As a consequence, none of Constellation, CEPM, CEPH, CCG or their affiliates owe to us a fiduciary duty similar to that owed by a general partner to its limited partners.

DESCRIPTION OF THE COMMON UNITS

The Common Units

The common units represent limited liability company interests in us. The holders of common units are entitled to participate in distributions and exercise the rights or privileges provided under our limited liability company agreement. For a description of the relative rights and preferences of holders of common units in and to distributions, please read this section and “How We Make Cash Distributions.” For a description of the rights and privileges of holders of common units under our limited liability company agreement, including voting rights, please read “The Limited Liability Company Agreement.”

Transfer Agent and Registrar

Computershare Trust Company, N.A. serves as registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units, except the following fees that will be paid by holders of common units:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a holder of a common unit; and
- other similar fees or charges.

There is no charge to unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their shareholders, managers, officers and employees against all claims and losses that may arise out of acts performed or omitted in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

The transfer agent may at any time resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor has been appointed and has accepted the appointment within 30 days after notice of the resignation or removal, we are authorized to act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our limited liability company agreement, each transferee of common units shall be admitted as a unitholder of our company with respect to the common units transferred when such transfer and admission is reflected on our books and records. Additionally, each transferee of common units:

- becomes the record holder of the common units;
- automatically agrees to be bound by the terms and conditions of, and is deemed to have executed our limited liability company agreement;
- represents that the transferee has the capacity, power and authority to enter into the limited liability company agreement;
- grants powers of attorney to our officers and any liquidator of our company as specified in the limited liability company agreement; and
- makes the consents and waivers contained in our limited liability company agreement.

A transferee will become a unitholder of our company for the transferred common units upon the recording of the name of the transferee on our books and records.

Until a common unit has been transferred on our books, we and the transfer agent, notwithstanding any notice to the contrary, may treat the record holder of the common unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

THE LIMITED LIABILITY COMPANY AGREEMENT

The following is a summary of the material provisions of our limited liability company agreement. Our limited liability company agreement is incorporated by reference as an exhibit to the registration statement of which this prospectus constitutes a part. We will provide prospective investors with a copy of the form of this agreement upon request at no charge.

We summarize the following provisions of our limited liability company agreement elsewhere in this prospectus:

- with regard to distributions of available cash, please read “How We Make Cash Distributions.”
- with regard to the transfer of common units, please read “Description of the Common Units—Transfer of Common Units;” and
- with regard to allocations of taxable income and taxable loss, please read “Material Tax Consequences.”

Organization

Our company was formed in February 2005 and will remain in existence until dissolved in accordance with our limited liability company agreement.

Purpose

Under our limited liability company agreement, we are permitted to engage, directly or indirectly, in any activity that our board of managers approves and that a limited liability company organized under Delaware law lawfully may conduct; *provided*, that our board of managers shall not cause us to engage, directly or indirectly, in any business activities that it determines would cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes.

Although our board of managers has the ability to cause us and our operating subsidiaries to engage in activities other than the acquisition, development and exploitation, of oil and natural gas properties and related midstream assets, our board of managers has no current plans to do so. Our board of managers is authorized in general to perform all acts it deems to be necessary or appropriate to carry out our purposes and to conduct our business.

Fiduciary Duties

Our limited liability company agreement provides that the fiduciary duties and obligations owed to us and to our members by our managers and officers is generally limited to their acting in good faith in the performance of their duties on our behalf. For a description of fiduciary duties, please read “Conflicts of Interest and Fiduciary Duties.”

Agreement to be Bound by Limited Liability Company Agreement; Power of Attorney

By purchasing a common unit in us, you will be admitted as a member of our company and will be deemed to have agreed to be bound by the terms of our limited liability company agreement. Pursuant to this agreement, each holder of common units and each person who acquires a common unit from a holder of common units grants to our board of managers (and, if appointed, a liquidator) a power of attorney to, among other things, execute and file documents required for our qualification, continuance or dissolution. The power of attorney also grants our board of managers the authority to make certain amendments to, and to make consents and waivers under and in accordance with, our limited liability company agreement.

Capital Contributions

Unitholders (including holders of common units) are not obligated to make additional capital contributions, except as described below under “—Limited Liability.”

Limited Liability

Unlawful Distributions

The Delaware Limited Liability Company Act (the "Delaware Act") provides that any unitholder who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the company for the amount of the distribution for three years. Under the Delaware Act, a limited liability company may not make a distribution to any unitholder if, after the distribution, all liabilities of the company, other than liabilities to unitholders on account of their limited liability company interests and liabilities for which the recourse of creditors is limited to specific property of the company, would exceed the fair value of the assets of the company. For the purpose of determining the fair value of the assets of a company, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the company only to the extent that the fair value of that property exceeds the nonrecourse liability. Under the Delaware Act, an assignee who becomes a substituted unitholder of a company is liable for the obligations of his assignor to make contributions to the company, except the assignee is not obligated for liabilities unknown to him at the time he became a unitholder and that could not be ascertained from the limited liability company agreement.

Failure to Comply with the Limited Liability Provisions of Jurisdictions in Which We Do Business

Our subsidiaries may be deemed to conduct business in Alabama, Kansas, Maryland, Oklahoma and Texas. We may decide to conduct business in other states, and maintenance of limited liability for us, as a member of our operating subsidiaries, may require compliance with legal requirements in the jurisdictions in which the operating subsidiaries conduct business, including qualifying our subsidiaries to do business there. Limitations on the liability of unitholders for the obligations of a limited liability company have not been clearly established in many jurisdictions. We will operate in a manner that our board of managers considers reasonable and necessary or appropriate to preserve the limited liability of our unitholders.

Voting Rights

Holders of our common units and our Class A units, have voting rights on most matters. The following matters require the unitholder vote specified below:

Election of members of the board of managers	Our board of managers consists of five members, as required by our limited liability company agreement. Except as set forth below, at the first annual meeting of our unitholders following our initial public offering, Class A unitholders, voting as a single class, will elect two managers and the holders of our common units, voting together as a single class, will elect the remaining three managers. Please read "—Election of Members of Our Board of Managers," "—Removal of Members of Our Board of Managers" and "—Elimination of Special Voting Rights of Class A Units."
Issuance of additional securities including common units	No approval right.
Amendment of the limited liability company agreement	Certain amendments may be made by our board of managers without unitholder approval. Other amendments generally require the approval of both a common unit majority and Class A unit majority. Please read "—Amendment of Our Limited Liability Company Agreement."

Merger of our company or the sale of all or substantially all of our assets	Common unit majority and Class A unit majority. Please read "—Merger, Sale or Other Disposition of Assets."
Dissolution of our company	Common unit majority and Class A unit majority. Please read "—Termination and Dissolution."

Matters requiring the approval of a "common unit majority" require the approval of at least a majority of the outstanding common units voting together as a single class. In addition, matters requiring the approval of a "Class A unit majority" require the approval of at least a majority of the outstanding Class A units voting together as a single class.

Issuance of Additional Securities

Our limited liability company agreement authorizes us to issue an unlimited number of additional securities and authorizes us to buy securities for the consideration and on the terms and conditions determined by our board of managers without the approval of our unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units or other equity securities. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units, Class A units and management incentive interests in our distributions of available cash. Also, the issuance of additional common units or other equity securities may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our limited liability company agreement, we may also issue additional securities that, as determined by our board of managers, may have special voting or other rights to which the units are not entitled.

The holders of units will not have preemptive or preferential rights to acquire additional units or other securities.

Election of Members of Our Board of Managers

At our first annual meeting of the holders of our Class A units and our common unitholders following our initial public offering:

- two members of our board of managers will be elected by CEPM, as the holder of all of our Class A units; and
- three members of our board of managers will be elected by our common unitholders.

The board of managers will be subject to re-election on an annual basis in this manner at our annual meeting of the holders of our Class A units and our common unitholders.

Removal of Members of Our Board of Managers

Any manager elected by the holder of our Class A units may be removed, with or without cause, by the holders of 66 $^2/_3$% of the outstanding Class A units then entitled to vote at an election of managers. Any manager elected by the holders of our common units may be removed, with or without cause, by the holders of at least a majority of the outstanding common units then entitled to vote at an election of managers.

Increase in the Size of Our Board of Managers

The size of our board of managers may increase only with the approval of the holders of 66 $^2/_3$% outstanding Class A units. If the size of our board of managers is so increased, the vacancy created thereby shall be filled by a person appointed by our board of managers or a nominee approved by a majority vote of our common unitholders, unless such vacancy is specified by an amendment to our limited liability company agreement as a vacancy to be filled by our Class A unitholders, in which case such vacancy shall be filled by a person approved by our Class A unitholders.

Elimination of Special Voting Rights of Class A Units

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, subject to the matters described under "—Election of Members of Our Board of Managers—Increase in the Size of Our Board of Managers" above. This right can be eliminated only upon a proposal submitted by or with the consent of our board of managers and the vote of the holders of not less than 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.

Amendment of Our Limited Liability Company Agreement

General

Amendments to our limited liability company agreement may be proposed only by or with the consent of our board of managers. To adopt a proposed amendment, other than the amendments discussed below, our board of managers is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of our unitholders to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a common unit majority and a Class A unit majority.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any unitholder without its consent, unless approved by at least a majority of the type or class of member interests so affected;
- provide that we are not dissolved upon an election to dissolve our company by our board of managers that is approved by a common unit majority and a Class A unit majority;
- entitle members holding common units and/or Class A units to more or less than one vote per unit;
- prohibit the holders of Class A units from acting without a meeting;
- change the procedures for notice to members of business to be brought before a meeting and nominations to board of managers;
- require some percentage other than a majority of votes cast affirmatively or negatively by members holding units for approval of matters submitted for a member vote;
- allow the calling of a special meeting by other than a majority of the board of managers;
- change the term of existence of our company;
- give any person the right to dissolve our company other than our board of managers' right to dissolve our company with the approval of a common unit majority and a Class A unit majority; or
- enlarge the size of our board of managers without the approval of the holders of 66 2/3% of our Class A units.

The provision of our limited liability company agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 75% of the outstanding common units, voting together as a single class, and 75% of the outstanding Class A units, voting together as a single class.

No Unitholder Approval

Our board of managers may generally make amendments to our limited liability company agreement without unitholder approval to reflect:

- a change in our name, the location of our principal place of our business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of members in accordance with our limited liability company agreement;
- a change that our board of managers determines to be necessary or appropriate for us to qualify or continue our qualification as a company in which our members have limited liability under the laws of any state or to ensure that neither we, our operating subsidiaries nor any of its subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;
- the merger of our company or any of its subsidiaries into, or the conveyance of all of our assets to, a newly formed entity if the sole purpose of that merger or conveyance is to effect a mere change in our legal form into another limited liability entity;
- an amendment that is necessary, in the opinion of our counsel, to prevent us, members of our board, or our officers, agents or trustees from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or “plan asset” regulations adopted under the Employee Retirement Income Security Act of 1974 (“ERISA”) whether or not substantially similar to plan asset regulations currently applied or proposed;
- an amendment that our board of managers determines to be necessary or appropriate for the authorization of additional securities or rights to acquire securities;
- any amendment expressly permitted in our limited liability company agreement to be made by our board of managers acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our limited liability company agreement;
- any amendment that our board of managers determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our limited liability company agreement;
- a change in our fiscal year or taxable year and related changes;
- a merger, conversion or conveyance effected in accordance with the limited liability company agreement; and
- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our board of managers may make amendments to our limited liability company agreement without unitholder approval if our board of managers determines that those amendments:

- do not adversely affect the unitholders (including any particular class of unitholders as compared to other classes of unitholders) in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;

- are necessary or appropriate to facilitate the trading of common units or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the common units are or will be listed for trading, compliance with any of which our board of managers deems to be in the best interests of us and our common unitholders;
- are necessary or appropriate for any action taken by our board of managers relating to splits or combinations of units under the provisions of our limited liability company agreement; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our limited liability company agreement or are otherwise contemplated by our limited liability company agreement.

Opinion of Counsel and Unitholder Approval

Our board of managers will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to our unitholders or result in our being treated as an entity for federal income tax purposes if one of the amendments described above under "—No Unitholder Approval" should occur. No other amendments to our limited liability company agreement will become effective without the approval of holders of at least 90% of the common units and Class A units unless we obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any unitholder of our company.

Any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any amendment that reduces the voting percentage required to take any action is required to be approved by the affirmative vote of unitholders whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced.

Merger, Sale or Other Disposition of Assets; Conversion

Our board of managers is generally prohibited, without the prior approval of a common unit majority and a Class A unit majority from causing us to, among other things, sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination, or approving on our behalf the sale, exchange or other disposition of all or substantially all of the assets of our subsidiaries, *provided* that our board of managers may mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our board of managers may also sell all or substantially all of our assets under a foreclosure or other realization upon the encumbrances above without that approval.

If the conditions specified in the limited liability company agreement are satisfied, our board of managers may merge our company or any of its subsidiaries into, or convey all of our assets to, a newly formed entity if the sole purpose of that merger or conveyance is to effect a mere change in our legal form into another limited liability entity. Additionally, the Company may convert into any "other entity" as defined in the Delaware Limited Liability Company Act, whether such entity is formed under the laws of the State of Delaware or any other state in the United States of America. Our unitholders are not entitled to dissenters' rights of appraisal under the limited liability company agreement or applicable Delaware law in the event of a merger or consolidation, a sale of all or substantially all of our assets or any other transaction or event.

Termination and Dissolution

We will continue as a company until terminated under our limited liability company agreement. We will dissolve upon: (1) the election of our board of managers to dissolve us, if approved by a common unit majority and a Class A unit majority; (2) the sale, exchange or other disposition of all or substantially all of the assets and properties of our company and our subsidiaries; or (3) the entry of a decree of judicial dissolution of our company.

Table of Contents

Liquidation and Distribution of Proceeds

Upon our dissolution, the liquidator authorized to wind up our affairs will, acting with all of the powers of our board of managers that the liquidator deems necessary or desirable in its judgment, liquidate our assets and apply the proceeds of the liquidation as provided in "How We Make Cash Distributions—Distributions of Cash Upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to unitholders in kind if it determines that a sale would be impractical or would cause undue loss to our unitholders.

Anti-Takeover Provisions

Our limited liability company agreement contains specific provisions that are intended to discourage a person or group from attempting to take control of our company without the approval of our board of managers. Specifically, our limited liability company agreement provides that we will elect to have Section 203 of the DGCL apply to transactions in which an interested common unitholder (as described below) seeks to enter into a merger or business combination with us. Under this provision, such a holder will not be permitted to enter into a merger or business combination with us unless:

- prior to such time, our board of managers approved either the business combination or the transaction that resulted in the common unitholder's becoming an interested common unitholder;
- upon consummation of the transaction that resulted in the common unitholder becoming an interested common unitholder, the interested common unitholder owned at least 85% of our outstanding common units at the time the transaction commenced, excluding for purposes of determining the number of common units outstanding those common units owned:
- by persons who are managers and also officers; and
- by employee common unit plans in which employee participants do not have the right to determine confidentially whether common units held subject to the plan will be tendered in a tender or exchange offer; or
- at or subsequent to such time the business combination is approved by our board of managers and authorized at an annual or special meeting of our common unitholders, and not by written consent, by the affirmative vote of the holders of at least 66 $^{2}/_{3}$% of our outstanding voting common units that are not owned by the interested common unitholder.

Section 203 defines "business combination" to include:

- any merger or consolidation involving the company and the interested common unitholder;
- any sale, transfer, pledge or other disposition of 10% or more of the assets of the company involving the interested common unitholder;
- subject to certain exceptions, any transaction that results in the issuance or transfer by the company of any common units of the company to the interested common unitholder;
- any transaction involving the company that has the effect of increasing the proportionate share of the units of any class or series of the company beneficially owned by the interested common unitholder; or
- the receipt by the interested common unitholder of the benefit of any loans, advances, guarantees, pledges or other financial benefits provided by or through the company.

In general, by reference to Section 203, an "interested common unitholder" is any person or entity, other than Constellation, CEPM, their affiliates or transferees, that beneficially owns (or within three years did own) 15% or more of the outstanding common units of the company and any entity or person affiliated with or controlling or controlled by such entity or person.

The existence of this provision would be expected to have an anti-takeover effect with respect to transactions not approved in advance by our board of managers, including discouraging attempts that might result in a premium over the market price for common units held by common unitholders.

Our limited liability agreement also 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.

Limited Call Right

If at any time any person owns more than 80% of the then-issued and outstanding common units, it will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons as of a record date to be selected by our board of managers, on at least 10 days but not more than 60 days notice. The common unitholders are not entitled to dissenters' rights of appraisal under the limited liability company agreement or applicable Delaware law if this limited call right is exercised. The purchase price in the event of this purchase is the greater of:

- the highest cash price paid by such person for any common units purchased within the 90 days preceding the date on which such person first mails notice of its election to purchase the remaining common units; and
- the closing market price of the common units as of the date three days before the date the notice is mailed.

As a result of this limited call right, a holder of common units may have his limited liability company interests purchased at an undesirable time or price. Please read "Risk Factors—Risks Related to Our Structure." The tax consequences to a common unitholder of the exercise of this call right are the same as a sale by that common unitholder of his common units in the market. Please read "Material Tax Consequences—Disposition of Units."

Meetings; Voting

All notices of meetings of unitholders shall be sent or otherwise given in accordance with Sections 11.4 and 14.1 of our limited liability company agreement not less than 10 days nor more than 60 days before the date of the meeting. The notice shall specify the place, date and hour of the meeting and (i) in the case of a special meeting, the general nature of the business to be transacted (no business other than that specified in the notice may be transacted) or (ii) in the case of the annual meeting, those matters which the board of managers, at the time of giving the notice, intends to present for action by the unitholders (but any proper matter may be presented at the meeting for such action). The notice of any meeting at which managers are to be elected shall include the name of any nominee or nominees who, at the time of the notice, the board of managers intends to present for election. Any previously scheduled meeting of the unitholders may be postponed, and any special meeting of the unitholders may be cancelled, by resolution of the board of managers upon public notice given prior to the date previously scheduled for such meeting of unitholders.

Units that are owned by an assignee who is a record holder, but who has not yet been admitted as a member, shall be voted at the written direction of the record holder by a proxy designated by our board of managers. Absent direction of this kind, the units will not be voted, except that units held by us on behalf of non-citizen assignees shall be voted in the same ratios as the votes of unitholders on other units are cast.

Any action required or permitted to be taken by our common unitholders must be effected at a duly called annual or special meeting of unitholders and may not be effected by any consent in writing by such common unitholders.

Special meetings of the unitholders may only be called by a majority of our board of managers. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units for which a meeting has been called represented in person or by proxy shall constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum shall be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional units having special voting rights could be issued. Please read “—Issuance of Additional Securities.” Units held in nominee or street name accounts will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and its nominee provides otherwise.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of units under our limited liability company agreement will be delivered to the record holder by us or by the transfer agent.

Our limited liability agreement also 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.

Non-Citizen Assignees; Redemption

If we or any of our subsidiaries are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our board of managers, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any unitholder or assignee, we may redeem, upon 30 days’ advance notice, the units held by the unitholder or assignee at their current market price. To avoid any cancellation or forfeiture, our board of managers may require each unitholder or assignee to furnish information about his nationality, citizenship or related status. If a unitholder or assignee fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our board of managers determines after receipt of the information that the unitholder or assignee is not an eligible citizen, the unitholder or assignee may be treated as a non-citizen assignee. In addition to other limitations on the rights of an assignee who is not a substituted unitholder, a non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation.

Indemnification

Under our limited liability company agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by law from and against all losses, claims, damages or similar events any person who is or was our manager or officer, or while serving as our manager or officer, is or was serving as a tax matters member or, at our request, as a manager, officer, tax matters member, employee, partner, fiduciary or trustee of us or any of our subsidiaries. Additionally, we shall indemnify to the fullest extent permitted by law and authorized by our board of managers, from and against all losses, claims, damages or similar events any person is or was an employee or agent (other than an officer) of our company.

Any indemnification under our limited liability company agreement will only be out of our assets. We are authorized to purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our limited liability company agreement.

Books and Reports

We are required to keep appropriate books of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available to record holders of units, within 120 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent public accountants. Except for our fourth quarter, we will also furnish or make available summary financial information within 90 days after the close of each quarter.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of unitholders can be avoided. Our ability to furnish this summary information to unitholders will depend on the cooperation of unitholders in supplying us with specific information. Every unitholder will receive information to assist him in determining his federal and state tax liability and filing his federal and state income tax returns, regardless of whether he supplies us with information.

Right To Inspect Our Books and Records

Our limited liability company agreement provides that a unitholder can, for a purpose reasonably related to his interest as a unitholder, upon reasonable demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each unitholder;
- a copy of our tax returns;
- information as to the amount of cash, and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each unitholder and the date on which each became a unitholder;
- copies of our limited liability company agreement, the certificate of formation of the company, related amendments and powers of attorney under which they have been executed;
- information regarding the status of our business and financial condition; and
- any other information regarding our affairs as is just and reasonable.

Our board of managers may, and intends to, keep confidential from our unitholders information that it believes to be in the nature of trade secrets or other information, the disclosure of which our board of managers believes in good faith is not in our best interests, information that could damage our company or our business, or information that we are required by law or by agreements with a third-party to keep confidential.

Registration Rights

We have agreed to register for sale under the Securities Act and applicable state securities laws any common units or other of our securities held by CEPM, CEPH or any of their affiliates if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any termination of the special voting rights of the holders of our Class A units. We have also agreed to include any of our securities held by CEPM, CEPH or their affiliates in any registration statement that we file to offer our securities for cash, except an offering relating solely to an employee benefit plan, for the same period. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and commissions.

MATERIAL TAX CONSEQUENCES

This section is a discussion of the material tax consequences that may be relevant to prospective common unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, is the opinion of Andrews Kurth LLP, counsel to us, insofar as it relates to matters of United States federal income tax law and legal conclusions with respect to those matters. This section is based on current provisions of the Internal Revenue Code, existing and proposed regulations and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to "us" or "we" are references to Constellation Energy Partners LLC and our limited liability company operating subsidiaries.

This section does not address all federal income tax matters that affect us or common unitholders. Furthermore, this section focuses on common unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, trusts, non-resident aliens or other common unitholders subject to specialized tax treatment, such as tax-exempt institutions, foreign persons, individual retirement accounts (IRAs), employee benefit plans, real estate investment trusts (REITs) or mutual funds. Accordingly, we urge each prospective holder of common units to consult, and depend on, his own tax advisor in analyzing the federal, state, local and foreign tax consequences particular to him of the ownership or disposition of our units.

No ruling has been or will be requested from the IRS regarding any matter that affects us or prospective common unitholders. Instead, we rely on opinions and advice of Andrews Kurth LLP. Unlike a ruling, an opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made in this discussion may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for our units and the prices at which our units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our common unitholders and thus will be borne directly by our common unitholders. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

All statements regarding matters of law and legal conclusions set forth below, unless otherwise noted, are the opinion of Andrews Kurth LLP and are based on the accuracy of the representations made by us. Statements of fact do not represent opinions of Andrews Kurth LLP.

For the reasons described below, Andrews Kurth LLP has not rendered an opinion with respect to the following specific federal income tax issues:

- the treatment of a common unitholder whose units are loaned to a short seller to cover a short sale of units (please read "—Tax Consequences of Unit Ownership—Treatment of Short Sales");
- whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury regulations (please read "—Disposition of Units—Allocations Between Transferors and Transferees"); and
- whether our method for depreciating Section 743 adjustments is sustainable in certain cases (please read "—Tax Consequences of Unit Ownership—Section 754 Election" and "—Uniformity of Units").

Partnership Status

Except as discussed in the following paragraph, a limited liability company that has more than one member and that has not elected to be treated as a corporation is treated as a partnership for federal income tax purposes and, therefore, is not a taxable entity and incurs no federal income tax liability. Instead, each partner is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, even if no cash distributions are made to him. Distributions by a partnership to a partner are generally not taxable to the partner unless the amount of cash distributed to him is in excess of his adjusted basis in his partnership interest.

Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to in this discussion as the “Qualifying Income Exception,” exists with respect to publicly traded partnerships 90% or more of the gross income of which for every taxable year consists of “qualifying income.” Qualifying income includes income and gains derived from the exploration, development, mining or production, processing, transportation and marketing of natural resources, including oil, natural gas, and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than 3% of our current gross income does not constitute qualifying income; however, this estimate could change from time to time. Based on and subject to this estimate, the factual representations made by us, and a review of the applicable legal authorities, Andrews Kurth LLP is of the opinion that more than 90% of our current gross income constitutes qualifying income. The portion of our income that is qualifying income can change from time to time.

No ruling has been or will be sought from the IRS, and the IRS has made no determination as to our status or the status of our operating subsidiaries for federal income tax purposes or whether our operations generate “qualifying income” under Section 7704 of the Internal Revenue Code. Instead, we will rely on the opinion of Andrews Kurth LLP. Andrews Kurth LLP is of the opinion, based upon the Internal Revenue Code, its regulations, published revenue rulings, court decisions and the representations described below, that we are and will continue to be classified as a partnership, and each of our operating subsidiaries will be disregarded as an entity separate from us, for federal income tax purposes.

In rendering its opinion, Andrews Kurth LLP has relied on factual representations made by us. The representations made by us upon which Andrews Kurth LLP has relied include:

- Neither we, nor any of our limited liability company subsidiaries, have elected nor will we elect to be treated as a corporation; and
- For each taxable year, more than 90% of our gross income has been and will be income that Andrews Kurth LLP has opined or will opine is “qualifying income” within the meaning of Section 7704(d) of the Internal Revenue Code.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery, we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation and then distributed that stock to common unitholders in liquidation of their interests in us. This deemed contribution and liquidation would be tax-free to common unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to common unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a common unitholder would be treated as taxable dividend income to the extent of our current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital to the extent of the common unitholder’s tax basis in his units, or taxable capital gain, after the common unitholder’s tax basis in his units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a common unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The remainder of this section is based on Andrews Kurth LLP's opinion that we are and will continue to be classified as a partnership for federal income tax purposes.

Common Unitholder Status

Common unitholders who become members of Constellation Energy Partners LLC will be treated as partners of Constellation Energy Partners LLC for federal income tax purposes. Also, common unitholders whose units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their units will be treated as partners of Constellation Energy Partners LLC for federal income tax purposes.

A beneficial owner of units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please read "—Tax Consequences of Unit Ownership—Treatment of Short Sales."

Items of our income, gain, loss, or deduction are not reportable by a common unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a common unitholder who is not a partner for federal income tax purposes would therefore be fully taxable as ordinary income. These common unitholders are urged to consult their own tax advisors with respect to their status as partners in us for federal income tax purposes.

The references to "common unitholders" in the discussion that follows are to persons who are treated as partners in Constellation Energy Partners LLC for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-Through of Taxable Income

We do not pay any federal income tax. Instead, each common unitholder is be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether corresponding cash distributions are received by him. Consequently, we may allocate income to a common unitholder even if he has not received a cash distribution. Each common unitholder is required to include in income his share of our income, gain, loss and deduction for our taxable year or years ending with or within his taxable year. Our taxable year ends on December 31.

Treatment of Distributions

Distributions made by us to a common unitholder generally are not be taxable to him for federal income tax purposes to the extent of his tax basis in his units immediately before the distribution. Cash distributions made by us to a common unitholder in an amount in excess of his tax basis in his units generally are considered to be gain from the sale or exchange of those units, taxable in accordance with the rules described under "—Disposition of Units" below. To the extent that cash distributions made by us cause a common unitholder's "at risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read "—Limitations on Deductibility of Losses."

Any reduction in a common unitholder's share of our liabilities for which no partner bears the economic risk of loss, known as "non-recourse liabilities," will be treated as a distribution of cash to that common unitholder. A decrease in a common unitholder's percentage interest in us because of our issuance of additional units will decrease his share of our nonrecourse liabilities and thus will result in a corresponding deemed distribution of cash, which may constitute a non-pro rata distribution. A non-pro rata distribution of money or property may result in ordinary income to a common unitholder, regardless of his tax basis in his units, if the distribution reduces the common unitholder's share of our "unrealized receivables," including recapture of intangible drilling costs, depletion and depreciation recapture, and/or substantially appreciated "inventory items," both as defined in Section 751 of the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, he will be treated as having received his proportionate share of the Section 751 Assets and having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the common unitholder's realization of ordinary income. That income will equal the excess of (1) the non-pro rata portion of that distribution over (2) the common unitholder's tax basis for the share of Section 751 Assets deemed relinquished in the exchange.

Basis of Units

A common unitholder's initial tax basis for his units will be the amount he paid for the units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income and by any increases in his share of our nonrecourse liabilities. That basis generally will be decreased, but not below zero, by distributions to him from us, by his share of our losses, by depletion deductions taken by him to the extent such deductions do not exceed his proportionate share of the adjusted tax basis of the underlying producing properties, by any decreases in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A common unitholder's share of our nonrecourse liabilities will generally be based on his share of our profits. Please read "—Disposition of Units—Recognition of Gain or Loss."

Limitations on Deductibility of Losses

The deduction by a common unitholder of his share of our losses is limited to his tax basis in his units and, in the case of an individual common unitholder or a corporate common unitholder, if more than 50% of the value of its stock is owned directly or indirectly by or for five or fewer individuals or some tax-exempt organizations, to the amount for which the common unitholder is considered to be "at risk" with respect to our activities, if that amount is less than his tax basis. A common unitholder must recapture losses deducted in previous years to the extent that distributions cause his at-risk amount to be less than zero at the end of any taxable year. Losses disallowed to a common unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction in a later year to the extent that his tax basis or at-risk amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a common unitholder can be offset by losses that were previously suspended by the at-risk limitation but may not be offset by losses suspended by the basis limitation. Any excess loss above that gain previously suspended by the at risk or basis limitations is no longer utilizable.

In general, a common unitholder will be at risk to the extent of his tax basis in his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the common unitholder or can look only to the units for repayment. A common unitholder's at-risk amount will increase or decrease as the tax basis of the common unitholder's common units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities. Moreover, a common unitholder's at risk amount will decrease by the amount of the common unitholder's depletion deductions and will increase to the extent of the amount by which the common unitholder's percentage depletion deductions with respect to our property exceed the common unitholder's share of the basis of that property.

The at risk limitation applies on an activity-by-activity basis, and in the case of oil and natural gas properties, each property is treated as a separate activity. Thus, a taxpayer's interest in each oil or gas property is generally required to be treated separately so that a loss from any one property would be limited to the at risk amount for that property and not the at risk amount for all the taxpayer's oil and natural gas properties. It is uncertain how this rule is implemented in the case of multiple oil and natural gas properties owned by a single entity treated as a partnership for federal income tax purposes. However, for taxable years ending on or before the date on which further guidance is published, the IRS will permit aggregation of oil or gas properties we own in computing a common unitholder's at risk limitation with respect to us. If a common unitholder must compute his at risk amount separately with respect to each oil or gas property we own, he may not be allowed to utilize his share of losses or deductions attributable to a particular property even though he has a positive at risk amount with respect to his units as a whole.

The passive loss limitation generally provides that individuals, estates, trusts and some closely held corporations and personal service corporations are permitted to deduct losses from passive activities, which are generally defined as trade or business activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitation is applied separately with respect to each publicly traded partnership. Consequently, any losses we generate will be available to offset only our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments, a common unitholder's investments in other publicly traded partnerships, or a common unitholder's salary or active business income. If we dispose of all or only a part of our interest in an oil and gas property, common unitholders will be able to offset their suspended passive activity losses from our activities against the gain, if any, on the disposition. Any previously suspended losses in excess of the amount of gain recognized will remain suspended. Notwithstanding whether a natural gas and oil property is a separate activity, passive losses that are not deductible because they exceed a common unitholder's share of income we generate may only be deducted by the common unitholder in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive activity loss rules are applied after certain other applicable limitations on deductions, including the at-risk rules and the tax basis limitation.

A common unitholder's share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

Limitation on Interest Deductions

The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;
- our interest expense attributable to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a common unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit.

Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment. The IRS has indicated that net passive income earned by a publicly traded partnership will be treated as investment income to its common unitholders. In addition, the common unitholder's share of our portfolio income will be treated as investment income.

Entity-Level Collections

If we are required or elect under applicable law to pay any federal, state or local income tax on behalf of any common unitholder or any former common unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the common unitholder on whose behalf the payment was made. If the payment is made on behalf of a common unitholder whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current common unitholders. We are authorized to amend our limited liability company agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under our limited liability company agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of a common unitholder in which event the common unitholder would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction

In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among the common unitholders in accordance with their percentage interests in us. If we have a net loss for an entire year, the loss will be allocated to our common unitholders according to their percentage interests in us to the extent of their positive capital account balances.

Specified items of our income, gain, loss and deduction will be allocated under Section 704(c) of the Internal Revenue Code to account for the difference between the tax basis and fair market value of our assets at the time of this offering, which assets are referred to in this discussion as “Contributed Property.” These allocations are required to eliminate the difference between a partner’s “book” capital account, credited with the fair market value of Contributed Property, and the “tax” capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the “book-tax disparity.” The effect of these allocations to a common unitholder who purchases units in an offering will be essentially the same as if the tax basis of our assets were equal to their fair market value at the time of the offering. In the event we issue additional units or engage in certain other transactions in the future, Section 704(c) allocations will be made to all holders of partnership interests, to account for the difference between the “book” basis for purposes of maintaining capital accounts and the fair market value of all property held by us at the time of the future transaction. In addition, items of recapture income will be allocated to the extent possible to the common unitholder who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by other common unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in an amount and manner sufficient to eliminate the negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by Section 704(c), will generally be given effect for federal income tax purposes in determining a common unitholder’s share of an item of income, gain, loss or deduction only if the allocation has substantial economic effect. In any other case, a common unitholder’s share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to us;
- the interests of all the common unitholders in profits and losses;
- the interest of all the common unitholders in cash flow; and
- the rights of all the common unitholders to distributions of capital upon liquidation.

Andrews Kurth LLP is of the opinion that, with the exception of the issues described in "—Tax Consequences of Unit Ownership—Section 754 Election," "—Uniformity of Units" and "—Disposition of Units—Allocations Between Transferors and Transferees," allocations under our limited liability company agreement will be given effect for federal income tax purposes in determining a common unitholder's share of an item of income, gain, loss or deduction.

Treatment of Short Sales

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

- none of our income, gain, loss or deduction with respect to those units would be reportable by the common unitholder;
- any cash distributions received by the common unitholder with respect to those units would be fully taxable; and
- all of these distributions would appear to be ordinary income.

Andrews Kurth LLP has not rendered an opinion regarding the treatment of a common unitholder whose units are loaned to a short seller. Therefore, common unitholders desiring to assure their status as partners and avoid the risk of gain recognition are urged to modify any applicable brokerage account agreements to prohibit their brokers from loaning their units. The IRS has announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please also read "—Disposition of Units—Recognition of Gain or Loss."

Alternative Minimum Tax

Each common unitholder is required to take into account his distributive share of any items of our income, gain, loss or deduction for purposes of the alternative minimum tax. The current minimum tax rate for non-corporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income. Prospective common unitholders are urged to consult their tax advisors with respect to the impact of an investment in our units on their liability for the alternative minimum tax.

Tax Rates

In general, the highest effective federal income tax rate for individuals currently is 35% and the maximum federal income tax rate for net capital gains of an individual currently is 15% if the asset disposed of was held for more than 12 months at the time of disposition. The capital gains rate is scheduled to remain at 15% for years 2008 through 2010, and then increase to 20% beginning January 1, 2011.

Section 754 Election

We have made the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. That election will generally permit us to adjust a unit purchaser's tax basis in our assets ("inside basis") under Section 743(b) of the Internal Revenue Code to reflect his purchase price. The Section 743(b) adjustment does not apply to a person who purchases units directly from us, and it belongs only to the purchaser and not to other common unitholders. Please also read, however, "—Allocation of Income, Gain, Loss and Deduction" above. For purposes of this discussion, a common unitholder's inside basis in our assets has two components: (1) his share of our tax basis in our assets ("common basis") and (2) his Section 743(b) adjustment to that basis.

Treasury regulations under Section 743 of the Internal Revenue Code require, if the remedial allocation method is adopted (which we have adopted), a portion of the Section 743(b) adjustment attributable to recovery property to be depreciated over the remaining cost recovery period for the Section 704(c) built-in gain. Under Treasury Regulation Section 1.167(c)-l(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code rather than cost recovery deductions under Section 168 is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Under our limited liability company agreement, we are authorized to take a position to preserve the uniformity of units even if that position is not consistent with the Treasury regulations. Please read "—Uniformity of Units."

Although Andrews Kurth LLP is unable to opine on the validity of this approach because there is no clear authority on this issue, we intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized book-tax disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the unamortized book-tax disparity of the property, or treat that portion as non-amortizable to the extent attributable to property which is not amortizable. This method is consistent with the regulations under Section 743 but is arguably inconsistent with Treasury regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. To the extent a Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized book-tax disparity, we will apply the rules described in the Treasury regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some common unitholders. Please read "—Uniformity of Units." A common unitholder's tax basis for his common units is reduced by his share of our deductions (whether or not such deductions were claimed on an individual's income tax return) so that any position we take that understates deductions will overstate the common unitholder's basis in his common units. Please read "—Disposition of Units - Recognition of Gain or Loss." The IRS may challenge our position with respect to depreciating or amortizing the Section 743(b) adjustment we take to preserve the uniformity of the common units. If such a challenge were sustained, the gain from the sale of common units might be increased without the benefit of additional deductions.

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depletion and depreciation deductions and his share of any gain on a sale of our assets would be less. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his units is lower than those units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built-in loss immediately after the transfer, or if we distribute property and have a substantial basis reduction. Generally a built-in loss or a basis reduction is substantial if it exceeds $250,000.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment we allocated to our tangible assets to goodwill instead. Goodwill, an intangible asset, is generally either non-amortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS or that the resulting deductions will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our

Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year

We use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each common unitholder is required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a common unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than twelve months of our income, gain, loss and deduction. Please read “—Disposition of Units—Allocations Between Transferors and Transferees.”

Depletion Deductions

Subject to the limitations on deductibility of losses discussed above, common unitholders are entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to our oil and natural gas interests. Although the Internal Revenue Code requires each common unitholder to compute his own depletion allowance and maintain records of his share of the adjusted tax basis of the underlying property for depletion and other purposes, we intend to furnish each of our common unitholders with information relating to this computation for federal income tax purposes.

Percentage depletion is generally available with respect to common unitholders who qualify under the independent producer exemption contained in Section 613A(c) of the Internal Revenue Code. For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, natural gas, or derivative products or the operation of a major refinery. Percentage depletion is calculated as an amount generally equal to 15% (and, in the case of marginal production, potentially a higher percentage) of the common unitholder’s gross income from the depletable property for the taxable year. The percentage depletion deduction with respect to any property is limited to 100% of the taxable income of the common unitholder from the property for each taxable year, computed without the depletion allowance. A common unitholder that qualifies as an independent producer may deduct percentage depletion only to the extent the common unitholder’s daily production of domestic crude oil, or the natural gas equivalent, does not exceed 1,000 barrels. This depletable amount may be allocated between oil and natural gas production, with 6,000 cubic feet of domestic natural gas production regarded as equivalent to one barrel of crude oil. The 1,000 barrel limitation must be allocated among the independent producer and controlled or related persons and family members in proportion to the respective production by such persons during the period in question.

In addition to the foregoing limitations, the percentage depletion deduction otherwise available is limited to 65% of a common unitholder’s total taxable income from all sources for the year, computed without the depletion allowance, net operating loss carrybacks, or capital loss carrybacks. Any percentage depletion deduction disallowed because of the 65% limitation may be deducted in the following taxable year if the percentage depletion deduction for such year plus the deduction carryover does not exceed 65% of the common unitholder’s total taxable income for that year. The carryover period resulting from the 65% net income limitation is indefinite.

Common unitholders that do not qualify under the independent producer exemption are generally restricted to depletion deductions based on cost depletion. Cost depletion deductions are calculated by (i) dividing the common unitholder’s share of the adjusted tax basis in the underlying mineral property by the number of mineral units (barrels of oil and thousand cubic feet, or Mcf, of natural gas) remaining as of the beginning of the taxable year and (ii) multiplying the result by the number of mineral units sold within the taxable year. The total amount of deductions based on cost depletion cannot exceed the common unitholder’s share of the total adjusted tax basis in the property.

All or a portion of any gain recognized by a common unitholder as a result of either the disposition by us of some or all of our oil and natural gas interests or the disposition by the common unitholder of some or all of his units may be taxed as ordinary income to the extent of recapture of depletion deductions, except for percentage depletion deductions in excess of the basis of the property. The amount of the recapture is generally limited to the amount of gain recognized on the disposition.

The foregoing discussion of depletion deductions does not purport to be a complete analysis of the complex legislation and Treasury regulations relating to the availability and calculation of depletion deductions by the common unitholders. We encourage each prospective common unitholder to consult his tax advisor to determine whether percentage depletion would be available to him.

Deductions for Intangible Drilling and Development Costs

We elect to currently deduct intangible drilling and development costs (“IDCs”). IDCs generally include our expenses for wages, fuel, repairs, hauling, supplies and other items that are incidental to, and necessary for, the drilling and preparation of wells for the production of oil, natural gas or geothermal energy. The option to currently deduct IDCs applies only to those items that do not have a salvage value.

Although we elect to currently deduct IDCs, each common unitholder will have the option of either currently deducting IDCs or capitalizing all or part of the IDCs and amortizing them on a straight-line basis over a 60-month period, beginning with the taxable month in which the expenditure is made. If a common unitholder makes the election to amortize the IDCs over a 60-month period, no IDC preference amount will result for alternative minimum tax purposes.

Integrated oil companies must capitalize 30% of all their IDCs (other than IDCs paid or incurred with respect to oil and natural gas wells located outside of the United States) and amortize these IDCs over 60 months beginning in the month in which those costs are paid or incurred. If the taxpayer ceases to be an integrated oil company, it must continue to amortize those costs as long as it continues to own the property to which the IDCs relate. An “integrated oil company” is a taxpayer that has economic interests in crude oil deposits and also carries on substantial retailing or refining operations. An oil or gas producer is deemed to be a substantial retailer or refiner if it is subject to the rules disqualifying retailers and refiners from taking percentage depletion. In order to qualify as an “independent producer” that is not subject to these IDC deduction limits, a common unitholder, either directly or indirectly through certain related parties, may not be involved in the refining of more than 75,000 barrels of oil (or the equivalent amount of natural gas) on average for any day during the taxable year or in the retail marketing of oil and natural gas products exceeding $5 million per year in the aggregate.

IDCs previously deducted that are allocable to property (directly or through ownership of an interest in a partnership) and that would have been included in the adjusted basis of the property had the IDC deduction not been taken are recaptured to the extent of any gain realized upon the disposition of the property or upon the disposition by a common unitholder of interests in us. Recapture is generally determined at the common unitholder level. Where only a portion of the recapture property is sold, any IDCs related to the entire property are recaptured to the extent of the gain realized on the portion of the property sold. In the case of a disposition of an undivided interest in a property, a proportionate amount of the IDCs with respect to the property is treated as allocable to the transferred undivided interest to the extent of any gain recognized. See “—Disposition of Units—Recognition of Gain or Loss.”

Deduction for United States Production Activities

Subject to the limitations on the deductibility of losses discussed above and the limitation discussed below, common unitholders will be entitled to a deduction, herein referred to as the Section 199 deduction, equal to a specified percentage of our qualified production activities income that is allocated to such common unitholder. The percentages are 6% for qualified production activities income generated in the years 2007, 2008, and 2009; and 9% thereafter.

Qualified production activities income is generally equal to gross receipts from domestic production activities reduced by cost of goods sold allocable to those receipts, other expenses directly associated with those receipts, and a share of other deductions, expenses and losses that are not directly allocable to those receipts or another class of income. The products produced must be manufactured, produced, grown or extracted in whole or in significant part by the taxpayer in the United States.

For a partnership, the Section 199 deduction is determined at the partner level. To determine his Section 199 deduction, each common unitholder will aggregate his share of the qualified production activities income allocated to him from us with the common unitholder's qualified production activities income from other sources. Each common unitholder must take into account his distributive share of the expenses allocated to him from our qualified production activities regardless of whether we otherwise have taxable income. However, our expenses that otherwise would be taken into account for purposes of computing the Section 199 deduction are only taken into account if and to the extent the common unitholder's share of losses and deductions from all of our activities is not disallowed by the basis rules, the at-risk rules or the passive activity loss rules. Please read "—Tax Consequences of Unit Ownership—Limitations on Deductibility of Losses."

The amount of a common unitholder's Section 199 deduction for each year is limited to 50% of the IRS Form W-2 wages paid by the common unitholder during the calendar year that are deducted in arriving at qualified production activities income. Each common unitholder is treated as having been allocated IRS Form W-2 wages from us equal to the common unitholder's allocable share of our wages that are deducted in arriving at our qualified production activities income for that taxable year. It is not anticipated that we or our subsidiaries will pay material wages that will be allocated to our common unitholders.

This discussion of the Section 199 deduction does not purport to be a complete analysis of the complex legislation and Treasury authority relating to the calculation of domestic production gross receipts, qualified production activities income, or IRS Form W-2 Wages, or how such items are allocated by us to common unitholders. Each prospective common unitholder is encouraged to consult his tax advisor to determine whether the Section 199 deduction would be available to him.

Lease Acquisition Costs

The cost of acquiring oil and natural gas leaseholder or similar property interests is a capital expenditure that must be recovered through depletion deductions if the lease is productive. If a lease is proved worthless and abandoned, the cost of acquisition less any depletion claimed may be deducted as an ordinary loss in the year the lease becomes worthless. Please read "Tax Treatment of Operations—Depletion Deductions."

Geophysical Costs

Geophysical costs paid or incurred in connection with the exploration for, or development of, oil or gas within the U.S. are allowed as a deduction ratably over the 24-month period beginning on the date that such expense was paid or incurred.

Operating and Administrative Costs

Amounts paid for operating a producing well are deductible as ordinary business expenses, as are administrative costs to the extent they constitute ordinary and necessary business expenses which are reasonable in amount.

Tax Basis, Depreciation and Amortization

The tax basis of our assets, such as casing, tubing, tanks, pumping units and other similar property, will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to (i) this offering will be borne by our existing common unitholders, and (ii) any other offering will be borne by our common unitholders as of that time. Please read "—Tax Consequences of Unit Ownership—Allocation of Income, Gain, Loss and Deduction."

To the extent allowable, we may elect to use the depreciation and cost recovery methods that will result in the largest deductions being taken in the early years after assets are placed in service. Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure, or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a common unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his interest in us. Please read "—Tax Consequences of Unit Ownership—Allocation of Income, Gain, Loss and Deduction" and "—Disposition of Units—Recognition of Gain or Loss."

The costs incurred in selling our units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which we may be able to amortize, and as syndication expenses, which we may not amortize. The underwriting discounts and commissions we incur will be treated as syndication expenses.

Valuation and Tax Basis of Our Properties

The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values and the tax bases of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deduction previously reported by common unitholders might change, and common unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Units

Recognition of Gain or Loss

Gain or loss will be recognized on a sale of units equal to the difference between the common unitholder's amount realized and the common unitholder's tax basis for the units sold. A common unitholder's amount realized will equal the sum of the cash or the fair market value of other property he receives plus his share of our nonrecourse liabilities. Because the amount realized includes a common unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us in excess of cumulative net taxable income for a unit that decreased a common unitholder's tax basis in that unit will, in effect, become taxable income if the unit is sold at a price greater than the common unitholder's tax basis in that unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a common unitholder, other than a "dealer" in units, on the sale or exchange of a unit held for more than one year will generally be taxable as capital gain or loss. A portion of this gain or loss, which may be substantial, however, will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to "unrealized receivables" or "inventory items" that we own. The term "unrealized receivables" includes potential recapture items, including depreciation, depletion, and IDC recapture. Ordinary income attributable to unrealized receivables and inventory items may exceed net taxable gain realized on the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a common unitholder may recognize both ordinary income and a capital loss upon a sale of units. Net capital loss may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gain in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method. Treasury regulations under Section 1223 of the Internal Revenue Code allow a selling common unitholder who can identify units transferred with an ascertainable holding period to elect to use the actual holding period of the units transferred. Thus, according to the ruling, a common unitholder will be unable to select high or low basis units to sell as would be the case with corporate stock, but, according to the regulations, may designate specific units sold for purposes of determining the holding period of units transferred. A common unitholder electing to use the actual holding period of units transferred must consistently use that identification method for all subsequent sales or exchanges of units. A common unitholder considering the purchase of additional units or a sale of units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and those Treasury regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer who enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees

In general, our taxable income or loss will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the common unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month (the "Allocation Date"). However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the common unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a common unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

Although simplifying conventions are contemplated by the Code and most publicly traded partnerships use similar simplifying conventions, the use of this method may not be permitted under existing Treasury regulations. Accordingly, Andrews Kurth LLP is unable to opine on the validity of this method of allocating income and deductions between common unitholders. If this method is not allowed under the Treasury regulations, or only applies to transfers of less than all of the common unitholder's interest, our taxable income or losses might be reallocated among the common unitholders. We are authorized to revise our method of allocation between common unitholders, as well as among common unitholders whose interests vary during a taxable year, to conform to a method permitted under future Treasury regulations.

A common unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter but will not be entitled to receive that cash distribution.

Notification Requirements

A common unitholder who sells any of his units, other than through a broker, generally is required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A person who purchases units is required to notify us in writing of that purchase within 30 days after the purchase, unless a broker or nominee will satisfy such requirement. We are required to notify the IRS of any such transfers of units and to furnish specified information to the transferor and transferee. Failure to notify us of a transfer of units may lead to the imposition of substantial penalties.

Constructive Termination

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 common unitholders. In the case of a common unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. A constructive termination occurring on a date other than December 31 will result in us filing two tax returns (and common unitholders receiving two Schedule K-1s) for one calendar year and the cost of the preparation of these returns will be borne by all common unitholders. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Uniformity of Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury Regulation Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the units. Please read "—Tax Consequences of Unit Ownership—Section 754 Election."

We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized book-tax disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the unamortized book-tax disparity of that property, or treat that portion as non-amortizable, to the extent attributable to property which is not amortizable, consistent with the regulations under Section 743 of the Internal Revenue Code. This method is consistent with the Treasury regulations applicable to property depreciable under the accelerated cost recovery system or the modified accelerated cost recovery system, which we expect will apply to substantially all, if not all, of our depreciable property. We also intend to use this method with respect to property that we own, if any, depreciable under Section 167 of the Internal Revenue Code, even though that position may be inconsistent with Treasury regulation Section 1.167(c)-1(a)(6). We do not expect Section 167 to apply to a material portion, if any, of our assets. Please read "—Tax Consequences of Unit Ownership —Section 754 Election." To the extent that the Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized book-tax disparity, we will apply the rules described in the Treasury regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to a common basis or Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our property. If we adopt this position, it may result in lower annual deductions than would otherwise be allowable to some common unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. We will not adopt this position if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the common unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the common unitholders. Our counsel, Andrews Kurth LLP, is unable to opine on the validity of any of these positions. The IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please read "—Disposition of Units—Recognition of Gain or Loss."

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations and other foreign persons raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a common unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to them.

A regulated investment company, or "mutual fund," is required to derive at least 90% of its gross income from certain permitted sources. Income from the ownership of units in a "qualified publicly traded partnership" is generally treated as income from a permitted source. We expect that we will meet the definition of a qualified publicly traded partnership.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the United States because of the ownership of units. As a consequence they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our net income or gain. Under rules applicable to publicly traded partnerships, we will withhold tax, at the highest effective applicable rate, from cash distributions made quarterly to foreign common unitholders. Each foreign common unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8 BEN or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns units will be treated as engaged in a United States trade or business, that corporation may be subject to the United States branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in the foreign corporation's "U.S. net equity," that is effectively connected with the conduct of a United States trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate common unitholder is a “qualified resident.” In addition, this type of common unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

Under a ruling issued by the IRS, a foreign common unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized on the sale or disposition of that unit to the extent the gain is effectively connected with a United States trade or business of the foreign common unitholder. Because a foreign unitholder is considered to be engaged in business in the U.S. by virtue of the ownership of units, under this ruling a foreign unitholder who sells or otherwise disposes of a unit generally will be subject to federal income tax on gain realized on the sale or disposition of the unit. Apart from the ruling, a foreign common unitholder will not be taxed or subject to withholding upon the sale or disposition of a unit if he has owned less than 5% in value of the units during the five-year period ending on the date of the disposition and if the units are regularly traded on an established securities market at the time of the sale or disposition.

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each common unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each common unitholder’s share of income, gain, loss and deduction.

We cannot assure you that those positions will yield a result that conforms to the requirements of the Internal Revenue Code, Treasury regulations or administrative interpretations of the IRS. Neither we nor counsel can assure prospective common unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each common unitholder to adjust a prior year’s tax liability and possibly may result in an audit of his own return. Any audit of a common unitholder’s return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the “Tax Matters Partner” for these purposes. The limited liability company agreement appoints CEPM as our Tax Matters Partner, subject to redetermination by our board of managers from time to time.

The Tax Matters Partner will make some elections on our behalf and on behalf of common unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against common unitholders for items in our returns. The Tax Matters Partner may bind a common unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that common unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the common unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any common unitholder having at least a 1% interest in profits or by any group of common unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each common unitholder with an interest in the outcome may participate.

A common unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a holder of common units to substantial penalties.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

- the name, address and taxpayer identification number of the beneficial owner and the nominee;
- a statement regarding whether the beneficial owner is:
- a person that is not a United States person,
- a foreign government, an international organization or any wholly-owned agency or instrumentality of either of the foregoing, or
- a tax-exempt entity;
- the amount and description of units held, acquired or transferred for the beneficial owner; and
- specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-related Penalties

An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

A substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000. The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

- for which there is, or was, “substantial authority,” or
- as to which there is a reasonable basis and the relevant facts of that position are disclosed on the return.

We believe we will not be classified as a tax shelter. If any item of income, gain, loss or deduction included in the distributive shares of common unitholders could result in that kind of an “understatement” of income for which no “substantial authority” exists, we would be required to disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for common unitholders to make adequate disclosure on their returns to avoid liability for this penalty. More stringent rules would apply to an understatement of tax resulting from ownership of units if we were classified as a “tax shelter.”

A substantial valuation misstatement exists if the value of any property, or the adjusted basis of any property, claimed on a tax return is 150% or more of the amount determined to be the correct amount of the valuation or adjusted basis. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for a corporation other than an S Corporation or a personal holding company). If the valuation claimed on a return is 200% or more than the correct valuation, the penalty imposed increases to 40%.

Reportable Transactions

If we were to engage in a "reportable transaction," we (and possibly you and others) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of transaction publicly identified by the IRS as a "listed transaction" or that it produces certain kinds of losses in excess of $2 million. Our participation in a reportable transaction could increase the likelihood that our federal income tax information return (and possibly your tax return) is audited by the IRS. Please read "—Information Returns and Audit Procedures" above.

Moreover, if we were to participate in a listed transaction or a reportable transaction (other than a listed transaction) with a significant purpose to avoid or evade tax, you could be subject to the following provisions of the American Jobs Creation Act of 2004:

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described above at "—Accuracy-related Penalties,"
- for those persons otherwise entitled to deduct interest on federal tax deficiencies, non-deductibility of interest on any resulting tax liability, and
- in the case of a listed transaction, an extended statute of limitations.

We do not expect to engage in any reportable transactions.

State, Local and Other Tax Considerations

In addition to federal income taxes, you will be subject to other taxes, including state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. We currently do business and own property in Kansas, Maryland, Oklahoma and Alabama. We are registered to do business in Texas. We may also own property or do business in other states in the future. Although an analysis of those various taxes is not presented here, each prospective common unitholder should consider their potential impact on his investment in us. You may not be required to file a return and pay taxes in some states because your income from that state falls below the filing and payment requirement. You will be required, however, to file state income tax returns and to pay state income taxes in many of the states in which we may do business or own property, and you may be subject to penalties for failure to comply with those requirements. In some states, tax losses may not produce a tax benefit in the year incurred and also may not be available to offset income in subsequent taxable years. Some of the states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a common unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular common unitholder's income tax liability to the state, generally does not relieve a nonresident common unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to common unitholders for purposes of determining the amounts distributed by us. Please read "—Tax Consequences of Unit Ownership—Entity-Level Collections." Based on current law and our estimate of our future operations, we anticipate that any amounts required to be withheld will not be material.

It is the responsibility of each common unitholder to investigate the legal and tax consequences, under the laws of pertinent states and localities, of his investment in us. Andrews Kurth LLP has not rendered an opinion on the state local, or foreign tax consequences of an investment in us. We strongly recommend that each prospective common unitholder consult, and depend on, his own tax counsel or other advisor with regard to those matters. It is the responsibility of each common unitholder to file all tax returns, that may be required of him.

INVESTMENT IN OUR COMPANY BY EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA and restrictions imposed by Section 4975 of the Internal Revenue Code. For these purposes, the term “employee benefit plan” includes, but is not limited to, qualified pension, profit–sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or IRAs established or maintained by an employer or employee organization. Among other things, the person with investment discretion with respect to the assets of an employee benefit plan, often called a fiduciary, should consider:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA;
- whether in making the investment, that plan will satisfy the diversification requirements of Section 404(a)(l)(C) of ERISA; and
- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after–tax investment return.

A plan fiduciary should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibits employee benefit plans, and IRAs that are not considered part of an employee benefit plan, from engaging in specified transactions involving “plan assets” with parties that are “parties in interest” under ERISA or “disqualified persons” under the Internal Revenue Code with respect to the plan.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that CEPM also would be a fiduciary of the plan and our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code.

The Department of Labor regulations provide guidance with respect to whether the assets of an entity in which employee benefit plans acquire equity interests would be deemed “plan assets” under some circumstances. Under these regulations, an entity’s assets would not be considered to be “plan assets” if, among other things:

- the equity interests acquired by employee benefit plans are publicly offered securities—i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, freely transferable and registered under some provisions of the federal securities laws;
- the entity is an “operating company,”—i.e., it is primarily engaged in the production or sale of a product or service other than the investment of capital either directly or through a majority owned subsidiary or subsidiaries; or
- there is no significant investment by benefit plan investors, which is defined to mean that less than 25% of the value of each class of equity interest, disregarding some interests held by CEPM, its affiliates, and some other persons, is held by the employee benefit plans referred to above, IRAs and other employee benefit plans not subject to ERISA, including governmental plans.

Our assets should not be considered “plan assets” under these regulations because it is expected that the investment will satisfy the requirements in the first bullet above.

Plan fiduciaries contemplating a purchase of our common units should consult with their own counsel regarding the consequences under ERISA and the Internal Revenue Code in light of the serious penalties imposed on persons who engage in prohibited transactions or other violations.

PLAN OF DISTRIBUTION

We are registering the common units on behalf of the selling unitholders. As used in this prospectus, "selling unitholders" includes donees and pledgees selling common units received from a named selling unitholder after the date of this prospectus.

Under this prospectus, the selling unitholders intend to offer our securities to the public:

- through one or more broker-dealers;
- through underwriters; and
- directly to investors.

The selling unitholders may price the common units offered from time to time:

- at market prices prevailing at the time of any sale under this registration statement;
- at prices related to market prices; or
- at negotiated prices.

We will pay the costs and expenses of the registration and offering of the common units offered hereby. We will not pay any underwriting fees, discounts and selling commissions allocable to each selling unitholder's sale of its respective or common units, which will be paid by the selling unitholders. Broker-dealers may act as agent or may purchase securities as principal and thereafter resell the securities from time to time:

- in or through one or more transactions (which may involve crosses and block transactions) or distributions;
- on the NYSE Arca;
- in the over-the-counter market; or
- in private transactions.

Broker-dealers or underwriters may receive compensation in the form of underwriting discounts or commissions and may receive commissions from purchasers of the securities for whom they may act as agents. If any broker-dealer purchases the securities as principal, it may effect resales of the securities from time to time to or through other broker-dealers, and other broker-dealers may receive compensation in the form of concessions or commissions from the purchasers of securities for whom they may act as agents. In no event will the compensation to be paid to NASD members in connection with this offering exceed 10% plus 0.5% for bona fide due diligence.

To the extent required, the names of the specific managing underwriter or underwriters, if any, as well as other important information, will be set forth in prospectus supplements. In that event, the discounts and commissions the selling unitholders will allow or pay to the underwriters, if any, and the discounts and commissions the underwriters may allow or pay to dealers or agents, if any, will be set forth in, or may be calculated from, the prospectus supplements. Any underwriters, brokers, dealers and agents who participate in any sale of the securities may also engage in transactions with, or perform services for, us or our affiliates in the ordinary course of their businesses.

The selling unitholders and any broker-dealers or agents that are involved in selling the common units may be deemed to be "underwriters" within the meaning of the Securities Act in connection with such sales. To the extent any of the selling unitholders are broker-dealers, they are, according to SEC interpretations, "underwriters" within the meaning of the Securities Act. In such event, any commissions received by such broker-dealers or agents and any profit on the resale of the common units purchased by them may be deemed to be underwriting commissions or discounts under the Securities Act.

In addition, the selling unitholders have advised us that they may sell the common units in compliance with Rule 144, if available, or pursuant to other available exemptions from the registration requirements under the Securities Act, rather than pursuant to this prospectus.

To the extent required, this prospectus may be amended or supplemented from time to time to describe a specific plan of distribution.

We have agreed to indemnify the selling unitholder and each underwriter, selling agent or other securities professional, if any, against certain liabilities to which they may become subject in connection with the sale of the common units owned by the selling unitholder and registered under this prospectus, including liabilities arising under the Securities Act of 1933.

SELLING UNITHOLDERS

This prospectus covers the offering for resale of up to 2,298,060 common units by the selling unitholders identified below. These common units represent common units purchased by and common units issued upon conversion of Class E units purchased by such selling unitholders in our equity private placement which closed on April 23, 2007. The total amount of common units that may be sold hereunder will not exceed the number of units offered hereby. Please read "Plan of Distribution."

The following table sets forth information about the maximum number of common units that may be offered from time to time by each selling unitholder under this prospectus. The selling unitholders identified below may currently hold or acquire at any time common units in addition to those registered hereby. In addition, the selling unitholders identified below may sell, transfer or otherwise dispose of some or all of their common units in transactions exempt from or not subject to the registration requirements of the Securities Act. Accordingly, we cannot give an estimate as to the amount of units that will be held by the selling unitholders upon termination of this offering.

Information concerning the selling unitholders may change from time to time and, if necessary, we will supplement this prospectus accordingly.

To our knowledge, none of the selling unitholders has, or has had within the past three years, any position, office or other material relationship with us or any of our predecessors or affiliates, other than their ownership of our common units.

Selling Unitholder	Total Number of Common Units that may be Sold(1)	Percentage of Common Units Outstanding(2)
Agile Nexus Multi Strategy Fund, L.P.(3)	18,397	*
Agile Performance Fund, L.P.(3)	753	*
GPS High Yield Equities Fund LP(4)	21,352	*
GPS Income Fund LP(4)	87,358	*
GPS MLP Fund LP(4)	115,033	*
GPS New Equity Fund LP(4)	228,267	1.2
Lehman Brothers Inc.(5)	216,850	1.2
Lehman Brothers MLP Opportunity Fund L.P.(6)	574,515	3.1
Royal Bank of Canada(7)	461,021	2.5
Structured Finance Americas, LLC(8)	344,708	1.9
ZLP Fund, L.P.(9)	229,806	1.2

* Represents beneficial ownership of less than 1%.

(1) Includes an aggregate of 90,376 common units underlying Class E units that were converted into common units on a one-for-one basis on June 26, 2007.

(2) Calculated based on 18,532,887 common units outstanding as of September 30, 2007.

(3) Representatives of this selling unitholder have advised us that the selling unitholder is an affiliate of a registered broker-dealer; however, the selling unitholder acquired the common units in the ordinary course of business and, at the time of the acquisition, had no agreements or understandings, directly or indirectly, with any party to distribute the common units held by this selling unitholder. This selling unitholder has advised us that voting and dispositive power with respect to the common units held by it is held by Neal R. Greenberg.

(4) Representatives of these selling unitholders have advised us that voting and dispositive power with respect to the common units held by each of them is held by Brett Messing and Steven Sugarman.

(5) Representatives of this selling unitholder have advised us that the selling unitholder is a registered broker-dealer. As such, the selling unitholder is, under the interpretation of the Securities and Exchange

Commission, an "underwriter" within the meaning of the Securities Act of 1933, as amended. Please see "Plan of Distribution" for required disclosure regarding this selling unitholder. This selling unitholder has advised us that voting and dispositive power with respect to the common units held by it is held by Lehman Brothers Holdings Inc., a publicly traded entity. In addition, this selling unitholder has represented to us that it has no plans to participate in the distribution of common units in any capacity other than that of a selling unitholder.

(6) Representatives of this selling unitholder have advised us that the selling unitholder is an affiliate of a registered broker-dealer; however, the selling unitholder acquired the common units in the ordinary course of business and, at the time of the acquisition, had no agreements or understandings, directly or indirectly, with any party to distribute the common units held by such selling unitholder. This selling unitholder has advised us that voting and dispositive power with respect to the common units held by it is held by Michael J. Cannon, Kyriacos Loupis and Jeffrey P. Wood.

(7) Representatives of this selling unitholder have advised us that the selling unitholder is an affiliate of a registered broker-dealer; however, the selling unitholder acquired the common units in the ordinary course of business and, at the time of the acquisition, had no agreements or understandings, directly or indirectly, with any party to distribute the common units held by this selling unitholder. This unitholder has advised us that voting and dispositive power with respect to the common units held by it is held by Royal Bank of Canada, a publicly traded entity.

(8) Deutsche Bank AG, a German banking corporation, holds voting and dispositive power with respect to the common units held by the selling unitholder. Representatives of this selling unitholder have advised us that the selling unitholder is an affiliate of a registered broker-dealer; however, the selling unitholder acquired the common units in the ordinary course of business and, at the time of the acquisition, had no agreements or understandings, directly or indirectly, with any party to distribute the common units held by such selling unitholder.

(9) Representatives of this selling unitholder have advised us that the selling unitholder is an affiliate of a registered broker-dealer; however, the selling unitholder acquired the common units in the ordinary course of business and, at the time of the acquisition, had no agreements or understandings, directly or indirectly, with any party to distribute the common units held by this selling unitholder. This unitholder had advised that voting and dispositive power with respect to the common units held by it is held by Stuart J. Zimmer and Craig M. Lucas.

VALIDITY OF THE UNITS

The validity of the common units will be passed upon for us by Andrews Kurth LLP, Houston, Texas.

EXPERTS

The financial statements of Constellation Energy Partners LLC as of December 31, 2006 and 2005, for the year ended December 31, 2006 and for the period February 7, 2005 (inception) through December 31, 2005 and of Everlast Energy LLC as of and for the year ended December 31, 2004 and for the period January 1, 2005 through June 12, 2005, incorporated in this prospectus by reference to the Annual Report on Form 10-K of Constellation Energy Partners LLC for the year ended December 31, 2006, the audited historical statements of direct revenues and direct operating expenses of the natural gas and oil properties acquired from EnergyQuest Resources, LP and the audited historical financial statements of Kansas Processing EQR, LLC, included as Exhibit 99.1 pages F-1 through F-5 and Exhibit 99.2 pages F-1 through F-8, respectively, in Constellation Energy Partners LLC's Current Report on Form 8-K/A dated July 3, 2007 and the statements of revenues and direct operating expenses of certain oil and gas properties acquired from Newfield Exploration Mid-Continent Inc., included as Exhibit 99.1 pages 1 through 7 in Constellation Energy Partners LLC's Current Report on Form 8-K/A dated October 12, 2007, have been so incorporated in reliance on the reports of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The financial statements of AMVEST Osage, Inc. as of July 31, 2006 and 2005 and for each of the three years in the period ended July 31, 2006, incorporated in this Post-Effective Amendment No. 1 to Registration Statement No. 333-144388 by reference from Constellation Energy Partners LLC's Current Report on Form 8-K/A filed on September 14, 2007 have been audited by Deloitte & Touche LLP, independent auditors as stated in their report (which report expresses an unqualified opinion on the financial statements and includes an explanatory paragraph relating to supplemental information), which is incorporated herein by reference, and has been so incorporated in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

Certain information included in this prospectus regarding our estimated quantities of natural gas reserves was prepared by Netherland, Sewell & Associates, Inc.

WHERE YOU CAN FIND MORE INFORMATION

We have filed a registration statement with the SEC under the Securities Act of 1933, as amended, that registers the offer and sale of the common units covered by this prospectus. The registration statement, including the exhibits, contains additional relevant information about us. In addition, we file annual, quarterly and other reports and other information with the SEC. You may read and copy any document we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the SEC's Public Reference Room. The SEC maintains an Internet site that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC. Our SEC filings are available on the SEC's web site at *http://www.sec.gov*. You also can obtain information about us at the offices of the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

The SEC allows us to "incorporate by reference" the information we have filed with the SEC. This means that we can disclose important information to you without actually including the specific information in this prospectus by referring you to other documents filed separately with the SEC. The information incorporated by reference is an important part of this prospectus.

We incorporate by reference in this prospectus the following documents that we have previously filed with the SEC:

- Annual Report on Form 10-K (File No. 1-33147) for the year ended December 31, 2006 filed on March 12, 2007;
- Quarterly Reports on Form 10-Q (File No. 1-33147) for the quarter ended March 31, 2007 filed on May 10, 2007, for the quarter ended June 30, 2007 filed on August 10, 2007 and for the quarter ended September 30, 2007 filed on November 14, 2007;
- Current Reports on Form 8-K (File No. 1-33147) filed on March 9, 2007 (except for the information under Item 7.01 and the related exhibit), April 24, 2007, May 25, 2007, July 2, 2007, July 16, 2007, July 26, 2007, August 3, 2007, August 6, 2007, August 17, 2007, September 26, 2007, October 18, 2007, November 19, 2007 and November 26, 2007;
- Current Reports on Form 8-K/A (File No. 1-33147) filed on July 5, 2007, September 14, 2007 and October 12, 2007; and
- The description of our common units contained in our registration statement on Form 8-A (File No. 1-33147) filed on November 13, 2006.

These reports contain important information about us, our financial condition and our results of operations.

Nothing in this prospectus shall be deemed to incorporate information furnished to, but not filed with, the SEC pursuant to Item 2.02 or Item 7.01 of Form 8-K (or corresponding information furnished under Item 9.01 or included as an exhibit).

We make available free of charge on or through our Internet website, *http://www.constellationenergypartners.com*, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Information contained on our Internet website is not part of this prospectus.

You may obtain any of the documents incorporated by reference in this prospectus from the SEC through the SEC's website at the address provided above. You also may request a copy of any document incorporated by reference in this prospectus (excluding any exhibits to those documents, unless the exhibit is specifically incorporated by reference in this document), at no cost, by visiting our Internet website at *http://www.constellationenergypartners.com*, or by writing or calling us at the following address:

Investor Relations
Constellation Energy Partners LLC
111 Market Place
Baltimore, Maryland 21202
Telephone: (410) 864-6440

You should rely only on the information incorporated by reference or provided in this prospectus. We have not authorized anyone else to provide you with any information. You should not assume that the information incorporated by reference or provided in this prospectus is accurate as of any date other than the date on the front of each document.

We are also subject to the information requirements of the Exchange Act, and in accordance therewith files reports and other information with the SEC. You may read our filings on the SEC's web site and at the SEC's Public Reference Room described above.

APPENDIX A

GLOSSARY OF TERMS

Adjusted Operating Surplus for any period means:

(a) Operating Surplus generated with respect to that period; *less*

(b) any net increase in working capital borrowings with respect to that period (excluding any such borrowings to the extent the proceeds are distributed to the record holder of the Class D interests); *less*

(c) any net reduction in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; *plus*

(d) any net decrease in working capital borrowings with respect to that period; *plus*

(e) any net increase in cash reserves for operating expenditures made with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Available Cash means, for any quarter ending prior to liquidation:

(a) the sum of:

(i) all cash and cash equivalents of Constellation Energy Partners LLC 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 Constellation Energy Partners LLC 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 Constellation Energy Partners LLC 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 Constellation Energy Partners LLC 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 Initial 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 board of managers so determines.

Bcf. One billion cubic feet.

Capital Surplus is generated by:

(a) borrowings other than working capital borrowings;

(b) sales of debt and equity securities; and

(c) sales or other disposition of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as a part of normal retirements or replacements of assets.

Developed acres. Acres spaced or assigned to productive wells or units.

Development well. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Exploitation. A drilling or other project which may target proved or unproved reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Mcf. One thousand cubic feet.

Mcf/d. One thousand cubic feet per day.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcf/d. One MMcf per day.

Operating expenditures means all expenditures of Constellation Energy Partners LLC and its subsidiaries (or Constellation Energy Partners LLC's proportionate share in the case of subsidiaries that are not wholly-owned), including taxes, amounts paid for services under the management services agreement, payments made in the ordinary course of business under commodity hedge contracts (other than payments in connection with termination of same prior to its termination date), *provided* that with respect to amounts paid in connection with the initial purchase or placing of a commodity hedge contract, such amounts shall be amortized over the life of the applicable commodity hedge contract and upon its termination, if earlier, manager and officer compensation, compensation paid to our board of managers, repayment of working capital borrowings, debt service payments, and estimated maintenance capital expenditures, *provided* that operating expenditures will not include:

- repayment of working capital borrowings deducted from operating surplus pursuant to subparagraph (h) of the definition of operating surplus when such repayment actually occurs;
- payments (including prepayments) of principal of and premium on indebtedness, other than working capital borrowings;
- capital expenditures made for acquisitions or for capital improvements, or expansion capital expenditures;
- actual maintenance capital expenditures;
- investment capital expenditures;
- payment of transaction expenses relating to interim capital transactions; or
- distributions to members (including distributions in respect of our Class D interests and management incentive interests).

Where capital expenditures are made in part for acquisitions or for capital improvements and in part for other purposes, our board of managers, with the concurrence of the conflicts committee, shall determine the allocation between the amounts paid for each.

Operating surplus for any period means:

(a) $20.0 million (if we choose to distribute as operating surplus up to $20.0 million of cash we receive in the future from non-operating sources such as asset sales, issuances of securities and long-term borrowings); *plus*

(b) all of our cash receipts after the closing of this offering, excluding cash from (1) borrowings that are not working capital borrowings, (2) sales of equity and debt securities and (3) sales or other dispositions of assets outside the ordinary course of business; *plus*

(c) working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; *plus*

(d) cash distributions paid on equity issued to finance all or a portion of the construction, replacement or improvement of a capital asset (such as equipment or reserves) during the period beginning on the date that the group member enters into a binding obligation to commence the construction, acquisition or improvement of a capital improvement or replacement of a capital asset and ending on the earlier to occur of the date the capital improvement or capital asset commences commercial service or the date that it is abandoned or disposed of; *plus*

(e) if the right to receive distributions (other than distributions in liquidation) on the Class D interests terminates before December 31, 2012, the excess of the amount of the original $8.0 million contribution by CHI for the Class D interests over the cumulative cash distributions paid on the Class D interests before such termination shall be included in operating surplus, such inclusion to occur over a series of quarters with the amount included in each quarter to be equal to the amount of the payment a group member makes to the Trust in respect of the NPI for such quarter that would not have been paid but for termination of the sharing arrangement; *less*

(f) our operating expenditures after the closing of this offering; *less*

(g) the amount of cash reserves established by our board of managers to provide funds for future operating expenditures; *less*

(h) all working capital borrowings not repaid within twelve months after having been incurred.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Proved natural gas reserves are the estimated quantities of natural gas, crude oil and natural gas liquids which geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions.

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves or *PUDs*. Proved natural gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Recompletion. The completion for production of an existing wellbore in another formation than the one in which the well has been previously completed.

Refracture. The process of applying hydraulic pressure to an oil or natural gas bearing geological formation to crack the formation and stimulate the release of oil and natural gas.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Standardized Measure. 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 the estimation) without giving effect to non-property related expenses such as general and administrative expenses and debt service expenses or to depreciation, depletion and amortization and discounted using an annual rate of 10%. Standardized Measure does not give effect to the derivative transactions and excludes reserves attributable to the NPI. We have excluded future income taxes from our standardized measure, as we are not a taxable entity.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working capital borrowings. Borrowings used solely for working capital purposes or to pay distributions to members made pursuant to a credit facility, commercial paper facility or other similar financing arrangement, *provided* that when it is incurred it is the intent of the borrower to repay such borrowings within 12 months from other than Working Capital Borrowings.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

2,298,060 Common Units

Representing Class B Limited Liability Company Interests

PROSPECTUS

December 6, 2007