UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2007

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to .

Commission File Number 001-33147

Constellation Energy Partners LLC

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**11-3742489**
(State of organization)	**(I.R.S. Employer Identification No.)**
111 Market Place	**21202**

Baltimore, Maryland
(Address of Principal Executive Offices) **(Zip Code)**
Telephone Number: (410) 468-3500

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

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

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer þ

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

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

Common Units outstanding on July 31, 2007: 16,056,952 units

Table of Contents

TABLE OF CONTENTS

Table of Contents

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Income

(Unaudited)

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(In 000 s except unit data)			
Revenues				
Oil and gas sales	$ 15,190	$ 7,858	$ 26,497	$ 17,605
Loss from mark-to-market activities (see Note 5)	(2,619)		(5,401)	
Total revenues	12,571	7,858	21,096	17,605
Expenses:				
Operating expenses:				
Lease operating expenses	3,150	1,583	4,745	3,495
Production taxes	685	333	1,144	909
General and administrative	1,771	1,636	3,390	2,731
Loss (gain) on sale of asset	(1)		94	
Depreciation, depletion, and amortization	3,584	2,066	5,543	3,811
Accretion expense	77	35	113	71
Total operating expenses	9,266	5,653	15,029	11,017
Other expense (income)				
Interest expense	1,266	1	1,825	1
Interest income	(84)	(149)	(135)	(198)
Other income	(70)		(70)	
Total other expenses (income)	1,112	(148)	1,620	(197)
Total expenses	10,378	5,505	16,649	10,820
Net income	$ 2,193	$ 2,353	$ 4,447	$ 6,785
Other comprehensive income (loss)	6,175	914	(3,605)	914
Comprehensive income	$ 8,368	$ 3,267	$ 842	$ 7,699
Earnings per unit				
Earnings per unit Basic	$ 0.17	$ 0.21	$ 0.36	$ 0.60
Units outstanding Basic	13,072,577	11,320,300	12,201,279	11,320,300
Earnings per unit Diluted	$ 0.17	$ 0.21	$ 0.36	$ 0.60
Units outstanding Diluted	13,072,577	11,320,300	12,201,279	11,320,300
Distributions declared and paid per unit	$ 0.4625	$	$ 0.6736	$

See accompanying notes to consolidated financial statements.

Table of Contents

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

	June 30, 2007 (Unaudited)	December 31, 2006
	(In 000 s)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 7,668	$ 7,485
Accounts receivable	9,717	9,609
Prepaid expenses	258	317
Risk management assets	5,922	8,654
Other	2,033	22
Total current assets	25,598	26,087
Natural gas properties (see Note 7)		
Natural gas properties, equipment and facilities	306,448	181,995
Material and supplies	546	1,264
Less accumulated depreciation, depletion and amortization	(17,126)	(11,620)
Net natural gas properties	289,868	171,639
Other assets		
Debt issue costs (net of accumulated amortization of $220 at June 30, 2007 and $48 at December 31, 2006)	1,229	1,138
Risk management assets	1,839	4,761
Other non-current assets	4,050	72
Total assets	$ 322,584	$ 203,697
LIABILITIES AND MEMBERS EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 2,364	$ 66
Payable to affiliate	1,822	2,836
Accrued liabilities	3,847	3,017
Environmental liabilities	717	721
Royalty payable	2,999	2,367
Total current liabilities	11,749	9,007
Other liabilities		
Asset retirement obligation	5,933	2,730
Mark-to-market derivative liabilities	1,873	
Debt	82,500	22,000
Total other liabilities	90,306	24,730
Total liabilities	102,055	33,737
Commitments and contingencies (see Note 9)		
Class D Interests	7,667	8,000
Members equity		
Class A units, 273,305 and 226,406 shares authorized, issued and outstanding, respectively	4,117	2,977

Class B units, 13,841,954 and 11,093,894 shares authorized, respectively, and 13,391,954 and 11,093,894 shares issued and outstanding, respectively	199,237	145,870
Accumulated other comprehensive income	9,508	13,113
Total members equity	212,862	161,960
Total liabilities and members equity	$ 322,584	$ 203,697

See accompanying notes to consolidated financial statements.

2

Table of Contents

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(In 000 s)	
Cash flows from operating activities:		
Net income	$ 4,447	$ 6,785
Adjustments to reconcile net income to cash (used in) provided by operating activities:		
Expenses paid by CCG on behalf of CEP		571
Depreciation, depletion and amortization	5,543	3,811
Amortization of debt issuance costs	172	
Accretion of plugging and abandonment liability	113	71
Equity earnings in affiliate	(70)	
Loss from disposition of property and equipment	94	
Hedge ineffectiveness	(174)	
Loss from mark-to-market activities	5,401	
Changes in Assets and Liabilities:		
Change in net derivative activities	(1,305)	
(Increase) decrease in accounts receivable	(108)	1,869
Decrease (increase) in prepaid expenses	59	(75)
Increase in other assets	(1,995)	(807)
Increase (decrease) in accounts payable	2,998	(3,673)
(Decrease) increase in payable to affiliate	(1,014)	1,486
Increase in accrued liabilities	1,039	7
Increase (decrease) in royalty payable	632	(1,240)
Net cash provided by operating activities	15,832	8,805
Cash flows from investing activities:		
Acquisition of natural gas properties	(114,896)	(261)
Development of natural gas properties	(10,998)	(7,285)
Proceeds from sale of equipment	181	
Distributions from equity affiliate	100	
Investment in affiliate cash pool		(12,199)
Net cash used in investing activities	(125,613)	(19,745)
Cash flows from financing activities:		
Members distributions	(9,043)	
Proceeds from issuance of debt	60,500	
Repayment of debt		(11)
Proceeds from issuance of units	58,770	
Debt issue costs	(263)	
Net cash provided by (used in) financing activities	109,964	(11)
Net increase (decrease) in cash	183	(10,951)
Cash and cash equivalents, beginning of period	7,485	14,831

Cash and cash equivalents, end of period	$	7,668	$	3,880
Supplemental disclosures of cash flow information:				
Non-cash items				
Expenses paid by CCG on behalf of CEP	$		$	571
Accrued capital expenditures		1,266		1,262
Cash received during the period for interest		149		
Cash paid during the period for interest	$	(912)	$	2

See accompanying notes to consolidated financial statements.

Table of Contents

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Changes in Members Equity

(Unaudited)

	Class A		Class B		Accumulated Other Comprehensive	Total Members
	Units	Amount	Units	Amount	Income	Equity
			(In 000 s, except unit amounts)			
Balance, December 31, 2006	226,406	$ 2,977	11,093,894	$ 145,870	$ 13,113	$ 161,960
Distributions		(174)		(8,536)		(8,710)
Change in fair value of commodity hedges					(8,341)	(8,341)
Cash gains on settlement of commodity hedges					4,192	4,192
Change in fair value of interest rate hedges					544	544
Sale of units, net of offering expense of $13	46,899	1,225	2,298,060	57,545		58,770
Net income		89		4,358		4,447
Balance, June 30, 2007	273,305	$ 4,117	13,391,954	$ 199,237	$ 9,508	$ 212,862

See accompanying notes to consolidated financial statements.

4

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

The consolidated financial statements at June 30, 2007 and for the three and six months ended June 30, 2007 and 2006, are unaudited, but in the opinion of management include all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles (GAAP) have been condensed or omitted under Securities and Exchange Commission (SEC) rules and regulations. The results reported in these unaudited consolidated financial statements should not necessarily be taken as indicative of results that may be expected for the entire year.

The financial information included herein should be read in conjunction with the financial statements and notes in the Company s Annual Report on Form 10-K for the year ended December 31, 2006. Certain amounts in the consolidated financial statements and notes thereto have been reclassified to conform to the 2007 financial statement presentation.

CBM Equity IV Holdings, LLC was organized as a limited liability company on February 7, 2005 under the laws of the State of Delaware and had no principal operations prior to the Company s acquisition of the Company s properties in the Robinson s Bend Field (the Robinson s Bend Assets) from Everlast Energy LLC (Everlast) on June 13, 2005. On May 10, 2006, CBM Equity IV Holdings, LLC changed its name to Constellation Energy Resources LLC. On July 18, 2006, Constellation Energy Resources LLC changed its name to Constellation Energy Partners LLC (CEP or the Company). The Company is a related party of Constellation Energy Commodities Group, Inc. (CCG), which is owned by Constellation Energy Group, Inc. (NYSE: CEG) (Constellation or CEG). CEP completed its initial public offering on November 20, 2006, and is traded on the NYSE Arca under the symbol CEP. The Company is currently focused on the development, exploitation and acquisition of oil and natural gas properties in the Robinson s Bend Field located in the Black Warrior Basin in Alabama and in the Cherokee Basin of Oklahoma and Kansas.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Company s significant accounting policies are consistent with those discussed in its Annual Report on Form 10-K for the year ended December 31, 2006. The information below provides updating information with respect to those policies.

Principles of Consolidation

The Company s consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. The Company accounts for investments in companies where it has the ability to exert significant influence over, but not control over operating and financial policies, using the equity method of accounting.

Mark-to-Market Accounting

The Company records revenues using the mark-to-market method of accounting for derivative contracts for which it is not permitted to use hedge accounting. A discussion of the Company s hedge accounting is included in Note 5, Derivative and Financial Instruments. These mark-to-market activities include derivative contracts for natural gas commodities. Under the mark-to-market method of accounting, the Company records the fair value of these derivatives as mark-to-market derivative assets and liabilities at the time of the contract execution. The Company records the fair market value changes in its mark-to-market derivatives in its Consolidated Statements of Operations.

3. NEW ACCOUNTING PRONOUNCEMENTS

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements.* SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures for fair value measurements. SFAS No. 157 is effective for all fair value measurements beginning January 1, 2008. The Company is currently assessing the potential impact of SFAS No. 157.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, including an amendment to SFAS No. 115. Under SFAS No. 159, entities may elect to measure specified financial instruments and warranty and insurance contracts at fair value on a contract-by-contract basis, with changes in fair value recognized in earnings each reporting period. The election, called the fair value option, will enable entities to achieve an offset accounting effect for changes in fair value of certain related assets and liabilities without having to apply complex hedge accounting provisions. SFAS No. 159 is expected to expand the use of fair value measurement consistent with the FASB s long-term objectives for financial instruments. SFAS No. 159 is effective as of the beginning of a company s first fiscal year that begins after November 15, 2007. The Company is currently evaluating the impact that adoption of SFAS No. 159 will have on its future consolidated financial statements.

In April 2007, the FASB issued Staff Position (FSP) FIN 39-1, *Amendment of FASB Interpretation No. 39.* FSP FIN 39-1 permits an entity to report all derivatives recorded at fair value with any associated fair value cash collateral, which are the same counterparty under a master netting arrangement, together in the balance sheet. Under the provisions of this FSP, the Company must either report all derivatives recorded at fair value net with the associated fair value cash collateral or report all derivative amounts gross. The effects of FSP FIN 39-1 must be applied by adjusting all financial statements presented beginning January 1, 2008. The Company is currently evaluating the impact of this FSP on its financial statements.

Table of Contents

4. ACQUISITIONS

In April 2007, the Company completed the acquisition of certain coalbed methane properties in the Cherokee Basin of Oklahoma and Kansas and interests in certain limited liability companies which own coalbed methane properties in the Cherokee Basin (the EnergyQuest Assets) for approximately $115 million, subject to purchase price adjustments. The Company also completed a private placement of 2,207,684 common units at a price of $26.12 per unit and 90,376 newly-created Class E units at a price of $25.84 per unit for an aggregate purchase price of approximately $60 million. At a special meeting of the common unitholders held on June 26, 2007, the common unitholders approved the conversion of all outstanding Class E units into common units. As a result of the approval, all 90,376 of the Company s outstanding Class E units were cancelled and the same number of common units was issued to the former holders of Class E units. The Company also filed a registration statement with the SEC on July 6, 2007 registering for resale the common units and common units issued upon conversion of the Class E units, which is not yet effective. The proceeds from this equity private placement, together with borrowings under the Company s existing credit facility, fully funded the purchase price of the acquisition. The Company entered into derivative transactions to hedge a portion of the future expected production associated with this acquisition. See Note 5 for a discussion of mark-to-market activities.

The total consideration for the EnergyQuest Assets was $118.0 million, which consisted of cash of $114.8 million and the assumption of an estimated asset retirement obligation of $3.1 million and other miscellaneous liabilities of $0.1 million. The preliminary purchase price allocation of the total consideration of $118.0 million is as follows:

Natural gas and oil properties	$106.1 million
Pipelines	5.7 million
Investment in unconsolidated affiliates	4.0 million
Unproved properties	1.6 million
Other property, plant and equipment	0.5 million
Land	0.1 million
Asset retirement obligation	(3.1 million)
Other miscellaneous liabilities	(0.1 million)
Total	$114.8 million

This preliminary purchase price allocation is based on preliminary appraisals, evaluations of proved oil and natural gas reserves, discounted cash flows, quoted market prices and other estimates by management. The purchase price allocation related to the acquisition of the EnergyQuest Assets is preliminary and subject to change, pending finalization of the valuation of the assets and liabilities acquired.

Pro Forma Results

The unaudited pro forma results presented below for the three and six months ended June 30, 2007 and 2006 have been prepared to give effect to the acquisition of the EnergyQuest Assets described above on our results of operations as if it had been consummated at the beginning of the period presented. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if this acquisition had been completed on such date or to project our results of operations for any future date or period.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(Unaudited) (In 000 s, except per share data)			
Pro forma:				
Revenue	$ 13,052	$ 10,893	$ 25,391	$ 24,864
Income from operations	$ 3,815	$ 2,148	$ 6,913	$ 7,381
Net income	$ 2,722	$ 1,196	$ 4,239	$ 5,379
Basic earnings per share	$ 0.20	$ 0.09	$ 0.31	$ 0.39
Diluted earnings per share	$ 0.20	$ 0.09	$ 0.31	$ 0.39

5. DERIVATIVE AND FINANCIAL INSTRUMENTS

Hedging Activities

The Company has hedged a portion of its expected natural gas sales from currently producing wells through December 2010. The value of the cash flow hedges included in Accumulated other comprehensive income on the Consolidated Balance Sheets was a net unrecognized gain on derivative activities of approximately $9.3 million and $13.3 million at June 30, 2007 and December 31, 2006, respectively. The Company expects that $5.4 million will be reclassified from Accumulated other comprehensive income to the income statement in the next twelve months. There was approximately $0.2 million of income as a result of hedge ineffectiveness for the six months ended June 30, 2007.

At June 30, 2007 and December 31, 2006, the Company had debt outstanding of $82.5 million and $22.0 million, respectively, under its reserve-based credit facility. The Company entered into hedging arrangements in the form of interest rate swaps to reduce the impact of volatility of changes in the London interbank offered rate (LIBOR) on $61.5 million of the outstanding debt through October 2010. The interest rate swaps have termination dates of February 20, 2010 and September 20, 2010, respectively. The swaps have been designated as cash flow hedges of the risk associated with changes in the designated benchmark interest rate (in this case, LIBOR) related to forecasted payments associated with interest on the reserve-based credit facility. The Company has accounted for the interest rate swaps under the long-haul method under SFAS No. 133. There was no hedge ineffectiveness identified. The value of the Company s cash flow hedges included in Accumulated other comprehensive income was a net unrecognized gain of approximately $0.7 million at June 30, 2007 and $0.1 million at December 31, 2006, respectively.

Table of Contents

Mark-to-Market Activities

In March 2007, the Company entered into a combination of swaps and puts in connection with the anticipated acquisition of the EnergyQuest Assets. These derivative positions were accounted for as mark-to-market activities until June 2007, when the swaps were designated as cash flow hedges. The puts continue to be accounted for as mark-to-market activities. For the six months ended June 30, 2007, the Company recognized a net unrealized loss of approximately $5.4 million in connection with these positions. At June 30, 2007, the fair value of the puts was a net asset of approximately $1.2 million.

In March 2007, the Company also entered into a credit support fee agreement with CEG under which CEG will guarantee credit support up to $25.0 million for financial derivatives that the Company entered into with The Royal Bank of Scotland plc (RBS). The guarantee will be in full force until the Company s obligations to RBS under the derivative agreements are secured under its reserve-based credit facility, or March 31, 2008. In March 2007, the Company also entered into a credit support fee agreement with CEG under which CEG will guarantee credit support up to $11.5 million for additional financial derivatives that the Company entered into with BNP Paribas (BNP). The guarantee will be in full force until the Company s obligations to BNP under the derivative agreements are secured under its reserve-based credit facility, or September 30, 2008. The Company paid CEG $0.2 million for the credit supports.

Fair Value of Financial Instruments

The fair value of a financial instrument represents the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Significant differences can occur between the fair value and carrying amount of financial instruments that are recorded at historical amounts. The amounts on the Consolidated Balance Sheets approximate fair value for the following financial instruments because of their short term nature: cash and cash equivalents, accounts receivable, other current assets, current liabilities and deferred credits, natural gas derivative instruments and other liabilities. The Company believes the carrying value of long-term debt approximates its fair value because the fixed interest rates on the debt approximate market interest rates for debt with similar terms.

6. DEBT

Reserve-Based Credit Facility

In October 2006, the Company entered into a $200.0 million secured revolving credit facility with a syndicate of commercial and investment banks, including RBS, as administrative agent. The credit facility will mature on October 31, 2010. The amount available for borrowing at any one time is limited to the borrowing base, which was initially set at $75.0 million, but was increased to $105.0 million on April 5, 2007. The borrowing base will be re-determined semi-annually, and may be re-determined at the Company s request more frequently and by the lenders in their sole discretion based on reserve reports prepared by reserve engineers, together with, among other things, the natural gas and oil prices at such time. Any increase in the borrowing base will have to be approved by all of the lenders in the syndicate and any decrease in the borrowing base will have to be approved by lenders holding at least 66 2/3% of the commitments.

The Company s obligations under the credit facility are secured by mortgages on its natural gas and oil properties, as well as a pledge of all ownership interests in its subsidiaries. The Company was required to maintain the mortgages on properties representing at least 65% of its proved producing and proved non-producing reserves, until the increase in the borrowing base to $180 million, which resulted in the Company s being required to maintain the mortgages on properties representing at least 85% of its proved producing and proved non-producing reserves. Additionally, the obligations under the credit facility are guaranteed by all of its operating subsidiaries and any future material subsidiaries.

At the Company s election, interest will be determined by reference to:

- LIBOR plus an applicable margin between 1.25% and 2.00% per annum based on utilization; or

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

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

The credit facility contains covenants that, among other things, require the Company to maintain, as of the last day of each fiscal quarter, a ratio of Adjusted EBITDA (as defined in the credit agreement) to cash interest expense, each measured for the preceding quarter, of not less than 4.5

to 1.0; a ratio of total indebtedness to Adjusted EBITDA of not more than 3.5 to 1.0; and a ratio of current assets to current liabilities of not less than 1.0 to 1.0. A failure to maintain the foregoing ratios could result in an acceleration of any indebtedness in excess of $1.0 million and would constitute an event of default under the credit facility that would prohibit the Company from making distributions. Debt issue costs incurred through June 30, 2007 were approximately $1.4 million and will be amortized over the life of the facility.

As of June 30, 2007 and December 31, 2006, the Company had $82.5 million and $22.0 million, respectively, in outstanding debt under its reserve-based credit facility.

7. NATURAL GAS PROPERTIES

Natural gas properties consist of the following:

	June 30, 2007	December 31, 2006
	(In 000 s)	
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 304,478	$ 181,747
Unproved property	1,768	88
Total property costs	306,246	181,835
Materials and supplies	546	1,264
Land	202	160
Total	306,994	183,259
Less: Accumulated depreciation, depletion and amortization	(17,126)	(11,620)
Oil and natural gas properties and equipment, net	$ 289,868	$ 171,639

7

Table of Contents

In February 2007, CEP sold a surplus compressor for $0.2 million and recorded a $0.1 million loss on the sale.

8. RELATED PARTY TRANSACTIONS

Prior to the initial public offering, the Company was wholly-owned by CCG. CCG performed various management tasks on behalf of CEP, including the operation and accounting functions. The costs to perform these management tasks were calculated by taking the percentage of time CCG employees were engaged with CEP business multiplied by their annual salary. CCG also processed the payroll and 401(k) transactions on behalf of CEP. These costs charged to CEP were calculated by taking the field employees total salary multiplied by a corporate overhead allocation percentage. Finally, CCG hired outside consultants to augment its current workforce specifically for the management of CEP. The full cost of these consultants was allocated to CEP. These costs totaled approximately $0.5 million for the six months ended June 30, 2006. CEP had a related party payable to CCG of $1.8 million and $2.8 million as of June 30, 2007 and December 31, 2006, respectively. This related party payable balance is included in current liabilities in the accompanying balance sheets.

In November 2006, CEP entered into a management services agreement with Constellation Energy Partners Management, LLC (CEPM) to provide certain management, technical and administrative services. These services include legal, accounting and finance, engineering and technical, risk management, information technology and tax services, as well as acquisition services related to opportunities to acquire oil and natural gas reserves and related midstream assets. CEPM and its affiliates do not have any obligation to provide CEP with acquisition services under the management services agreement, provided that CEPM may receive added compensation for providing CEP with services as a result of the management incentive interests it holds in CEP. These management incentive interests represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in CEP s limited liability company agreement) has been achieved and certain other tests have been met. For the six months ended June 30, 2007, none of these applicable tests have been met, and, as a result, CEPM was not entitled to receive any management incentive interest distributions. CEP reimburses CEPM on a quarterly basis for certain expenses it incurs on CEP s behalf, including certain employee compensation costs. For the six months ended June 30, 2007, $0.7 million in costs were accrued under this agreement.

As described further in Note 5, CEG and CEP entered into credit support fee agreements under which CEG guarantees credit support for certain financial derivatives with two financial institutions. CEP paid CEG $0.2 million for the credit support, which is being amortized over the life of the credit support fee agreements.

During the six months ended June 30, 2006, CCG paid $0.6 million of additional expenses on CEP s behalf in exchange for additional equity in CEP. These expenses included legal fees, fees for consultants hired by CEP and various other expenses.

In February 2006, CEP entered into a cash pool arrangement with CCG. This cash pool arrangement was administered and managed by CEP. CCG could borrow from the pool at market interest rates. If CEP required cash, and CCG had an outstanding balance, CCG was required to immediately remit payment to CEP for the required cash amount. Upon the completion of its initial public offering, CEP ceased its participation in the cash pool arrangement and CCG retained the $12.4 million receivable balance. This was treated as a reduction of members equity for accounting purposes.

9. COMMITMENTS AND CONTINGENCIES

In the course of its normal business affairs, the Company is subject to possible loss contingencies arising from federal, state and local environmental, health and safety laws and regulations and third-party litigation. As of June 30, 2007 and December 31, 2006, other than the matter discussed below, there were no matters which, in the opinion of management, would have a material adverse effect on the financial position, results of operations or cash flows of CEP.

Certain of the Robinson s Bend Assets are subject to a net profits interest (NPI) held by Torch Energy Royalty Trust (the Trust) (See Note 11). The royalty payment to the Trust is calculated using a sharing arrangement with a pricing formula that has been below market and has had the effect of keeping CEP s payments to the Trust lower than if such payments had been calculated based on prevailing market prices. If the sharing agreement were to terminate, CEP s payments to the Trust could increase and CEP s revenue could decrease, in each case compared to the amounts if the sharing arrangement remained in effect. CEP is uncertain of the financial impact of the NPI over the life of the Robinson s Bend Field as it has volumetric and price risk variables. However, in order to address a portion of the risk of the potential adverse impact on CEP s operating results from a termination of the sharing arrangement, CHI contributed $8.0 million to CEP in exchange for all of CEP s Class D interests at the closing of its initial public offering, to be used to protect the distributions to the common unit holders in the event the sharing arrangement is terminated. This contribution will be returned to CHI in 24 special quarterly distributions as long as the sharing agreement remains in effect for the distribution period. A distribution of $333,333 was paid to the holder of the Company s Class D interests on May 15, 2007. A distribution of $333,333 will also be paid to the holder of the Company s Class D interests on August 14, 2007.

On May 10, 2007, a group of investors, 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. 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. Although the group of investors did not acquire 66 2/3% of the outstanding Trust units, they may seek to terminate the Trust by calling a meeting for the purpose of voting on the termination of 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. See Note 11 for further discussion regarding the gas purchase contract. See Note 15 for further discussion relating to an effort to terminate the Trust.

For CEP s 2007 drilling program, CEP has committed to purchase approximately $1.0 million in pipe from a vendor. As of June 30, 2007, CEP had purchased approximately $0.8 million of pipe related to this commitment.

10. ASSET RETIREMENT OBLIGATION

The Company follows SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation (ARO) be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost (ARC) is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the ARC is allocated to expense using a systematic and rational method over the asset s useful life. The ARO recorded by CEP relates to the plugging and abandonment of natural gas wells, and decommissioning of the gas gathering and processing facilities.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO, a corresponding adjustment is made to the gas property balance.

Table of Contents

The following table is a reconciliation of the ARO:

	June 30, 2007	December 31, 2006
	(In 000 s)	
Asset retirement obligation, beginning balance	$ 2,730	$ 2,524
Obligation assumed in acquisition (Note 7)	3,049	
Liabilities incurred	41	65
Accretion expense	113	141
Asset retirement obligation, ending balance	$ 5,933	$ 2,730

At June 30, 2007 and December 31, 2006, there were no assets legally restricted for purposes of settling existing ARO s. Additional retirement obligations increase the liability associated with new natural gas wells and other facilities as these obligations are incurred.

11. NET PROFITS INTEREST

Certain of the Robinson s Bend Assets are subject to a non-operating NPI. The holder of the NPI, the Trust, does not have the right to receive production from the Robinson s Bend Assets. Instead, the Trust only has the right to receive a specified portion of the future contractual cash flows from specified wells as defined by the Net Overriding Royalty Conveyance Agreement. The Company records the NPI as an overriding royalty interest net in revenue in the Consolidated Statements of Operations.

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

The Net Proceeds equal the lesser of (i) 95% of the net proceeds from 393 producing wells in the Robinson s Bend Field and (ii) the net proceeds from the sale of 912.5 MMcf of natural gas for the quarter. Net proceeds equal gross proceeds, currently calculated by reference to the gas purchase contract (for a description of the gas purchase contract, please read Item 1. Business Natural Gas Data Torch Royalty NPI The Gas Purchase Contract in the Company s Annual Report on Form 10-K for the year ended December 31, 2006), less specified costs attributable to the Robinson s Bend Assets. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (i) of the first sentence of this paragraph (the NPI Net Proceeds Calculation) include: (a) delay rentals, shut-in royalties and similar payments, (b) property, production, severance and similar taxes and related audit charges, (c) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies, (d) certain liabilities for environmental damage, personal injury and property damage, (e) certain litigation costs, (f) costs of environmental compliance, (g) specified operating costs incurred to produce hydrocarbons, (h) specified development costs (including costs to increase recoverable reserves or the timing of recovery of such reserves), (i) costs of specified lease renewals and extensions and unitization costs and (j) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (ii) of the first sentence of this paragraph include: (a) property, production, severance and similar taxes, (b) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies and (c) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. Net proceeds are calculated quarterly and any negative balance (expenses in excess of revenues) within the net proceeds calculation accumulates and is charged interest as described above.

The cumulative Net NPI Proceeds balance must be greater than $0 before any payments are made to the Trust. The cumulative Net Proceeds was a deficit for the six months ended June 30, 2007. As a result, no payments have been made to the Trust with respect to the NPI in 2007. With respect to production for the six months ended June 30, 2006, CEP paid the Trust a total of $0.2 million.

The calculation of the Infill Net Proceeds uses the same methodology as the NPI Net Proceeds Calculation described above except that the proceeds and costs are attributable not to the NPI Net Proceeds Wells, but to the remaining wells in the Robinson s Bend Field that are subject to the NPI and that have been drilled since the Trust was formed and wells that will be drilled (other than wells drilled to replace damaged or destroyed wells), in each case on leases subject to the NPI. The NPI in the Infill Wells entitles the Trust to receive 20% of the Infill Net Proceeds. There has never been a payout on the Infill Net Proceeds.

12. ENVIRONMENTAL LIABILITY

The Company is subject to costs resulting from an increasing number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. As of June 30, 2007 and December 31, 2006, accrued environmental obligations were $0.7 million, which were classified as current on CEP s balance sheet.

13. DISTRIBUTIONS TO UNITHOLDERS

On February 14, 2007, the Company paid a distribution for the fourth quarter of 2006 to the unitholders of record at February 7, 2007, prorated from the date of the Company s initial public offering on November 20, 2006. The distribution was paid to holders of common units and Class A units at a rate of $0.2111 per unit.

On May 15, 2007, the Company paid a distribution for the first quarter of 2007 to the unitholders of record at May 8, 2007. The distribution was paid to holders of common units, Class A units and Class E units at a rate of $0.4625 per unit.

A distribution of $333,333 was paid to the holder of the Company s Class D interests on May 15, 2007.

On July 24, 2007, the Company declared a distribution for the second quarter of 2007 to the unitholders of record at August 7, 2007. The distribution will be paid to holders of common units and Class A units at a rate of $0.4625 per unit. The distribution will not be paid to holders of Class F units or to the holders of common units issued in connection with the Amvest Acquisition. The distribution will be paid on August 14, 2007. See Note 15 for a discussion of the Amvest Acquisition.

A distribution of $333,333 will also be paid to the holder of the Company s Class D interests on August 14, 2007.

Table of Contents

14. CONVERSION OF CLASS E UNITS

At a special meeting of the Company s common unitholders held on June 26, 2007, the common unitholders approved the conversion of all outstanding Class E units into common units. As a result of the approval, all 90,376 of the Company s outstanding Class E units were cancelled and the same number of common units was issued to the former holders of Class E units.

15. SUBSEQUENT EVENTS

Equity Issuance Associated with the Amvest Acquisition

On July 25, 2007, the Company issued an additional 2,664,998 common units and 3,371,219 newly-created Class F units to third party investors in a private placement for aggregate proceeds of approximately $210 million. As a result of this issuance, affiliates of CCG own approximately 32% of the outstanding limited liability company interests of CEP.

Amvest Acquisition

In July 2007, the Company completed the acquisition of additional oil and natural gas properties in the Cherokee Basin of Oklahoma (the Amvest Acquisition) for approximately $240 million, subject to purchase price adjustments. The Company 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 for an aggregate purchase price of approximately $210 million. The Class F units will convert into common units, on a one-for-one basis, upon obtaining common unit holder approval. The Company has undertaken to obtain this approval by October 23, 2007. The Company also agreed to file a registration statement with the 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 the Company s existing credit facility, fully funded the purchase price of the acquisition. Subsequent to June 30, 2007, the Company 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.

Newfield Acquisition Announcement

In August 2007, the Company announced that it had entered into a definitive purchase agreement to acquire additional coalbed methane properties in the Cherokee Basin of Oklahoma (the Newfield Assets) for approximately $128 million, subject to purchase price adjustments. The Company executed a unit purchase agreement with third party investors to sell 2,470,592 common units at a price of $42.50 per unit in a private placement for an aggregate purchase price of approximately $105 million. The Company has agreed to file a registration statement with the SEC registering for resale the common units within 90 days after the closing of the private placement. The Company believes that the proceeds from this equity private placement, together with funds available under its existing credit facility, will fully fund the purchase price of the acquisition. The Company anticipates that the private placement will close simultaneously with the acquisition of the assets in September 2007. The Company borrowed $13.0 million under its reserve-based credit facility to fund an acquisition deposit escrow account. The Company also entered into derivative transactions to hedge the future expected production associated with this acquisition. Upon the issuance of the equity securities, affiliates of CCG will own approximately 28% of the outstanding limited liability company interests of CEP.

Debt

In July 2007, we borrowed $42.5 million under the Company s reserve-based credit facility to fund the purchase price of the Amvest Acquisition, as well as to fund planned capital expenditures on these properties. On July 6, 2007, the borrowing of the reserve-based credit facility was increased to $135.0 million, and then to $180.0 million on July 26, 2007. In August 2007, we borrowed an additional $13.0 million to fund an acquisition deposit escrow account for the purchase of the Newfield Assets.

In July 2007, the amount guaranteed under the credit support fee agreement with CEG, under which CEG will guarantee credit support for the Company s financial derivatives, was increased to $15.0 million. This guarantee and the guarantee for $25.0 million were released effective July 6, 2007, when the borrowing base under the Company s reserve-based credit facility was increased to $135.0 million. On July 13, 2007, the Company entered into a credit support fee agreement with CEG under which CEG will guarantee credit support up to $15.0 million for financial derivatives that the Company entered into in relation to the Amvest Acquisition. This guarantee was released on July 26, 2007, when the borrowing base under the Company s reserve-based credit facility was increased to $180.0 million. On August 3, 2007, the Company entered into a credit support fee agreement with CEG under which CEG will guarantee credit support up to $10.0 million for financial derivatives that the Company entered into in anticipation of the acquisition of the Newfield Assets.

Torch Energy Royalty Trust

In August 2007, 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 and that the Trust is in the processes of preparing the notice of such special meeting which will include the time and place thereof. See Note 9.

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with the financial statements and the summary of significant accounting policies and notes included herein and in the Company s most recent Annual Report on Form 10-K.

Overview

We are a limited liability company formed by Constellation Energy Group, Inc. (Constellation) on February 7, 2005 to acquire oil and natural gas properties (E&P properties) as well as related midstream assets. At June 30, 2007, our estimated proved reserves consist of oil and natural gas and were located in the Robinson s Bend Field in Alabama s Black Warrior Basin and in the Cherokee Basin of Oklahoma and Kansas. Our primary business objective is to generate stable cash flows allowing us to make quarterly cash distributions to our unitholders and over time to increase the amount of our future quarterly distributions. Our strategies for achieving this objective are to:

- 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.

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

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

In April 2007, we completed an acquisition of coalbed methane properties located in the Cherokee Basin in Kansas and Oklahoma (the EnergyQuest Assets). In July 2007, we completed an acquisition of additional oil and natural gas properties located in the Cherokee Basin in Oklahoma (the Amvest Acquisition). In August 2007, we announced that we had entered into a definitive purchase agreement to acquire additional coalbed methane properties in the Cherokee Basin of Oklahoma (the Newfield Assets). These acquisitions are discussed in more detail in Notes 3 and 15 to our consolidated financial statements.

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

How We Evaluate our Operations

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

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

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

Table of Contents

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

	For the Three Months Ended June 30, 2007	For the Three Months Ended June 30, 2006	For the Six Months Ended June 30, 2007	For the Six Months Ended June 30, 2006
	(In 000 s)			
Reconciliation of Net Income to Adjusted EBITDA:				
Net income	$ 2,193	$ 2,353	$ 4,447	$ 6,785
Adjusted by:				
Interest expense (income), net	1,182	(148)	1,690	(197)
Depreciation, depletion and amortization	3,584	2,066	5,543	3,811
Accretion of asset retirement obligation	77	35	113	71
Loss (gain) on sale of asset	(1)		94	
Loss on mark-to-market activities	2,619		5,401	
Unrealized gain on natural gas derivatives	223		(174)	
Adjusted EBITDA	$ 9,877	$ 4,306	$ 17,114	$ 10,470

Significant Operational Factors since December 31, 2006

Realized Prices. Our average realized price for the six months ended June 30, 2007, including hedges, was $6.98 per Mcf. This realized price includes the impact of $5.4 million of losses on mark-to-market derivatives that were entered into in anticipation of closing our acquisition of additional coalbed methane properties in Kansas and Oklahoma. Excluding the impact of the mark-to-market losses, the average realized price for the six months ended June 30, 2007 was $8.77 per Mcf.

Production. Our production during the first six months of 2007 was 3.0 Bcf, or an average of 16,702 Mcf per day. Our June 2007 production was approximately 21,922 Mcf per day.

Capital Expenditures and Drilling Results. For the six months ended June 30, 2007, we incurred $10.1 million in capital expenditures. We accelerated our drilling program in the Robinson s Bend Field and have drilled and completed 20 wells with a 100% drilling success rate. We have also drilled 22 net wells in the Cherokee Basin, with eight net wells currently online at June 30, 2007. We also performed three recompletions in the Cherokee Basin as of June 30, 2007. Initial production from these newly drilled wells was in line with expectations.

Operating Expenses. Operating expenses were up 58% from the second quarter of 2006, reflecting the addition of the Cherokee Basin assets, as well as acquisition and integration related costs of approximately $0.3 million. Lease operating expenses in the Cherokee Basin were up somewhat from expectations as a result of increased costs due to weather and associated maintenance.

In November 2006, we entered into a management services agreement with a subsidiary of Constellation to provide us with certain management, technical and administrative services. These services include legal, accounting and finance, engineering and technical, risk management, information technology, and tax services, as well as acquisition services related to opportunities to acquire oil and natural gas reserves and related midstream assets. The fees for services under the agreement will be determined on an annual basis and will be based on Constellation s cost to provide the services. The payments to Constellation are due quarterly.

Pursuant to the agreement, we are required to use CEPM or its designee for legal, accounting, finance, tax and risk management services through December 31, 2007. Constellation does not have any obligation to provide us with acquisition services under the management services agreement, but 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.

Acquisitions. We have completed or announced three complementary coalbed methane acquisitions.

EnergyQuest Acquisition

In April 2007, we completed the acquisition of the EnergyQuest Assets and interests in certain limited liability companies which own coalbed methane properties in the Cherokee Basin for approximately $115 million, subject to purchase price adjustments. We also completed a private placement of 2,207,684 common units at a price of $26.12 per unit and 90,376 newly-created Class E units at a price of $25.84 per unit for an aggregate purchase price of approximately $60 million. At a special meeting of the common unitholders held on June 26, 2007, the common unitholders approved the conversion of all outstanding Class E units into common units. As a result of the approval, all 90,376 of our outstanding Class E units were cancelled and the same number of common units was issued to the former holders of Class E units. We also filed a registration statement with the SEC on July 6, 2007, registering for resale the common units and common units issued upon conversion of the Class E units. The proceeds from this equity private placement, together with borrowings under our existing credit facility, fully funded the purchase price of the acquisition. We entered into derivative transactions to hedge a portion of the future expected production associated with this acquisition.

Amvest Acquisition

In July 2007, we completed 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 in a private placement for an aggregate purchase price of approximately $210 million. The Class F units will convert into common units, on a one-for-one basis, upon obtaining common unit holder approval. We have undertaken to obtain this approval by October 23, 2007. We also agreed to file a registration statement with the 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. Subsequent to June 30, 2007, we entered into derivative transactions to hedge a portion of the future expected production associated with this acquisition and borrowed $33.5 million under our reserve-based credit facility, along with $1.0 million of cash on hand, to fund the acquisition.

Table of Contents

Newfield Acquisition

In August 2007, we announced that we have entered into a definitive purchase agreement to acquire additional coalbed methane properties in the Cherokee Basin of Oklahoma for approximately $128 million, subject to purchase price adjustments. We executed a unit purchase agreement with third party investors to sell 2,470,592 common units at a price of $42.50 per unit in a private placement for an aggregate purchase price of approximately $105 million. We have also agreed to file a registration statement with the SEC registering for resale the common units within 90 days after the closing of the private placement. We believe that the proceeds from this equity private placement, together with funds available under our existing credit facility, will fully fund the purchase price of the acquisition. We anticipate that the private placement will close simultaneously with the acquisition of the assets in September. We borrowed $13.0 million under our reserve-based credit facility to fund an acquisition escrow account. We also entered into derivative transactions to hedge the future expected production associated with this acquisition.

Oklahoma and Kansas Flooding. In July 2007, there was record flooding in Oklahoma and Kansas, which impacted our drilling and production in the Cherokee Basin. We estimate that production has been decreased by approximately 400 Mcf per day. The Verdigris River crossing was washed out, which impacted our production through July 16, 2007 by approximately 800 Mcf per day, as some of our wells were not accessible until the crossing was replaced. Our field office in the Cherokee Basin was also flooded and sustained minor damage. We estimate that we will incur approximately $125,000 in repair and replacement costs as a result of the flooding.

Hedging Activities. We have implemented a hedging program that uses derivatives to reduce the impact of commodity price volatility on our anticipated cash flows. Our current intention is to hedge approximately 80% of our forecasted production for a five year period. Our management, however, may modify the hedging percentages and strategies as it deems appropriate for market conditions and other business strategies. For 2007, we have hedged 4,199,996 MMBtu of our projected production for the Robinson s Bend Field at a weighted average price of $9.19 per MMBtu.

In conjunction with the purchase of the EnergyQuest Assets, we entered into derivative transactions to hedge certain of the future expected production associated with this acquisition. These derivatives were accounted for using mark-to-market accounting until June 2007, resulting in an unrealized loss of approximately $5.4 million. On June 18, 2007, we designated the swaps related to the projected production for the Cherokee Basin. The swaps are now being accounted for as hedges using cash flow hedge accounting, while the put options continue to be accounted for using the mark-to-market accounting method. For 2007, we have hedged 1,750,000 MMBtu of our projected production for the EnergyQuest Assets under these swaps at a weighted average price of $7.82 per MMBtu.

In conjunction with the purchase of the Amvest Acquisition and the anticipated acquisition of the Newfield Assets, we entered into derivative transactions to hedge certain of the future expected production associated with these acquisitions. These derivatives are being accounted for using mark-to-market accounting.

Debt. The initial borrowing base of our reserve-based credit facility was set at $75.0 million, but was increased to $105.0 million on April 5, 2007, and then increased to $180.0 million on July 26, 2007. The credit facility will mature in October 2010. As of June 30, 2007, we had $82.5 million in outstanding debt under our reserve-based credit facility. In July 2007, we borrowed $42.5 million to fund the purchase price of the Amvest Acquisition, as well as to fund planned capital expenditures on these properties. In August 2007, we borrowed an additional $13.0 million to fund an acquisition deposit escrow account for the purchase of the Newfield Assets. As of August 7, 2007, we have $138.0 million outstanding under our secured revolving credit facility.

Table of Contents

Results of Operations

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

	For the Three Months Ended				For the Six Months Ended			
	June 30, 2007	June 30, 2006	Variance $	Variance %	June 30, 2007	June 30, 2006	Variance $	Variance %
	(In 000 s, except production, cost and price data)							
Revenues:								
Oil and gas sales	$ 15,190	$ 7,858	$ 7,332	93.3%	$ 26,497	$ 17,605	$ 8,892	50.5%
Loss from mark-to-market activities	(2,619)		(2,619)	(100.0)%	(5,401)		(5,401)	(100.0)%
Total revenues	12,571	7,858	4,713	60.0%	21,096	17,605	3,491	19.8%
Operating expenses:								
Lease operating expenses	3,150	1,583	1,567	99.0%	4,745	3,495	1,250	35.8%
Production taxes	685	333	352	105.7%	1,144	909	235	25.9%
General and administrative expenses	1,771	1,636	135	8.3%	3,390	2,731	659	24.1%
Loss (gain) on sale of asset	(1)		(1)	(100.0)%	94		94	100.0%
Depreciation, depletion and amortization	3,584	2,066	1,518	73.5%	5,543	3,811	1,732	45.4%
Accretion expenses	77	35	42	120.0%	113	71	42	59.2%
Total operating expenses	9,266	5,653	3,613	63.9%	15,029	11,017	4,012	36.4%
Other expenses (income):								
Interest expense	1,266	1	1,265	1,265.0%	1,825	1	1,824	1,824.0%
Interest income	(84)	(149)	65	(43.6)%	(135)	(198)	63	(31.8)%
Other	(70)		(70)	(100.0)%	(70)		(70)	(100.0)%
Total other expenses (income)	1,112	(148)	1,260	(851.4)%	1,620	(197)	1,817	(922.3)
Total expenses	10,378	5,505	4,873	88.5%	16,649	10,820	5,829	53.9%
Net income	$ 2,193	$ 2,353	$ (160)	(6.8)%	$ 4,447	$ 6,785	$ (2,338)	(34.5)%
Net production:								
Total production (MMcf)	1,796	1,090	706	64.8%	3,023	2,200	823	37.4%
Average daily production (Mcf/d)	19,736	11,978	7,758	64.8%	16,702	12,155	4,547	37.4%
Average sales prices:								
Price per Mcf including hedges	$ 7.00(a)	$ 7.21	$ (0.21)	(2.9)%	$ 6.98(a)	$ 8.00	$ (1.02)	(12.8)%
Price per Mcf excluding hedges	$ 7.44	$ 7.21	$ 0.23	3.2%	$ 7.25	$ 8.00	$ (0.75)	(9.4)%
Average unit costs per Mcf:								
Field operating expenses(b)	$ 2.13	$ 1.76	$ 0.37	21.0%	$ 1.95	$ 2.00	$ (0.05)	(2.5)%
Lease operating expenses	$ 1.75	$ 1.45	$ 0.30	20.7%	$ 1.57	$ 1.59	$ (0.02)	(1.3)%
Production taxes	$ 0.38	$ 0.31	$ 0.07	22.6%	$ 0.38	$ 0.41	$ (0.03)	(7.3)%
General and administrative expenses	$ 0.99	$ 1.50	$ (0.51)	(34.0)%	$ 1.12	$ 1.24	$ (0.12)	(9.7)%
Depreciation, depletion and amortization	$ 2.00	$ 1.90	$ 0.10	5.3%	$ 1.83	$ 1.73	$ 0.10	5.8%

(a) Includes the impact of mark-to-market losses on derivatives that do not qualify for cash flow hedging.

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

Three months ended June 30, 2007 compared to the three months ended June 30, 2006

Oil and gas sales. Oil and natural gas sales increased $7.3 million, or 93.3%, to $15.2 million for the three months ended June 30, 2007. Of this increase, $5.1 million was attributable to increased production volumes and $1.3 million was attributable to our hedge program which was implemented subsequent to June 2006, offset by the impact of lower market prices for natural gas. Production for the three months ended June 30, 2007 was 1.8 Bcf, which was higher than the three months ended June 30, 2006 as a result of our drilling program and operational improvements, along with the acquisition of our properties in the Cherokee Basin. We hedged approximately 96% of our actual production from April 2007 through June 2007. Our realized prices declined from 2006 to 2007 because of lower natural gas prices and the impact of our mark-to-market activities described below.

Hedging and mark-to-market activities. We did not have any mark-to-market derivatives for the three months ended June 30, 2006. However, in conjunction with the purchase of the EnergyQuest Assets, we entered into derivative transactions to hedge a portion of the future expected production associated with this acquisition, before the acquisition was closed. These derivatives were accounted for as mark-to-market derivatives and were recorded at fair value in our financial statements until June 18, 2007, at which time the swaps were designated as cash flow hedges and began receiving cash flow accounting treatment. For the quarter ended June 30, 2007, the unrealized mark-to-market loss was $2.6 million.

We entered into cash flow hedges beginning in October 2006 in an effort to reduce our exposure to short-term fluctuations in natural gas prices. For the three months ended June 30, 2007, we recognized expense of approximately $0.2 million related to hedge ineffectiveness.

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

For the three months ended June 30, 2007, field operating expenses increased $1.9 million, or 100.2%, to $3.8 million, compared to expenses of $1.9 million for the three months ended June 30, 2006. This increase was primarily the result of the costs of operating the EnergyQuest Assets. In June 2007, Oklahoma and Kansas received record amounts of rainfall. This resulted in increased operating expenses due to weather and associated maintenance and repairs.

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

Table of Contents

General and administrative expenses increased $0.1 million, or 8.3%, to $1.8 million for the three months ended June 30, 2007, as compared to the three months ended June 30, 2006. This increase was primarily due to $0.3 million in expenses related to acquisition and integration costs associated with our recent acquisitions, $0.1 million in expenses related to the Constellation credit support fee, and expenses related to the management services agreement, under which CEPM bills us for services and costs incurred on our behalf. In the second quarter of 2007, CEPM allocated $0.4 million in expenses to us for labor and other charges.

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

Our depreciation, depletion and amortization expense for the three months ended June 30, 2007 was $3.6 million, or $2.00 per Mcf, compared to $2.1 million, or $1.90 per Mcf, for the three months ended June 30, 2006. This increase reflects the increased basis in our assets resulting from additional capital expenditures and asset acquisitions between June 30, 2006 and June 30, 2007. As described above, we calculate depletion using units-of-production under the successful efforts method of accounting.

Interest expense. Interest expense for the three months ended June 30, 2007 increased $1.3 million as compared to the three months ended June 30, 2006. This increase was due to the borrowings under our reserve-based credit facility, which we entered into on October 31, 2006. At June 30, 2007, we had an outstanding balance under the credit facility of $82.5 million. Interest expense was partially offset by $0.1 million of gain realized on an interest rate swap that was terminated in June 2007.

Interest income. Interest income was $0.1 million for the three months ended June 30, 2007 and for the three months ended June 30, 2006. During the three months ended June 30, 2007, we earned interest income by utilizing overnight investments on our excess cash balances. In 2006, our interest income was earned on our cash pool arrangement with CCG. As of November 2006, we ceased participation in the cash pool arrangement.

Six months ended June 30, 2007 compared to the six months ended June 30, 2006

Oil and gas sales. Oil and natural gas sales increased $8.9 million, or 50.5%, to $26.5 million for the six months ended June 30, 2007. Of this increase, $6.6 million was attributable to increased production volumes and $2.3 million was attributable to our hedge program, offset by the impact of lower market prices for natural gas. Production for the six months ended June 30, 2007 was 3.0 Bcf, which was higher than the six months ended June 30, 2006 as a result of our drilling program and operational improvements, along with the acquisition of the EnergyQuest Assets. We hedged approximately 90% of our actual production through June 2007. Our realized prices declined from 2006 to 2007 because of lower natural gas prices and the impact of our mark-to-market activities described below.

Hedging and mark-to-market activities. We did not have any mark-to-market derivatives for the six months ended June 30, 2006. However, in conjunction with the purchase of the EnergyQuest Assets, we entered into derivative transactions to hedge a portion of the future expected production associated with this acquisition, before the acquisition was closed. These derivatives were accounted for as mark-to-market derivatives and were recorded at fair value in our financial statements until June 18, 2007, at which time the swaps were designated as cash flow hedges. For the six months ended June 30, 2007, the unrealized mark-to-market loss was $5.4 million. The put options related to the production from the EnergyQuest Assets will continue to be accounted for using the mark-to-market method of accounting.

We entered into cash flow hedges beginning in October 2006 in an effort to reduce our exposure to short-term fluctuations in natural gas prices. For the six months ended June 30, 2007, we recognized income of approximately $0.2 million related to hedge ineffectiveness.

Field operating expenses. For the six months ended June 30, 2007, field operating expenses increased $1.5 million, or 33.7%, to $5.9 million, compared to expenses of $4.4 million for the six months ended June 30, 2006. This increase was primarily the result of maintenance costs in the Robinson s Bend Field during the six months ended June 30, 2007, along with the costs of operating the EnergyQuest Assets. Our per unit costs decreased from $2.00 per Mcf in 2006 to $1.95 per Mcf in 2007 because of operational efficiencies gained during the year and higher production volumes.

General and administrative expenses. General and administrative expenses increased $0.7 million, or 24.1%, to $3.4 million for the six months ended June 30, 2007, as compared to the six months ended June 30, 2006. This increase was primarily due to the increased expenses related to being a public company, expenses related to acquisition and integration costs associated with our recent acquisition, $0.1 million in expenses related to the Constellation credit support fee, and expenses related to the management services agreement, under which CEPM bills us for services and costs incurred on our behalf.

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

Depreciation, depletion and amortization expense. Our depreciation, depletion and amortization expense for the six months ended June 30, 2007 was $5.5 million, or $1.83 per Mcf, compared to $3.8 million, or $1.73 per Mcf, for the six months ended June 30, 2006. This increase reflects the increased basis in our assets resulting from additional capital expenditures between June 30, 2006 and June 30, 2007. As described above, we calculate depletion using units-of-production under the successful efforts method of accounting.

Interest expense. Interest expense for the six months ended June 30, 2007 increased $1.8 million as compared to the six months ended June 30, 2006. This increase was due to the borrowings under our reserve-based credit facility, which we entered into on October 31, 2006. At June 30, 2007, we had an outstanding balance under the credit facility of $82.5 million. Interest expense was partially offset by $0.1 million of gain realized on an interest rate swap that was terminated in June 2007.

Interest income. Interest income was $0.1 million for the six months ended June 30, 2007, compared to $0.2 million for the six months ended June 30, 2006. During the six months ended June 30, 2007, we earned interest income by utilizing overnight investments on our excess cash balances. In 2006, our interest income was earned on our cash pool arrangement with CCG. As of November 2006, we ceased participation in the cash pool arrangement.

Accumulated other comprehensive income. Accumulated other comprehensive income, shown on our consolidated balance sheets, reflects the changes in the fair market value of our open hedge positions. At June 30, 2007, the balance was $9.5 million compared to a balance of $13.1 million at December 31, 2006. This decrease reflects an increase in the market prices for natural gas. The decrease is shown in our consolidated statements of operations and comprehensive income as a gain of $6.2 million for the three months ended June 30, 2007, and as a loss of $3.6 million for the six months ended June 30, 2007.

Liquidity and Capital Resources

During the six months ended June 30, 2007, we utilized proceeds from credit facility borrowings, equity financing and cash flow from operations as our primary sources of capital. As of June 30, 2007, our primary use of capital has been for the development of existing oil and natural gas properties and the acquisition of additional oil and natural gas properties. As we pursue our growth strategy, we will be monitoring the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in growing reserves and production will be highly dependent on the capital resources available to us and our success in drilling for or acquiring additional reserves. Based upon our current expectations, we expect to continue to generate cash flow sufficient to support our projected maintenance capital expenditures and operations of our business.

In addition, our reserve-based credit facility may be used to help finance future expansion capital expenditures, such as drilling and recompletions beyond that required to maintain production, as well as acquisitions. At June 30, 2007, we had $82.5 million of debt outstanding under the reserve-based credit facility and $22.5 million in unused borrowing capacity. On July 26, 2007, our borrowing base was increased to $180.0 million. Subsequent to this increase in our borrowing base, we borrowed $42.5 million to fund a portion of the $240.0 million purchase price associated with the purchase of the Amvest Acquisition and investment capital expenditures. To fully fund the purchase price in July 2007, we relied on the issuance of $210 million of additional common units and Class F units in a private placement to third party investors and borrowed the remaining balance under our reserve-based credit facility. In August 2007, we borrowed an additional $13.0 million to fund an acquisition deposit escrow account for the purchase of the Newfield Assets. As of August 7, 2007, we have $138.0 million outstanding under our secured revolving credit facility.

In each of the next two years, we expect to utilize our cash flow from operations and borrowings under our reserve-based credit facility to fund a portion of our drilling expenditures. We expect to fund our remaining 2007 and 2008 maintenance capital expenditures with cash flow from operations, while funding our 2007 and 2008 investment capital expenditures and any expansion capital expenditures that we might incur with borrowings under our reserve-based credit facility and issuances of additional units. We estimate that we will have sufficient cash flow from operations after funding our acquisitions and our maintenance capital expenditures to enable us to make our quarterly cash distributions to unitholders through December 31, 2008. CEPM currently holds management incentive interests in us that represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in our limited liability company agreement) has been achieved and certain other tests have been met. The earliest that we could be required to make distributions in respect of the management incentive interests is after a period of twelve consecutive quarters following our initial public offering. We are not able to predict whether we will be required to make distributions in respect of the management incentive interests or, if we do make such distributions in the future, how much they will be.

In the event the cost of acquiring additional oil or natural gas properties exceeds our existing capital resources, we expect that we will finance those acquisitions with a combination of expanded or new debt facilities or new equity issuances. The ratio of debt and equity issued will be determined by our management and our board of managers.

Reserve-Based Credit Facility

On October 31, 2006, we entered into a $200.0 million secured credit facility with a syndicate of commercial and investment banks, including The Royal Bank of Scotland plc, as administrative agent. The credit facility will mature on October 31, 2010. The amount available for borrowing at any one time is limited to the borrowing base, which was initially set at $75.0 million, but was subsequently increased to $105.0 million, on April 5, 2007. On July 26, 2007, the borrowing base was again increased to $180.0 million. The borrowing base will be re-determined semi-annually, and may be re-determined at our request more frequently and by the lenders in their sole discretion based on reserve reports prepared by our reserve engineers, together with, among other things, the natural gas and oil prices at such time. Any increase in the borrowing base will have to be approved by all of the lenders in the syndicate and any decrease in the borrowing base will have to be approved by lenders holding at least 66 2/3% of the commitments.

Our obligations under the credit facility are secured by mortgages on our natural gas properties, as well as a pledge of all ownership interests in our subsidiaries. With the increased borrowing base, we are required to maintain the mortgages on properties representing at least 85% of our proved producing and proved non-producing reserves. Additionally, the obligations under the credit facility are guaranteed by all of our operating subsidiaries and any future material subsidiaries.

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

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

- LIBOR plus an applicable margin between 1.25% and 2.00% per annum based on utilization; or

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

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

The credit facility contains various covenants that limit our ability to:

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

The credit facility also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- debt to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets, (gain) loss on sale of assets, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on natural gas derivatives and realized (gain) loss on cancelled natural gas derivatives, and other similar charges) of not more than 3.5 to 1.0; and
- Adjusted EBITDA to cash interest expense of not less than 4.5 to 1.0; and
- consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities, of not less than 1.0 to 1.0, all calculated pursuant to the requirements under Statement of Financial Accounting Standards (SFAS) No. 133 and SFAS No. 143 (including the current liabilities in respect of the termination of natural gas and interest rate swaps).

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

Table of Contents

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

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

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

At June 30, 2007, we believe that we are in compliance with the debt covenants contained in our credit facility.

We enter into hedging arrangements to reduce the impact of volatility of changes in the LIBOR interest rate on our interest payments for our reserve-based credit facility. Currently, we have outstanding interest rate swaps that fix our LIBOR rate at 4.74% and 4.964% on $16.5 million and $45.0 million, respectively, of our outstanding debt through February 20, 2010 and September 20, 2010, respectively.

Cash Flow from Operations

Our net cash flow provided by operating activities for the six months ended June 30, 2007 was $15.8 million, compared to net cash flow provided by operating activities of $8.8 million for the same period in 2006. This increase in operating cash flow was primarily attributable to an unrealized loss from mark-to-market activities, along with depreciation, depletion and amortization of approximately $5.5 million during the six months ended June 30, 2007, compared to approximately $3.8 million during the six months ended June 30, 2006.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil and natural gas prices. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through our production, development and exploitation program and acquisitions, as well as the prices of natural gas and the extent and effectiveness of our hedging program.

We enter into hedging arrangements to reduce the impact of natural gas price volatility on our operations. By removing the price volatility from a significant portion of our natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. We do not post collateral under any of these agreements as they are secured under our reserve-based credit facility or guaranteed by Constellation.

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 June 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		$		$	1,644,999	$ 8.69	1,684,999	$ 8.75	3,329,998	$ 8.72
2008	1,475,001	$ 8.68	1,415,001	$ 8.66	1,415,001	$ 8.66	1,415,001	$ 8.66	5,720,004	$ 8.67
2009	1,275,000	$ 8.27	1,275,000	$ 8.27	1,275,000	$ 8.27	1,275,000	$ 8.27	5,100,000	$ 8.27
2010	540,000	$ 7.75	540,000	$ 7.75	540,000	$ 7.75	540,000	$ 7.75	2,160,000	$ 7.75
									16,310,002	

Table of Contents

Our derivative positions accounted for as mark-to-market derivatives at June 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		$		$	90,000	$ 7.53	110,000	$ 8.64	200,000	$ 8.14
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
									1,080,000	

Subsequent to June 30, 2007, we entered into derivative positions related to the Amvest Acquisition and the anticipated 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		$		$	1,062,500	$ 8.099	2,070,000	$ 8.124	3,132,500	$ 8.115
2008	1,592,500	$ 8.099	1,592,500	$ 8.099	1,610,000	$ 8.099	1,610,000	$ 8.099	6,405,000	$ 8.099
2009	1,012,500	$ 8.124	1,023,750	$ 8.124	1,035,000	$ 8.124	1,035,000	$ 8.124	4,106,250	$ 8.124
2010	1,575,000	$ 8.099	1,592,500	$ 8.099	1,610,000	$ 8.099	1,610,000	$ 8.099	6,387,500	$ 8.099
									20,031,250	

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	

Investing Activities Acquisitions and Capital Expenditures

Cash used in investing activities was $125.6 million for the six months ended June 30, 2007, compared to $19.7 million for the six months ended June 30, 2006. Our capital expenditures were $11.0 million for the six months ended June 30, 2007, which primarily related to drilling and development of oil and natural gas properties during the quarter. We drilled and completed 20 gross wells (20 net wells) during this six month period in the Robinson s Bend Field. For the six months ended June 30, 2007, we purchased the EnergyQuest Assets for approximately $114.9 million, which is net of cash acquired. During the six months ended June 30, 2006, we paid Everlast $2.4 million, which was the remaining balance of the purchase price for the Robinson s Bend Assets, and expended $7.3 million on the drilling and development of natural gas properties. In addition, we had $12.2 million of cash flows used in investing activities due to the establishment of a cash pool arrangement with CCG.

We currently anticipate our capital budget will be between $25.0 and $27.0 million for the twelve months ending December 31, 2007, excluding the impact of additional acquisitions. The capital budget, which primarily consists of capital for drilling, also includes amounts for infrastructure projects and equipment. The amount and timing of our capital expenditures is largely discretionary and within our control. If natural gas prices decline to levels below acceptable levels, we could choose to defer a portion of these planned capital expenditures until later periods. We routinely monitor and adjust our capital expenditures in response to changes in natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and crews. Based upon current natural gas price expectations for the twelve months ending December 31, 2007, we anticipate that our cash flow from operations and available borrowing capacity under our reserve-based credit facility will exceed our planned capital expenditures and other cash requirements for the twelve months ending December 31, 2007. However, future cash flows are subject to a number of variables, including the level of natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Financing Activities

Our net cash provided by financing activities was $110.0 million for the six months ended June 30, 2007, compared to $11,000 used in financing activities for the six months ended June 30, 2006. We borrowed $60.5 million from our reserve-based credit facility in order to acquire the EnergyQuest Assets, along with issuing $58.8 million of units. We paid dividends of $2.4 million and $6.6 million to our unitholders during February 2007 and May 2007, respectively.

Table of Contents

Contractual Obligations

At June 30, 2007, we had the following contractual obligations or commercial commitments:

	Payments Due By Year[1][2]						
	2007	2008	2009	2010	2011	Thereafter	Total
				(In 000 s)			
Management Services Agreement	$ 721	$	$	$	$	$	$ 721
Reserve-Based Credit Facility				82,500			82,500
Support Services Agreement	120	140					260
Purchase Obligation	185						185
Total	$ 1,026	$ 140	$	$ 82,500	$	$	$ 83,666

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

(2) This table does not include interest as interest rates are variable.

Off-Balance Sheet Arrangements

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

Outlook

During the remainder of 2007, we expect that our business will continue to be affected by the factors described in Part II, Item 1A. Risk Factors, as well as the following key industry and economic trends. Our expectation is based upon key assumptions and information currently available to us. To the extent that our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results. This updated Outlook section includes the impact of the acquisition of the EnergyQuest Assets and the Amvest Acquisition. The acquisition of the Newfield Assets is not expected to close until late September 2007, and is not included in these Outlook amounts.

Production, Drilling, and Capital Expenditures

In 2007, we expect our net production to be between 9.3 Bcf and 10.3 Bcf. This is based on our estimates of the production decline rate on our existing wells and our 2007 drilling program, which we expect to include 90 to 100 newly drilled wells in the Robinson s Bend Field and in the Cherokee Basin. Excluding the impact of additional acquisitions, we expect to spend between $25.0 million and $27.0 million in capital expenditures in 2007. We plan to spend the $0.7 million that has been accrued for environmental liabilities during the remainder of 2007.

Natural Gas Prices and Hedging Activities

Natural gas prices have been volatile over the past three years and even more so in the past twelve to eighteen months. We believe that this trend has been affected by the hurricanes in the late summer and fall of 2005, threats and existence of wars and terrorism in the Middle East and elsewhere, OPEC s management of oil reserves, levels of natural gas held in storage and growth in domestic natural gas demand. The currently high levels of natural gas in storage, resulting at least in part from relatively mild winters in 2005 and 2006 in the United States, have caused natural gas prices to decline from the higher levels prevailing during the later part of 2005 when gas prices increased substantially, particularly in October and November, due to natural gas shortages caused by hurricanes Katrina and Rita.

As of July 1, 2007, we had hedges for 3,329,998 MMBtu of our remaining projected 2007 production from the Robinson Bend Assets and the EnergyQuest Assets at a weighted average sales price of $8.72 per MMBtu. During the remainder of the year, we will evaluate adding hedge volumes for 2007, adding to our hedge levels for 2008, 2009 and 2010, and adding duration to our hedge portfolio beyond 2010. For accounting purposes, these hedges are being treated as cash flow hedges.

As of July 1, 2007, we also had outstanding mark-to-market puts related to production from the EnergyQuest Assets. For accounting purposes, these puts are being treated as mark-to-market derivatives at fair value in our financial statements. In July 2007, we entered into derivative transactions for the projected production related to the Amvest Acquisition, and in August 2007, we entered into derivative transactions in connection with the anticipated acquisition of the Newfield Assets. These derivative positions will be accounted for as mark-to-market activities until they are designated as cash flow hedges.

As described above, we have also hedged our exposure to changes in LIBOR on the interest payments associated with $61.5 million of our outstanding debt. For accounting purposes, this interest rate swap is being treated as a cash flow hedge.

Operating Expenses: Lease Operating Expenses, Production Taxes and General and Administrative Expenses

Our operating expenses include such items as lease operating expenses (labor, vehicle expenses, supervision, transportation, minor maintenance, ad valorem taxes, tools and supplies), production taxes and general and administrative expenses. Due to the current environment of relatively high commodity prices, we anticipate that during 2007, service and labor costs, as well as costs of equipment and raw materials, will remain at or exceed the levels we experienced in 2006. We currently expect our operating expenses for 2007 to be between $26.0 million and $29.0 million. Our production taxes are directly correlated to our revenues, as they are a fixed percentage of sales revenue before the impact of our hedging program. These estimated costs assume that we do not make any further acquisitions in 2007, and that we do not reimburse CEPM under the management services agreement for any acquisition services.

Table of Contents

Higher natural gas and oil prices have led to higher demand for drilling rigs, operating personnel and field supplies and services and have caused increases in the costs of these goods and services. To date, our realized sales prices for natural gas have more than offset the higher drilling and operating costs we have incurred since 2005. Given the inherent volatility of natural gas prices, which are influenced by many factors beyond our control, we plan our activities and budgets based on sales price assumptions that reflect our forward price curve. We focus our efforts on increasing natural gas reserves and maintaining natural gas production levels while controlling costs at a level that is appropriate for long-term operations. Our future cash flow from operations is dependent on our ability to manage our overall cost structure.

Critical Accounting Policies and Estimates

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

As of June 30, 2007, there have been no changes with regard to the critical accounting policies disclosed in our Annual Report on Form 10-K for the year ended December 31, 2006. The policies disclosed included the accounting for natural gas properties, natural gas reserve quantities, net profits interest, revenue recognition and hedging activities. Please read Note 1 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

New Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures for fair value measurements. SFAS No. 157 is effective for all fair value measurements beginning January 1, 2008. We are currently assessing the potential impact of SFAS No. 157.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, including an amendment to FASB No. 115. Under SFAS No. 159, entities may elect to measure specified financial instruments and warranty and insurance contracts at fair value on a contract-by-contract basis, with changes in fair value recognized in earnings each reporting period. The election, called the fair value option, will enable entities to achieve an offset accounting effect for changes in fair value of certain related assets and liabilities without having to apply complex hedge accounting provisions. SFAS No. 159 is expected to expand the use of fair value measurement consistent with the FASB s long-term objectives for financial instruments. SFAS No. 159 is effective as of the beginning of a company s first fiscal year that begins after November 15, 2007. We are currently evaluating the impact that adoption of SFAS No. 159 will have on our future consolidated financial statements.

In April 2007, the FASB issued Staff Position (FSP) FIN 39-1, *Amendment of FASB Interpretation No. 39.* FSP FIN 39-1 permits an entity to report all derivatives recorded at fair value with any associated fair value cash collateral, which are the same counterparty under a master netting arrangement, together in the balance sheet. Under the provisions of this FSP, we must either report all derivatives recorded at fair value net with the associated fair value cash collateral or report all derivative amounts gross. The effects of FSP FIN 39-1 must be applied by adjusting all financial statements presented beginning January 1, 2008. We are currently evaluating the impact of this FSP on our financial statements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas production. Realized pricing is primarily driven by the SONAT Inside FERC Price with respect to our properties in the Robinson s Bend Field and the ONEOK and PEPL Inside FERC Prices with respect to our properties in the Cherokee Basin in Oklahoma and Kansas and the spot market prices applicable to our natural gas production. Pricing for natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside our control.

We have entered into hedging arrangements with respect to a portion of our projected natural gas production through various transactions that hedge the future prices received. These arrangements are natural gas price swaps and put options whereby we receive a fixed price for our production and pay a variable market price to the contract counterparty. These hedging activities are intended to support natural gas prices at targeted levels and to manage our exposure to natural gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes. The table below presents the hypothetical changes in fair values arising from potential changes in the quoted market prices of the commodity underlying the derivative instruments used to mitigate these market risks. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the sale of the hedged natural gas production, which are not included in the table. These derivatives do not hedge all of our commodity price risk related to our forecasted sales of natural gas production and as a result, we are subject to commodity price risks on our remaining unhedged natural gas production.

Fair Value Derivatives

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	(Decrease)	Fair Value	Increase
			(in 000 s)		
Impact of changes in commodity prices on derivative commodity instruments					
June 30, 2007	$ 4,057	$ (8,343)	$ (12,400)	$ 16,457	$ 12,400

Table of Contents

Interest Rate Risk

At June 30, 2007, we had debt outstanding of $82.5 million, which incurred interest at a rate of LIBOR plus an applicable margin between 1.25% and 2.00% based on utilization. At June 30, 2007, the three-month LIBOR interest rate was 5.36%. We enter into hedging arrangements to reduce the impact of volatility of changes in the LIBOR interest rate on our interest payments for our debt. Currently, we have outstanding interest rate swaps that fix the LIBOR rate at 4.74% and 4.964% on $16.5 million and $45.0 million, respectively, of our outstanding debt through February 20, 2010 and September 20, 2010, respectively. At June 30, 2007, the carrying value and fair value of our debt is $82.5 million.

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

		10 Percent Increase		10 Percent Decrease	
	Fair Value	**Fair Value**	**Increase**	**Fair Value**	**(Decrease)**
			(in 000 s)		
Impact of changes in LIBOR on derivative interest rate instruments					
June 30, 2007	$ 673	$ 863	$ 190	$ 483	$ (190)

Item 4. Controls and Procedures

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, with CEP have been detected. These inherent limitations include error by personnel in executing controls due to faulty judgment or simple mistakes, which could occur in situations such as when personnel performing controls are new to a job function or when inadequate resources are applied to a process. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no absolute assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions or personnel, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Evaluation of Disclosure Controls and Procedures. The Chief Executive Officer and the Chief Financial Officer of CEP have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of the fiscal quarter covered by this quarterly report (the Evaluation Date). Based on such evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that, as of the Evaluation Date, CEP s disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. During the quarter ended June 30, 2007, there was no change in CEP s internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that has materially affected, or is reasonably likely to materially affect, CEP s internal control over financial reporting.

Table of Contents

PART II OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in Item 1A. to Part I of our Annual Report on Form 10-K for the year ended December 31, 2006 (2006 Form 10-K), except as noted below. An investment in our common units involves various risks. When considering an investment in us, careful consideration should be given to the risk factors described in our 2006 Form 10-K, as well as the risk factors noted below. These risks and uncertainties are not the only ones facing us and there may be additional matters that are not known to us or that we currently consider immaterial. All of these risks and uncertainties could adversely affect our business, financial condition or future results and, thus, the value of an investment in us.

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 August 2007, we announced that we entered into a definitive purchase agreement to acquire the Newfield Assets for approximately $128.0 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 goodwill or other intangible assets, asset devaluation or restructuring charges; unforeseen difficulties encountered in operating in new geographic areas; 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.

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.

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, however, 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 June 30, 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.

Table of Contents

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. 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. The Trust further announced that it is in the process of preparing the notice of special meeting and information statement and will provide such notice as promptly as practicable to the Trust unitholders. 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.

Certain of our undeveloped leasehold acreage are 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 these leases expire in the Robinson s Bend Field or in the Cherokee Basin, we will lose our right to develop the related properties.

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.

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.

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 32% of the outstanding limited liability company interests of CEP as of July 31, 2007. The percentages do not reflect any common units that may be issued under our long-term incentive plan or in connection with the acquisition of the Newfield Assets. CEPM, as the holder of all our Class A units, will have the exclusive right to elect two members of our board of managers.

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 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.

Table of Contents

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.

Forward-Looking Statements

This Quarterly Report on Form 10-Q 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 termination of the Robinson s Bend 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 Quarterly Report on Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and other items within this Quarterly Report on Form 10-Q. 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, the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q 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 Quarterly Report on Form 10-Q 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 Quarterly Report on Form 10-Q. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None, not previously reported.

Item 3. Defaults Upon Senior Securities

None.

Table of Contents

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

We held a special annual meeting of our common unitholders on June 26, 2007 at which our common unitholders approved a proposal to approve a change in the terms of our Class E units to permit the conversion of all outstanding Class E units into the same number of our common units and the issuance of additional common units in such amount upon such conversion (the Class E Conversion and Issuance Proposal), as follows:

	Votes For	Votes Against	Abstained
Class E Conversion and Issuance Proposal	8,591,855	28,079	10,554

Item 5. Other Information

None.

Item 6. Exhibits

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

1. Financial Statements:

Consolidated Statements of Operations and Comprehensive Income (Loss) Constellation Energy Partners LLC for the three and six months ended June 30, 2007 and June 30, 2006

Consolidated Balance Sheets Constellation Energy Partners LLC at June 30, 2007 and December 31, 2006

Consolidated Statements of Cash Flows Constellation Energy Partners LLC for the six months ended June 30, 2007 and June 30, 2006

Consolidated Statements of Changes in Members Equity and Comprehensive Income Constellation Energy Partners LLC for the six months ended June 30, 2007

Notes to Consolidated Financial Statements

Exhibit Number	Description
2.1	Agreement of Merger, dated as of July 12, 2007, by and among CEP Cherokee Basin LLC, AMVEST Osage, Inc. and AMVEST Oil & Gas, Inc. (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
3.1	Certificate of Formation of Constellation Energy Partners LLC, as amended (incorporated herein by reference to Exhibit 3.1 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 12, 2007).
3.2	Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006).
3.3	Amendment No. 1 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007).
3.4	

	Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
4.1	Registration Rights Agreement, dated as of July 25, 2007, by and among Constellation Energy Partners LLC and the Purchasers named therein (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
10.1	Class F Unit and common Unit Purchase Agreement, dated as of July 12, 2007, by and among Constellation Energy Partners LLC and the Purchasers named therein (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
*31.1	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer, Chief Accounting Officer and Treasurer of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chairman Financial Officer, Chief Accounting Officer and Treasurer of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant, Constellation Energy Partners LLC, has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

		CONSTELLATION ENERGY PARTNERS LLC
		(REGISTRANT)
Date: August 9, 2007	By	/s/ Angela A. Minas Chief Financial Officer, Chief Accounting Officer And Treasurer

EXHIBIT INDEX

Exhibit Number	Description
2.1	Agreement of Merger, dated as of July 12, 2007, by and among CEP Cherokee Basin LLC, AMVEST Osage, Inc. and AMVEST Oil & Gas, Inc. (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
3.1	Certificate of Formation of Constellation Energy Partners LLC, as amended (incorporated herein by reference to Exhibit 3.1 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 12, 2007).
3.2	Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006).
3.3	Amendment No. 1 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007).
3.4	Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
4.1	Registration Rights Agreement, dated as of July 25, 2007, by and among Constellation Energy Partners LLC and the Purchasers named therein (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
10.1	Class F Unit and common Unit Purchase Agreement, dated as of July 12, 2007, by and among Constellation Energy Partners LLC and the Purchasers named therein (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
*31.1	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer, Chief Accounting Officer and Treasurer of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chairman Financial Officer, Chief Accounting Officer and Treasurer of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith