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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended September 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 **(State of organization)**	**11-3742489** **(I.R.S. Employer Identification No.)**
111 Market Place **Baltimore, Maryland** **(Address of Principal Executive Offices)**	**21202** **(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 ☒ 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 ☒

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

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 October 31, 2007: 21,904,106 units

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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 September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In 000's except unit data)			
Revenues				
Oil and gas sales	$ 23,536	$ 8,549	$ 50,033	$ 26,154
Gain/(Loss) from mark-to-market activities (see Note 5)	2,635	—	(2,766)	—
Total revenues	26,171	8,549	47,267	26,154
Expenses:				
Operating expenses:				
Lease operating expenses	5,077	1,826	9,822	5,321
Cost of sales	656	—	656	—
Production taxes	992	431	2,136	1,340
General and administrative	2,667	714	6,057	3,445
Loss (gain) on sale of asset	(8)	—	86	—
Depreciation, depletion, and amortization	7,619	2,176	13,162	5,987
Accretion expense	98	35	211	106
Total operating expenses	17,101	5,182	32,130	16,199
Other expense (income)				
Interest expense	2,384	1	4,209	2
Interest income	(168)	(165)	(303)	(363)
Other income	(29)	—	(99)	—
Total other expenses (income)	2,187	(164)	3,807	(361)
Total expenses	19,288	5,018	35,937	15,838
Net income	$ 6,883	$ 3,531	$ 11,330	$ 10,316
Other comprehensive income (loss)	3,233	13,136	(372)	14,050
Comprehensive income	$ 10,116	$ 16,667	$ 10,958	$ 24,366
Earnings per unit				
Earnings per unit—Basic	$ 0.37	$ 0.31	$ 0.79	$ 0.91
Units outstanding—Basic	18,398,146	11,320,300	14,289,600	11,320,300
Earnings per unit—Diluted	$ 0.37	$ 0.31	$ 0.79	$ 0.91
Units outstanding—Diluted	18,400,709	11,320,300	14,292,163	11,320,300
Distributions declared and paid per unit	$ 0.4625	$ —	$ 1.1361	$ —

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

	September 30, 2007 (Unaudited)	December 31, 2006
	(In 000's)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 19,519	$ 7,485
Accounts receivable	17,351	9,609
Prepaid expenses	353	317
Risk management assets	8,631	8,654
Other	839	22
Total current assets	46,693	26,087
Natural gas properties (see Note 7)		
Natural gas properties, equipment and facilities	671,160	181,995
Material and supplies	2,666	1,264
Less accumulated depreciation, depletion and amortization	(24,700)	(11,620)
Net natural gas properties	649,126	171,639
Other assets		
Debt issue costs (net of accumulated amortization of $339 at September 30, 2007 and $48 at December 31, 2006)	1,462	1,138
Risk management assets	5,076	4,761
Other non-current assets	13,957	72
Total assets	$ 716,314	$ 203,697
LIABILITIES AND MEMBERS' EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 3,814	$ 66
Payable to affiliate	4,213	2,836
Accrued liabilities	10,151	3,017
Environmental liabilities	687	721
Risk management liabilities	742	—
Royalty payable	3,931	2,367
Total current liabilities	23,538	9,007
Other liabilities		
Asset retirement obligation	9,651	2,730
Risk management liabilities	1,048	—
Debt	147,000	22,000
Total other liabilities	157,699	24,730
Total liabilities	181,237	33,737
Commitments and contingencies (see Note 9)		
Class D Interests	7,333	8,000
Members' equity		
Class A units, 447,022 and 226,406 shares authorized, issued and outstanding, respectively	10,300	2,977
Class B units, 22,795,785 and 11,093,894 shares authorized, respectively, and 22,351,128 and 11,093,894 shares issued and outstanding, respectively	504,703	145,870
Accumulated other comprehensive income	12,741	13,113
Total members' equity	527,744	161,960
Total liabilities and members' equity	$ 716,314	$ 203,697

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In 000's)	
Cash flows from operating activities:		
Net income	$ 11,330	$ 10,316
Adjustments to reconcile net income to cash (used in) provided by operating activities:		
Expenses paid by CCG on behalf of CEP	—	370
Depreciation, depletion and amortization	13,162	5,987
Amortization of debt issuance costs	291	—
Accretion of plugging and abandonment liability	211	106
Equity earnings in affiliate	(99)	—
Loss from disposition of property and equipment	86	—
Hedge ineffectiveness	1,463	—
Loss from mark-to-market activities	2,766	(129)
Long-term incentive plan	22	—
Changes in Assets and Liabilities:		
Change in net derivative activities	(3,103)	—
(Increase) decrease in accounts receivable	(4,391)	1,146
Decrease (increase) in prepaid expenses	114	(13)
Increase in other assets	(818)	(2,137)
Increase (decrease) in accounts payable	2,717	(3,811)
(Decrease) increase in payable to affiliate	1,377	3,616
Increase (decrease) in accrued liabilities	7,848	10
Increase (decrease) in royalty payable	284	(1,148)
Net cash provided by operating activities	33,260	14,313
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash acquired	(482,458)	(261)
Development of natural gas properties	(17,679)	(10,071)
Proceeds from sale of equipment	188	—
Distributions from equity affiliate	200	—
Investment in affiliate cash pool	—	(12,362)
Net cash used in investing activities	(499,749)	(22,694)
Cash flows from financing activities:		
Members' distributions	(15,698)	—
Proceeds from issuance of debt	131,000	—
Repayment of debt	(6,000)	(63)
Proceeds from issuance of units	369,835	—
Debt issue costs	(614)	—
Net cash provided by (used in) financing activities	478,523	(63)
Net increase (decrease) in cash	12,034	(8,444)
Cash and cash equivalents, beginning of period	7,485	14,831
Cash and cash equivalents, end of period	$ 19,519	$ 6,387
Supplemental disclosures of cash flow information:		
Non-cash items		
Expenses paid by CCG on behalf of CEP	$ —	$ 370
Accrued capital expenditures	1,474	319
Cash received during the period for interest	253	—
Cash paid during the period for interest	$ (2,590)	$ (2)

See accompanying notes to consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Changes in Members' Equity

(Unaudited)

	Class A		Class B		Accumulated Other Comprehensive Income	Total Members' Equity
	Units	Amount	Units	Amount		
	(In 000's, except unit amounts)					
Balance, January 1, 2007	226,406	$ 2,977	11,093,894	$145,870	$ 13,113	$161,960
Distributions	—	(301)	—	(14,730)	—	(15,031)
Change in fair value of commodity hedges	—	—	—	—	11,476	11,476
Cash settlement of commodity hedges	—	—	—	—	(11,055)	(11,055)
Change in fair value of interest rate hedges	—	—	—	—	(793)	(793)
Sale of units, net of offering expense of $5,179	220,616	7,396	10,810,212	362,439	—	369,835
Long-term incentive program	—	1	—	21	—	22
Net income	—	227	—	11,103	—	11,330
Balance, September 30, 2007	447,022	$10,300	21,904,106	$504,703	$ 12,741	$527,744

See accompanying notes to consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

The consolidated financial statements at September 30, 2007 and for the three and nine months ended September 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 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.

Accumulated Other Comprehensive Income

The Company's accumulated other comprehensive income represents net unrealized gains or losses related to the Company's derivative hedge positions for which the Company uses hedge 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 and as Risk management assets and liabilities in its Consolidated Balance Sheets.

Unit-Based Compensation

The Company records compensation expense for all equity grants issued under the Long-Term Incentive Program based on the fair value at the grant date, recognized over the vesting period, according to Statement of Financial Accounting Standards (“SFAS”) No. 123 (R), *Stock-Based Payment”*.

3. 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. 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.

4. ACQUISITIONS

Newfield Acquisition

The Newfield acquisition was completed on September 21, 2007 (“Closing Date”). The Company acquired certain oil and natural gas properties in the Cherokee Basin from Newfield Exploration Mid-Continent Inc. (“Newfield”) for approximately $128.0 million, subject to purchase price adjustments. The Company also completed a private placement of 2,470,592 common units at an average price of $42.50 per unit for an aggregate purchase price of approximately $105 million. The Company also filed a registration statement with the SEC on November 1, 2007, registering for resale the common units, which is not yet effective. The proceeds from this equity placement, together with borrowings under the Company’s existing credit facility, fully funded the purchase price of the acquisition. The 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 acquisition included approximately 600 net producing wells on approximately 80,000 net acres. Also included were support equipment and facilities, including a pipeline gathering system.

The total consideration was $132.7 million which consisted of cash of $129.0 million and estimated transaction costs of $1.0 million. The Company assumed liabilities of $2.7 million, primarily associated with abandonment obligations on the properties. The purchase price allocation of the total consideration of $132.7 million is as follows:

Natural Gas and Oil Properties	$ 113.5 million
Unproved Properties	2.6 million
Pipelines	10.0 million
Other PP&E	1.0 million
Intangible Third Party Gas Contracts	5.0 million
Inventory	0.6 million
Total	$ 132.7 million

The preliminary purchase price allocation used for the purpose of this pro forma financial information 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 Newfield acquisition is preliminary and subject to change, pending finalization of the valuation of the assets and liabilities acquired.

A post-closing adjustment will occur within 90 days of the Closing Date to settle certain items including the revenue distributions and certain expenses associated with the oil and gas properties after the effective date of July 1, 2007. Additionally, as of the Closing Date, Newfield had been unable to obtain third-party consents (the “Outstanding Consents”) with respect to certain oil and gas leases and related assets (the “Designated Properties”) which represent less than 14% of the aggregate purchase price of the acquisition. As a result of the Outstanding Consents, Newfield and the Company entered into a Nominee Agreement pursuant to which Newfield will hold legal title for the benefit of the Company for the Designated Properties. As required under the Nominee Agreement, during the 90 day period following the Closing Date (the “Cure Period”), Newfield shall use diligent, commercially reasonable efforts to obtain the Outstanding Consents with respect to the Designated Properties, and shall deliver to the Company assignments of all of its right, title and interest in all of the Designated Properties as to which Outstanding Consents are obtained during the Cure Period. If Newfield fails to obtain Outstanding Consents for any of the Designated Properties within the Cure Period, the Company may reassign to Newfield its beneficial interest in such property and shall be entitled to a refund from Newfield of the purchase price paid with respect to such property, subject to certain adjustments.

Amvest Acquisition

The Amvest acquisition was completed on July 25, 2007. The Company acquired certain oil and natural gas properties in the Cherokee Basin through an agreement of merger providing for the merger of Amvest Osage, Inc. (“Amvest”) with and into a wholly-owned subsidiary of the Company for approximately $240.0 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. At a special meeting of the Company’s common unitholders held on October 12, 2007, the common unitholders approved the conversion of all outstanding Class F units into common units. As a result of the approval, all 3,371,219 of the Company’s outstanding Class F units were cancelled and the same number of common units was issued to the former holders of Class F units. The Company also filed a registration statement with the SEC on November 1, 2007, registering for resale the common units and common units issued upon conversion of the Class F units, which is not yet effective. The proceeds from this equity placement, together with borrowings under the Company’s existing credit facility, fully funded the purchase price of the acquisition. The 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 acquisition included a 13 year exclusive concession for coalbed methane and shale rights on approximately 560,000 net acres in Osage County, Oklahoma and approximately 370 producing wells. Also included were support equipment and facilities, including certain pipeline gathering systems.

The total consideration was $244.8 million which consisted of cash of $243.3 million and estimated transaction costs of $1.5 million. An amount of $8.5 million was included in a drilling escrow fund that was returned to the Company for use for drilling programs on proved undeveloped locations after the close of the transaction. The purchase price allocation of the total consideration (after the return of the drilling fund) of $236.3 million is as follows:

Natural Gas and Oil Properties	$ 184.2 million
Unproved Properties	38.4 million
Pipelines	5.0 million
Other PP&E	1.4 million
Intangible Third Party Gas Contracts	5.0 million
Net Working Capital	2.3 million
Total	$ 236.3 million

The preliminary purchase price allocation used for the purpose of this pro forma financial information is based on preliminary appraisals, evaluations of proved oil and natural gas reserves, discounted cash flows, quoted market prices, other estimates by management, and a preliminary valuation report. The purchase price allocation related to the Amvest acquisition is preliminary and subject to change, pending finalization of the valuation of the assets and liabilities acquired.

EnergyQuest Acquisition

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 now effective. The proceeds from this equity placement, together with borrowings under the Company's existing credit facility, fully funded the purchase price of the acquisition. The 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
	$118.0 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 nine months ended September 30, 2007 and 2006 have been prepared to give effect to the EnergyQuest, Amvest, and Newfield acquisitions described above on our results of operations as if they had been consummated at the beginning of the period presented. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if these acquisitions had been completed on such date or to project our results of operations for any future date or period.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(Unaudited) (In 000's, except per share data)			
Pro forma:				
Revenue	$34,308	$29,312	$92,727	$86,428
Income from operations	$10,559	$ 5,938	$23,354	$20,789
Net income	$ 7,777	$ 3,683	$15,325	$13,894
Basic earnings per share	$ 0.35	$ 0.16	$ 0.69	$ 0.62
Diluted earnings per share	$ 0.35	$ 0.16	$ 0.69	$ 0.62

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 $12.7 million and $13.1 million at September 30, 2007 and December 31, 2006, respectively. The Company expects that $6.6 million will be reclassified from Accumulated other comprehensive income to the income statement in the next twelve months. There was approximately $1.5 million of expense as a result of hedge ineffectiveness for the nine months ended September 30, 2007.

At September 30, 2007 and December 31, 2006, the Company had debt outstanding of $147.0 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 $91.0 million of the outstanding debt through October 2010. The interest rate swaps have termination dates of February 20, 2010, September 20, 2010, and October 19, 2010. The swaps have been designated as cash flow hedges of the risk associated with changes in the designated benchmark 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, *Accounting for Derivative Instruments and Hedging Activities*. 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 loss of approximately $0.7 million at September 30, 2007 and a gain of $0.1 million at December 31, 2006, respectively.

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. In July 2007, the Company entered into a series of swaps in connection with the Amvest acquisition. These swaps were accounted for as mark-to-market activities until August 2007, when the swaps were designated as cash flow hedges. In August 2007, the Company entered into a combination of swaps and swaptions in connection with the acquisition of the Newfield assets. These derivative positions are accounted for as mark-to-market activities. For the nine months ended September 30, 2007, the Company recognized a net unrealized loss of approximately $2.7 million in connection with these positions. At September 30, 2007, the fair value of the puts, swaptions, and Newfield swaps was a net asset of approximately $3.4 million.

Credit Support Fee Agreements

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

- In March 2007, in connection with the EnergyQuest acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $25 million for certain financial derivatives that we entered into with The Royal Bank of Scotland plc ("RBS"). This guarantee has been released.
- In March 2007, in connection with the EnergyQuest acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $11.5 million for certain financial derivatives that we entered into with BNP Paribas ("BNP"). This guarantee has been released.
- In July 2007, in connection with the Amvest acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $15.0 million for certain financial derivatives that we entered into with BNP. This guarantee has been released.
- In August 2007, in connection with the Newfield acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $10.0 million for certain financial derivatives that we entered into with BNP.

As of September 30, 2007, we have paid Constellation $0.2 million for the credit support.

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 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 $180.0 million on July 26, 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 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 September 30, 2007 were approximately $1.8 million and will be amortized over the life of the facility.

As of September 30, 2007 and December 31, 2006, the Company had $147.0 million and $22.0 million, respectively, in outstanding debt under its reserve-based credit facility. As of September 30, 2007, the Company had $33 million in borrowing capacity under the reserve-based credit facility.

7. NATURAL GAS PROPERTIES

Natural gas properties consist of the following:

	September 30, 2007	December 31, 2006
	(In 000's)	
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 627,573	$ 181,747
Unproved property	42,685	88
Total property costs	670,258	181,835
Materials and supplies	2,666	1,264
Land	902	160
Total	673,826	183,259
Less: Accumulated depreciation, depletion and amortization	(24,700)	(11,620)
Oil and natural gas properties and equipment, net	$ 649,126	$ 171,639

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 $1.4 million for the nine months ended September 30, 2006. CEP had a related party payable to CCG of $4.2 million and $2.8 million as of September 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 charge CEP for acquisition services or other services under the management services agreement, provided that CEPM may receive added compensation for providing CEP with services as a result of the management incentive interests it holds in CEP. 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 nine months ended September 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 nine months ended September 30, 2007, $4.2 million in costs were accrued under this agreement, which will be paid on November 14, 2007.

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.

Beginning in September 2007, CCG began purchasing natural gas from CEP in the Cherokee Basin. The marketing arrangement, administered by Newfield under a transition services agreement for October 2007 and November 2007 production, was reviewed by the Conflicts Committee of CEP's Board of Managers. The committee found that the arrangement was fair to and in the best interests of CEP.

During the nine months ended September 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 September 30, 2007 and December 31, 2006, other than the matters discussed below, there were no matters which, in the opinion of management, would have a material adverse effect on the financial position, results of operations or cash flows of CEP.

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 $0.3 million was paid to the holder of the Company's Class D interests on August 14, 2007. A distribution of $0.3 million will also be paid to the holder of the Company's Class D interests on November 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, 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.

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 process of preparing the notice of such special meeting which will include the time and place thereof.

For CEP's 2007 drilling program, CEP has committed to purchase approximately $1.0 million in pipe from a vendor. As of September 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.

The following table is a reconciliation of the ARO:

	September 30, 2007		December 31, 2006
		(In 000's)	
Asset retirement obligation, beginning balance	$ 2,730		$ 2,524
Obligation assumed in acquisition (Note 4)	6,652		—
Additions	58		65
Accretion expense	211		141
Asset retirement obligation, ending balance	$ 9,651		$ 2,730

At September 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 nine months ended September 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 nine months ended September 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 September 30, 2007 and December 31, 2006, accrued environmental obligations were $0.7 million, which were classified as current on CEP's Consolidated 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 $0.3 million was paid to the holder of the Company's Class D interests on May 15, 2007.

On August 14, 2007, the Company paid a distribution for the second quarter of 2007 to the unitholders of record at August 7, 2007. The distribution was paid to holders of common units and Class A units at a rate of $0.4625 per unit. The distribution was not paid to holders of Class F units or to the holders of common units issued in connection with the Amvest acquisition. See Note 3 for a discussion of the Amvest acquisition.

A distribution of $0.3 million was paid to the holder of the Company's Class D interests on August 14, 2007.

On October 24, 2007, the Company declared a distribution for the third quarter of 2007 to the unitholders of record at November 7, 2007. The distribution will be paid to holders of common units and Class A units at a rate of $0.5625 per unit on November 14, 2007. The increase in the distribution rate will commence a management incentive interest vesting period under the Company's operating agreement. An initial cash reserve of $0.1 million has been established to fund future distributions on the management incentive interests.

A distribution of $0.3 million will also be paid to the holder of the Company's Class D interests on November 14, 2007.

14. Unit-Based Compensation

The Company granted 5,343 restricted common unit awards on September 14, 2007, to the independent, non-employee members of the Board of Managers. These units had a total fair market value of $225,000 at the grant date. This amount will be recognized over the vesting period. These service-based restricted common units will vest in full on March 1, 2008. The grant of restricted common units forfeits on a pro rata basis if service as a manager terminates prior to the vesting date of March 1, 2008. The Company recognized $22,000 of expense in the three and nine months ended September 30, 2007.

15. 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.

16. SUBSEQUENT EVENTS

Conversion of Class F Units

At a special meeting of the Company's common unitholders held on October 12, 2007, the common unitholders approved the conversion of all outstanding Class F units into common units. As a result of the approval, all 3,371,219 of the Company's outstanding Class F units were cancelled and the same number of common units was issued to the former holders of Class F units.

Interest Rate Swaps

In October 2007, 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 $18.5 million of the outstanding debt through October 2010. The LIBOR interest rate swaps are at 4.58% and 4.56% have termination dates of August 20, 2010, and October 22, 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.

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 September 30, 2007, our estimated proved reserves consisted of oil and natural gas and were located in the Black Warrior Basin of Alabama 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" or "EnergyQuest Acquisition"). In July 2007, we completed an acquisition of additional oil and natural gas properties located in the Cherokee Basin in Oklahoma (the "Amvest Acquisition"). In September 2007, we completed the acquisition of additional coalbed methane properties in the Cherokee Basin of Oklahoma (the "Newfield Assets" or "Newfield Acquisition"). These acquisitions are discussed in more detail in Note 4 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," "CEP," 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;
- realized loss (gain) on cancelled natural gas derivatives.; and
- other similar charges.

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.

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 September 30, 2007	For the Three Months Ended September 30, 2006	For the Nine Months Ended September 30, 2007	For the Nine Months Ended September 30, 2006
	(In 000's)			
Reconciliation of Net Income to Adjusted EBITDA:				
Net income	$ 6,883	$ 3,531	$ 11,330	$ 10,316
Adjusted by:				
Interest expense (income), net	2,216	(164)	3,906	(361)
Depreciation, depletion and amortization	7,619	2,176	13,162	5,987
Accretion of asset retirement obligation	98	35	211	106
Loss (gain) on sale of asset	(8)	—	86	—
Loss (gain) on mark-to-market activities	(2,635)	—	2,766	—
Long-term incentive plan	22	—	22	—
Unrealized loss (gain) on natural gas derivatives	1,637	(129)	1,463	(129)
Adjusted EBITDA	$ 15,832	$ 5,449	$ 32,946	$ 15,919

Significant Operational Factors since December 31, 2006

- *Realized Prices.* Our average realized price for the nine months ended September 30, 2007, including hedges, was $7.65 per Mcfe. This realized price includes the impact of $2.8 million of losses on mark-to-market derivatives that were entered into in anticipation of closing our acquisitions of additional coalbed methane properties in the Cherokee Basin. Excluding the impact of the mark-to-market losses, the average realized price for the nine months ended September 30, 2007 was $8.09 per Mcfe.
- *Production.* Our production during the first nine months of 2007 was 6.2 Bcfe, or an average of 22,641 Mcfe per day. Our September 2007 production was approximately 41,967 Mcfe per day, which includes production from the Newfield assets beginning on September 21, 2007.
- *Capital Expenditures and Drilling Results.* For the nine months ended September 30, 2007, we incurred approximately $16.5 million in capital expenditures. We accelerated our drilling program in the Black Warrior Basin and have drilled and completed 20 wells with a 100% drilling success rate. We have also drilled 34 net wells and performed 20.5 net recompletions in the Cherokee Basin as of September 30, 2007.
- *Operating Expenses.* Operating expenses increased from 2006, reflecting the addition of the Cherokee Basin assets, as well as acquisition and integration related costs of approximately $0.3 million, and the transition services agreements with EnergyQuest, Amvest, and Newfield.

  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. We are currently in discussions with Constellation to renew the agreement for 2008. 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 three complementary coalbed methane acquisitions.

  Newfield Acquisition

  In September 2007, we completed the Newfield Acquisition for approximately $128 million, subject to purchase price adjustments. We also completed a private placement of 2,470,592 common units at a price of $42.50 per unit for an aggregate purchase price of approximately $105 million. We filed a registration statement with the SEC on November 1, 2007, registering for resale the common units, which is not yet effective. The proceeds from the equity private placement, together with funds available under our existing credit facility, fully funded the purchase price of the acquisition. We entered into derivative transactions to hedge the future expected production associated with this acquisition and borrowed $28.0 million under our reserve-based credit facility to fund the 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 converted into common units, on a one-for-one basis, upon obtaining common unit holder approval on October 12, 2007. We filed a registration statement with the SEC on November 1, 2007, registering for resale the common units and the common units issued upon conversion of the Class F units, which is not yet effective. 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 and borrowed $33.5 million under our reserve-based credit facility, along with $1.0 million of cash on hand, to fund the acquisition.

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, which is now effective. 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.

- *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 was decreased by approximately 400 Mcfe per day for the month of July. The Verdigris River crossing was washed out, which impacted our production through July 16, 2007 by approximately 800 Mcfe 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 incurred 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. We also entered into derivative transactions to hedge certain of the future expected production associated with our EnergyQuest, Amvest, and Newfield acquisitions. The swaps associated with the EnergyQuest and Amvest acquisitions 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. All of our derivatives associated with the Newfield acquisition are being accounted for using mark-to-market accounting. All of our derivative positions are outlined on page 25.
- *Debt.* The initial borrowing base of our reserve-based credit facility was set at $75.0 million, but was increased to $180.0 million on July 26, 2007. The credit facility will mature in October 2010. As of September 30, 2007, we had $147.0 million in outstanding debt under our reserve-based credit facility.

Results of Operations

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

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	For the Three Months Ended				For the Nine Months Ended			
	September 30, 2007	September 30, 2006	Variance $	Variance %	September 30, 2007	September 30, 2006	Variance $	Variance %
	(In 000's, except production, cost and price data)							
Revenues:								
Oil and gas sales	$ 23,536	$ 8,549	$14,987	175.3%	$ 50,033	$ 26,154	$23,879	91.3%
Gain (loss) from mark-to-market activities	2,635	—	2,635	100.0%	(2,766)	—	(2,766)	(100.0)%
Total revenues	26,171	8,549	17,622	206.1%	47,267	26,154	21,113	80.7%
Operating expenses:								
Lease operating expenses	5,077	1,826	3,251	178.0%	9,822	5,321	4,501	84.6%
Cost of sales	656	—	656	100.0%	656	—	656	100.0%
Production taxes	992	431	561	1.3%	2,136	1,340	796	59.4%
General and administrative expenses	2,667	714	1,953	273.5%	6,057	3,445	2,612	75.8%
Loss (gain) on sale of asset	(8)	—	(8)	100.0%	86	—	86	100.0%
Depreciation, depletion and amortization	7,619	2,176	5,443	250.1%	13,162	5,987	7,175	119.8%
Accretion expenses	98	35	63	180.0%	211	106	105	99.1%
Total operating expenses	17,101	5,182	11,919	230.0%	32,130	16,199	15,931	98.4%
Other expenses (income):								
Interest expense	2,384	1	2,383	2,383.0%	4,209	2	4,207	2,103.5%
Interest income	(168)	(165)	(3)	1.8%	(303)	(363)	60	(16.5)%
Other	(29)	—	(29)	100.0%	(99)	—	(99)	100.0%
Total other expenses (income)	2,187	(164)	2,351	(1,433.5)%	3,807	(361)	4,168	(11.55)%
Total expenses	19,288	5,018	14,270	284.4%	35,937	15,838	20,099	126.9%
Net income	$ 6,883	$ 3,531	$ 3,352	94.9%	$ 11,330	$ 10,316	$ 1,014	9.8%
Net production:								
Total production (MMcfe)	3,158	1,191	1,967	165.2%	6,181	3,391	2,790	82.3%
Average daily production (Mcfe/d)	34,326	12,946	21,380	165.2%	26,641	12,422	14,219	114.5%
Average sales prices:								
Price per Mcfe including hedges	$ 8.29(a)	$ 7.18	$ 1.11	15.46%	$ 7.65(a)	$ 7.71	$ (0.06)	(1.0)%
Price per Mcfe excluding hedges	$ 5.84	$ 7.07	$ (1.23)	(17.4)%	$ 6.57	$ 7.67	$ (1.10)	(14.3)%
Average unit costs per Mcfe:								
Field operating expenses(b)	$ 1.92	$ 1.89	$ 0.03	1.5%	$ 1.94	$ 1.96	$ (0.02)	(1.0)%
Lease operating expenses	$ 1.61	$ 1.53	$ 0.08	5.2%	$ 1.59	$ 1.57	$ 0.02	1.3%
Production taxes	$ 0.31	$ 0.36	$ (0.05)	(13.8)%	$ 0.35	$ 0.39	$ (0.04)	(10.2)%
General and administrative expenses	$ 0.84	$ 0.60	$ 0.24	40.0%	$ 0.98	$ 1.02	$ (0.04)	(3.9)%
Depreciation, depletion and amortization	$ 2.41	$ 1.83	$ 0.58	31.7%	$ 2.13	$ 1.77	$ 0.36	20.3%

(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 September 30, 2007 compared to the three months ended September 30, 2006

Oil and gas sales. Oil and natural gas sales increased $14.9 million, or 175.3%, to $23.5 million for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006. Of this increase, $13.9 million was attributable to increased production volumes and $4.8 million was attributable to our hedge program which was implemented subsequent to June 2006, offset by a $3.8 million impact of lower market prices for oil and natural gas. Production for the three months ended September 30, 2007 was 3.1 Bcfe, which was higher than the three months ended September 30, 2006 as a result of our drilling program and operational improvements, along with the acquisition of our properties in the Cherokee Basin. The acquisition of properties in the Cherokee Basin contributed 1.3 Bcfe of the increase. We hedged approximately 89% of our actual production from April 2007 through September 2007. As discussed below, the gain from our mark-to-market activities increased $2.6 million for the three months ended September 30, 2007, as compared to the three months ended September 30, 2006. Our realized prices increased from 2006 to 2007 because the impact of our hedging program and 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 September 30, 2006. However, in conjunction with the EnergyQuest Acquisition, the Amvest Acquisition, and the Newfield Acquisition, we entered into derivative transactions to hedge a portion of the future expected production associated with these acquisitions, before the acquisitions closed. These derivatives were accounted for as mark-to-market derivatives and were recorded at fair value in our financial statements until June 18, 2007 for EnergyQuest and until August 20, 2007 for Amvest, at which time the swaps were designated as cash flow hedges and began receiving cash flow accounting treatment. The Newfield derivative transactions are still accounted for as mark-to-market derivatives. For the quarter ended September 30, 2007, the mark-to-market gain was $2.6 million.

We have entered into cash flow hedges in an effort to reduce our exposure to short-term fluctuations in natural gas prices. For the three months ended September 30, 2007, we recognized a loss of approximately $1.6 million related to hedge ineffectiveness primarily related to our hedges of production in the Cherokee Basin. Hedge settlements were $6.8 million for the three months ended September 30, 2007.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicle, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes. 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 September 30, 2007, field operating expenses increased $3.8 million, or 179.3%, to $6.1 million, compared to expenses of $2.3 million for the three months ended September 30, 2006. This increase was primarily the result of the costs of operating the properties acquired in the EnergyQuest and Amvest acquisitions. In June and July 2007, Oklahoma and Kansas received record amounts of rainfall and had extensive flooding. This resulted in increased operating expenses due to weather and associated maintenance and repairs. Cost of sales was $0.7 million for the three months ended September 30, 2007, which represents the cost of purchased natural gas in the Cherokee Basin.

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.

General and administrative expenses increased $1.9 million, or 273.5%, to $2.7 million for the three months ended September 30, 2007, as compared to the three months ended September 30, 2006. This increase was primarily due to increased costs associated with the transition services agreements with EnergyQuest, Amvest, and Newfield, and expenses related to the management services agreement, under which CEPM bills us for services and costs incurred on our behalf. In the third 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 September 30, 2007 was $7.6 million, or $2.41 per Mcfe, compared to $2.1 million, or $1.83 per Mcfe, for the three months ended September 30, 2006. This increase reflects the increased basis in our assets resulting from additional capital expenditures, asset acquisitions, and increased production volumes between September 30, 2006 and September 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 September 30, 2007 increased $2.4 million as compared to approximately $1,000 in interest expense for the three months ended September 30, 2006. This increase was due to the borrowings under our reserve-based credit facility, which we entered into on October 31, 2006. At September 30, 2007, we had an outstanding balance under the credit facility of $147.0 million.

Interest income. Interest income was $0.2 million for the three months ended September 30, 2007 and $0.2 million for the three months ended September 30, 2006. During the three months ended September 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.

Nine months ended September 30, 2007 compared to the nine months ended September 30, 2006

Oil and gas sales. Oil and natural gas sales increased $23.8 million, or 91.3%, to $50.0 million for the nine months ended September 30, 2007. Of this increase, $21.4 million was attributable to increased production volumes and $9.2 million was attributable to our hedge program, offset by a $6.8 million impact of lower market prices for oil and natural gas. Production for the nine months ended September 30, 2007 was 6.1 Bcfe, which was higher than the nine months ended September 30, 2006 as a result of our drilling program and operational improvements, along with the acquisition of our properties in the Cherokee Basin. The acquisition of our properties in the Cherokee Basin contributed 2.4 Bcfe of the increase. We hedged approximately 89% of our actual production through September 2007. As discussed below, the loss from our mark-to-market activities increased $2.7 million for the nine months ended September 30, 2007, as compared to the nine months ended September 30, 2006. 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 nine months ended September 30, 2006. However, in conjunction with the EnergyQuest Acquisition, the Amvest Acquisition, and the Newfield Acquisition, we entered into derivative transactions to hedge a portion of the future expected production associated with these acquisitions, before the acquisitions closed. These derivatives were accounted for as mark-to-market derivatives and were recorded at fair value in our financial statements until June 18, 2007 for EnergyQuest and until August 20, 2007 for Amvest, at which time the swaps were designated as cash flow hedges and began receiving cash flow accounting treatment. The Newfield derivative transactions are still accounted for as mark-to-market derivatives. For the nine months ended September 30, 2007, the unrealized mark-to-market loss was $2.8 million. The put options related to the production from the EnergyQuest Assets and the Newfield derivatives 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 nine months ended September 30, 2007, we recognized a loss of approximately $1.5 million related to hedge ineffectiveness. Hedge settlements were $11.1 million for the nine months ended September 30, 2007.

Field operating expenses. For the nine months ended September 30, 2007, field operating expenses increased $5.3 million, or 144.0%, to $11.9 million, compared to expenses of $6.6 million for the nine months ended September 30, 2006. This increase was primarily the result of maintenance costs in the Black Warrior Basin during the nine months ended September 30, 2007, along with the costs of operating the properties acquired in the Cherokee Basin. Our per unit costs decreased from $1.96 per Mcfe in 2006 to $1.94 per Mcfe in 2007 because of operational efficiencies gained during the year and higher production volumes. Cost of sales was $0.7 million for the nine months ended September 30, 2007, which represents the cost of purchased natural gas in the Cherokee Basin.

General and administrative expenses. General and administrative expenses increased $2.6 million, or 75.8%, to $6.0 million for the nine months ended September 30, 2007, as compared to the nine months ended September 30, 2006. This increase was primarily due to the increased expenses related to being a public company, expenses associated with the transition services agreements with EnergyQuest, Amvest, and Newfield, expenses related to acquisition and integration costs associated with our recent acquisitions, $0.2 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 nine months ended September 30, 2007 was $13.2 million, or $2.13 per Mcfe, compared to $5.9 million, or $1.77 per Mcfe, for the nine months ended September 30, 2006. This increase reflects our increased production volumes, asset acquisitions, and the increased basis in our assets resulting from additional capital expenditures between September 30, 2006 and September 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 nine months ended September 30, 2007 increased $4.2 million as compared to approximately $2,000 in interest expense for the nine months ended September 30, 2006. This increase was due to the borrowings under our reserve-based credit facility, which we entered into on October 31, 2006. At September 30, 2007, we had an outstanding balance under the credit facility of $147.0 million. Interest expense was partially offset by $0.1 million of gain realized on an interest rate swap that was terminated in June 2007.

Interest income. Interest income was $0.3 million for the nine months ended September 30, 2007, compared to $0.4 million for the nine months ended September 30, 2006. During the nine months ended September 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 September 30, 2007, the balance was $12.7 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 change in Accumulated other comprehensive income is shown in our consolidated statements of operations and comprehensive income as a gain of $3.2 million for the three months ended September 30, 2007, and as a loss of $0.4 million for the nine months ended September 30, 2007.

Liquidity and Capital Resources

During the nine months ended September 30, 2007, we utilized proceeds from credit facility borrowings, equity financing and cash flow from operations as our primary sources of capital. As of September 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. On July 26, 2007, our borrowing base was increased to $180.0 million. At September 30, 2007, we had $147.0 million of debt outstanding under the reserve-based credit facility and $33.0 million in unused borrowing capacity. During 2007, we have issued new units to private investors for approximately $375.0 million and have used these proceeds to finance our acquisitions in the Cherokee Basin.

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. On October 24, 2007, we announced a cash distribution for the third quarter ending September 30, 2007, of $0.5625 per unit, or $2.25 per unit on an annualized basis, for all of our outstanding common and Class A units. The distribution will be payable on November 14, 2007, to unitholders of record at the close of business on November 7, 2007. The increase in the distribution rate will commence a management incentive interest vesting period under our operating agreement. An initial cash reserve of $0.1 million has been established to fund future distributions on the management incentive interests. Although the management incentive vesting period has commenced, we are not able to predict whether we will ultimately 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 ultimately 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 $180.0 million, on July 26, 2007. 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. As of September 30, 2007, we had borrowed $147.0 million under the reserve-based credit facility.

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.

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 September 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 the LIBOR rate at 4.74%, 4.964%, and 4.805% on $16.5 million, $45.0 million, and $29.5 million, respectively, of our outstanding debt through February 20, 2010, September 20, 2010, and October 19, 2010, respectively.

Cash Flow from Operations

Our net cash flow provided by operating activities for the nine months ended September 30, 2007 was $33.3 million, compared to net cash flow provided by operating activities of $14.3 million for the same period in 2006. This increase in operating cash flow was primarily attributable to higher sales of oil and natural gas as a result of our acquisitions in the Cherokee Basin.

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 September 30, 2007 were:

Fixed Price Swaps

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

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

Put Options

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

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

Fixed Price Swaps

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

Swaptions

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

Investing Activities—Acquisitions and Capital Expenditures

Cash used in investing activities was $499.7 million for the nine months ended September 30, 2007, compared to $22.7 million for the nine months ended September 30, 2006. Our capital expenditures were $17.7 million for the nine months ended September 30, 2007, which primarily related to $16.3 million for drilling and development of oil and natural gas properties and $1.4 million in expenditures on materials and supplies. We drilled and completed 20 gross wells (20 net wells) during this nine month period in the Black Warrior Basin and 34 net wells and 20.5 net recompletions in the Cherokee Basin. For the nine months ended September 30, 2007, we completed the EnergyQuest, Amvest, and Newfield acquisitions for approximately $482.5 million, which is net of cash acquired and the Amvest drilling fund. During the nine months ended September 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 $29.0 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, the Amvest drilling fund, 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 $478.5 million for the nine months ended September 30, 2007, compared to $63,000 used in financing activities for the nine months ended September 30, 2006. We borrowed $131.0 million from our reserve-based credit facility in order to complete the EnergyQuest, Amvest, and Newfield acquisitions and for investment capital spending in the Black Warrior and Cherokee Basins. We also issued $375.0 million of common units before estimated offering expenses and fees. We retired $6.0 million in debt in August 2007. We also have paid distributions of $15.7 million to our common and Class A unitholders and on the Class D interests during 2007.

Contractual Obligations

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

	Payments Due By Year(1)(2) (In 000's)						
	2007	2008	2009	2010	2011	Thereafter	Total
Management Services Agreement (3)	$361	$—	$—	$ —	$—	$ —	$ 361
Reserve-Based Credit Facility	—	—	—	147,000	—	—	147,000
Support Services Agreement	120	140	—	—	—	—	260
Purchase Obligation	185	—	—	—	—	—	185
Total	$666	$140	$—	$147,000	$—	$ —	$147,806

(1) This table does not include any liability associated with derivatives.
(2) This table does not include interest as interest rates are variable.
(3) We expect to have obligations under the Management Services Agreement in 2008 but the amount has not been determined as of September 30, 2007.

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 EnergyQuest , Amvest, and Newfield acquisitions.

Production, Drilling, and Capital Expenditures

In 2007, we expect our net production to be between 10.1 Bcfe and 11.1 Bcfe. 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 95 to 105 newly drilled wells and recompletions in the Black Warrior Basin and in the Cherokee Basin. Excluding the impact of additional acquisitions, we expect to spend between $25.0 million and $29.0 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 and in early 2008.

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. We also expect that oil prices will continue increasing to record levels during the remainder of 2007.

We have entered into derivative positions to mitigate the impact of lower natural gas prices on our operations and cash flows. Our derivative positions are outlined on page 25. All of our derivative positions, except our puts, swapations, and the Newfield swaps, are treated as cash flow hedges for accounting purposes. The puts, swapations, and the Newfield swaps derivatives are accounted for as mark-to-market activities. We also have hedged our exposure to changes in LIBOR on the interest payments associated with $109.5 million of our outstanding debt. For accounting purposes, our interest rate swaps are treated as cash flow hedges.

Operating Expenses: Lease Operating Expenses, Cost of Sales, 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), cost of sales (gas purchases and gathering charges), 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 $28.5 million and $30.5 million. This amount does not include any expenses associated with cost of sales for gas purchases and gathering charges. 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.

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 September 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.

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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 Black Warrior Basin in Alabama 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					
September 30, 2007	$ 11,917	$ 3,027	$ (8,890)	$ 17,451	$5,534

Interest Rate Risk

At September 30, 2007, we had debt outstanding of $147.0 million, which incurred interest at a rate of LIBOR plus an applicable margin between 1.25% and 2.00% based on utilization. At September 30, 2007, the three-month LIBOR interest rate was 5.49%. 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%, 4.964%, and 4.805% on $16.5 million, $45.0 million, and $29.5 million, respectively, of our outstanding debt through February 20, 2010, September 20, 2010, and October 19, 2010, respectively. At September 30, 2007, the carrying value and fair value of our debt is $147.0 million.

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

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Increase	Fair Value	(Decrease)
			(in 000's)		
Impact of changes in LIBOR on derivative interest rate instruments					
September 30, 2007	$ 654	$ 914	$ 261	$ 394	$ (261)

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 September 30, 2007, there were no changes 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 have materially affected, or are reasonably likely to materially affect, CEP's internal control over financial reporting other than as discussed below.

In the third quarter 2007, we entered into a contract with College Station Financial ("CSF"), a wholly-owned subsidiary of Schlumberger LTD , to handle certain accounting functions for our properties in the Cherokee Basin. CSF manages the cash flow of our assets, including the payment of invoices, the calculation and payment of royalties, and the receipt of the revenues from gas sales, and provides entries that are used to generate financial statements by us. The transition of these functions to CSF has required revisions to our internal control over financial reporting. We reviewed the transition, as well as the controls affected by the transition, and made appropriate changes to affected internal controls.

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.

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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 September 2007, we acquired 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 other intangible assets, asset devaluation or restructuring charges; unforeseen difficulties encountered in operating in new geographic areas; an increase in our costs or a decrease in our revenues associated with any potential royalty owner or landowner claims or disputes; and customer or key employee losses at the acquired businesses.

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

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

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 Black Warrior Basin do not typically increase as the formation dewaters.

Our production from reserves in the Black Warrior Basin 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 September 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.

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 are seeking to terminate the Trust, which termination could reduce our future revenues and adversely affect our results of operations and our ability to pay cash distributions.

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

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

We hold natural gas leases in the Black Warrior Basin 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 Black Warrior Basin 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 Black Warrior Basin and in the Cherokee Basin. These identified drilling locations represent a significant part of our future development drilling program. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, natural gas prices, costs and drilling results. In addition, no proved reserves are assigned to any of the potential drilling locations we have identified and therefore, there may be greater uncertainty with respect to the likelihood of drilling and completing successful commercial wells at these potential drilling locations. Our final determination of whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified, which could have a significant adverse effect on our financial condition and results of operations.

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 29% of the outstanding limited liability company interests of CEP as of October 31, 2007. 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.

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

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

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

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

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

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

Because a common unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and he may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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," "pursue," "target," "continue," 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.

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

We held a special annual meeting of our common unitholders on October 12, 2007 at which our common unitholders approved a proposal to approve a change in the terms of our Class F units to permit the conversion of all outstanding Class F units into the same number of our common units and the issuance of additional common units in such amount upon such conversion (the "Class F Conversion and Issuance Proposal"), as follows:

	Votes For	Votes Against	Abstained
Class F Conversion and Issuance Proposal	8,266,866	3,767	232

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 nine months ended September 30, 2007 and September 30, 2006

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

Consolidated Statements of Cash Flows—Constellation Energy Partners LLC for the nine months ended September 30, 2007 and September 30, 2006

Consolidated Statements of Changes in Members' Equity and Comprehensive Income—Constellation Energy Partners LLC for the nine months ended September 30, 2007

Notes to Consolidated Financial Statements

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EXHIBIT INDEX

Exhibit Number		Description
2.1	—	Purchase and Sale Agreement dated as of August 2, 2007, between Newfield Exploration Mid-Continent Inc. and Constellation Energy Partners LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
2.2	—	Nominee Agreement, dated as of September 21, 2007, by and between Newfield Exploration Mid-Continent Inc. and CEP Mid-Continent LLC (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
3.1	—	Certificate of Formation of Constellation Energy Partners LLC, as amended (incorporated herein by reference to Exhibit 3.1 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 12, 2007).
3.2	—	Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006).
3.3	—	Amendment No. 1 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007).
3.4	—	Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007).
3.4	—	Amendment No. 3 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC dated September 21, 2007 (incorporated by reference to Exhibit 3.5 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
4.1	—	Registration Rights Agreement, dated September 21, 2007, by and between Constellation Energy Partners LLC and the purchasers named therein (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
10.1	—	Common Unit Purchase Agreement, dated August 2, 2007, by and between Constellation Energy Partners LLC and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
*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 Chief 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

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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: November 14, 2007	By	/s/ Angela A. Minas
		Chief Financial Officer, Chief Accounting Officer And Treasurer

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* Filed herewith

Exhibit 31.1

CONSTELLATION ENERGY PARTNERS LLC

CERTIFICATION

I, Felix J. Dawson, certify that:

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

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

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

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

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

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

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

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

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

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

Date: November 14, 2007

/s/ Felix J. Dawson

Felix J. Dawson
Chairman of the Board, Chief Executive Officer and President

Exhibit 31.2

CONSTELLATION ENERGY PARTNERS LLC

CERTIFICATION

I, Angela A. Minas, certify that:

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

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

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

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

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

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

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

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

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

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

Date: November 14, 2007

/s/ Angela A. Minas

Angela A. Minas
Chief Financial Officer, Chief Accounting Officer and Treasurer

Exhibit 32.1

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

I, Felix J. Dawson, Chairman of the Board, Chief Executive Officer and President of Constellation Energy Partners LLC, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Quarterly Report on Form 10-Q for the quarter ended September 30, 2007 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

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

/s/ Felix J. Dawson

Felix J. Dawson
Chairman of the Board, Chief Executive Officer and President

Date: November 14, 2007

Exhibit 32.2

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

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

(i) The accompanying Quarterly Report on Form 10-Q for the quarter ended September 30, 2007 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

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

/s/ Angela A. Minas

Angela A. Minas
Chief Financial Officer, Chief Accounting Officer
and Treasurer

Date: November 14, 2007