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 June 30, 2008

OR

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

For the transition period from to .

Commission File Number 001-33147

Constellation Energy Partners LLC
(Exact Name of Registrant as Specified in Its Charter)

Delaware **(State of organization)**	**11-3742489** **(I.R.S. Employer Identification No.)**
100 Constellation Way **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, a non-accelerated filer, or a smaller reporting company. 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 ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

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

Common Units outstanding on July 31, 2008: 21,915,110 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 (Loss)

(Unaudited)

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(In 000's except unit data)			
Revenues				
Oil and gas sales	$ 38,994	$ 15,190	$ 71,382	$ 26,497
Loss from mark-to-market activities (see Note 5)	(15,033)	(2,619)	(17,989)	(5,401)
Total revenues	23,961	12,571	53,393	21,096
Expenses:				
Operating expenses:				
Lease operating expenses	9,209	3,150	18,273	4,745
Cost of sales	2,239	—	3,387	—
Production taxes	2,885	685	4,550	1 144
General and administrative	3,787	1,771	7,122	3,390
Loss (gain) on sale of asset	—	(1)	(211)	94
Depreciation, depletion, and amortization	11,489	3,584	21,022	5,543
Accretion expense	101	77	202	113
Total operating expenses	29,710	9,266	54,345	15,029
Other expenses (income)				
Interest expense	3,102	1,266	5,662	1,825
Interest income	(43)	(84)	(284)	(135)
Other (income)	(18)	(70)	(4)	(70)
Total other expenses (income)	3,041	1,112	5,374	1,620
Total expenses	32,751	10,378	59,719	16,649
Net income (loss)	$ (8,790)	$ 2,193	$ (6,326)	$ 4,447
Other comprehensive income (loss)	(94,813)	6,175	(143,062)	(3,605)
Comprehensive income (loss)	$ (103,603)	$ 8,368	$ (149,388)	$ 842
Earnings per unit				
Earnings (loss) per unit—Basic	$ (0.39)	$ 0.17	$ (0.28)	$ 0.36
Units outstanding—Basic	22,351,353	13,072,577	22,349,517	12,201,279
Earnings (loss) per unit—Diluted	$ (0.39)	$ 0.17	$ (0.28)	$ 0.36
Units outstanding—Diluted	22,351,353	13,072,577	22,349,517	12,201,279
Distributions declared and paid per unit	$ 0.5625	$ 0.4625	$ 1.1250	$ 0.6736

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

	June 30, 2008 (Unaudited)	December 31, 2007
	(In 000's)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 17,614	$ 18,689
Accounts receivable	24,948	18,519
Prepaid expenses	1,277	554
Risk management assets (see Note 5)	—	7,734
Other	4	377
Total current assets	43,843	45,873
Natural gas properties (see Note 7)		
Natural gas properties, equipment and facilities	744,839	675,144
Material and supplies	3,126	2,880
Less accumulated depreciation, depletion and amortization	(54,822)	(34,371)
Net natural gas properties	693,143	643,653
Other assets		
Debt issue costs (net of accumulated amortization of $954 at June 30, 2008 and $443 at December 31, 2007)	2,340	1,449
Risk management assets (see Note 5)	—	2,185
Other non-current assets	12,731	13,495
Total assets	$ 752,057	$ 706,655
LIABILITIES AND MEMBERS' EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 3,016	$ 1,933
Payable to affiliate	959	2,813
Accrued liabilities	15,187	12,315
Environmental liabilities	317	546
Risk management liabilities (see Note 5)	61,667	—
Royalty payable	6,630	2,944
Total current liabilities	87,776	20,551
Other liabilities		
Asset retirement obligation	6,474	6,163
Risk management liabilities (see Note 5)	100,124	10,539
Debt	216,000	153,000
Total other liabilities	322,598	169,702
Total liabilities	410,374	190,253
Commitments and contingencies (see Note 9)		
Class D Interests	6,667	7,000
Members' equity		
Class A units, 447,247 and 447,022 shares authorized, issued and outstanding, respectively	9,476	10,104
Class B units, 22,348,763 and 22,348,763 shares authorized, respectively, and 21,915,110 and 21,904,106 shares issued and outstanding, respectively	464,378	495,074
Accumulated other comprehensive income (loss)	(138,838)	4,224
Total members' equity	335,016	509,402
Total liabilities and members' equity	$ 752,057	$ 706,655

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(In 000's)	
Cash flows from operating activities:		
Net income (loss)	$ (6,326)	$ 4,447
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	21,022	5,543
Amortization of debt issuance costs	511	172
Accretion of plugging and abandonment liability	202	113
Equity earnings in affiliate	(4)	(70)
(Gain) loss from disposition of property and equipment	(211)	94
Hedge ineffectiveness	(159)	(174)
Loss from mark-to-market activities	17,989	5,401
Long-term incentive plan	155	—
Changes in Assets and Liabilities:		
Change in net risk management assets and liabilities	280	(1,305)
(Increase) decrease in accounts receivable	(6,455)	(108)
(Increase) decrease in prepaid expenses	(384)	59
(Increase) decrease in other assets	401	(1,995)
Increase (decrease) in accounts payable	1,082	2,998
Increase (decrease) in payable to affiliate	(1,854)	(1,014)
Increase (decrease) in accrued liabilities	2,322	1,039
Increase (decrease) in royalty payable	3,686	632
Net cash provided by operating activities	32,257	15,832
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash acquired	(50,379)	(114,896)
Development of natural gas properties	(19,396)	(10,998)
Proceeds from sale of equipment	472	181
Distributions from equity affiliate	223	100
Net cash used in investing activities	(69,080)	(125,613)
Cash flows from financing activities:		
Members' distributions	(25,485)	(9,043)
Proceeds from issuance of debt	220,000	60,500
Repayment of debt	(157,000)	—
Costs for shelf registration statement	(340)	—
Proceeds from equity issuance	—	58,770
Debt issue costs	(1,427)	(263)
Net cash provided by financing activities	35,748	109,964
Net increase (decrease) in cash	(1,075)	183
Cash and cash equivalents, beginning of period	18,689	7,485
Cash and cash equivalents, end of period	$ 17,614	$ 7,668
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 311	$ 1,266
Cash received during the period for interest	$ 322	149
Cash paid during the period for interest	$ (5,049)	$ (912)

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 (Loss)	Total Members' Equity
	Units	Amount	Units	Amount		
	(In 000's, except unit amounts)					
Balance, January 1, 2008	447,022	$ 10,104	21,904,106	$ 495,074	$ 4,224	$ 509,402
Distributions	—	(504)	—	(24,649)	—	(25,153)
Change in fair value of commodity hedges	—	—	—	—	(136,701)	(136,701)
Cash settlement of commodity hedges	—	—	—	—	(5,878)	(5,878)
Change in fair value of interest rate hedges	—	—	—	—	(483)	(483)
Long-term incentive program	225	2	11,004	153	—	155
Net income (loss)	—	(126)	—	(6,200)	—	(6,326)
Balance, June 30, 2008	447,247	$ 9,476	21,915,110	$ 464,378	$ (138,838)	$ 335,016

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

The consolidated financial statements as of, and for the period ended June 30, 2008, 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, 2007. Certain amounts in the consolidated financial statements and notes thereto have been reclassified to conform to the 2008 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 acquisition of our properties in the Black Warrior Basin 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”). CEP completed its initial public offering on November 20, 2006, and is traded on the NYSE Arca under the symbol “CEP”. CEP is partially-owned by Constellation Energy Commodities Group, Inc. (“CCG”), which is owned by Constellation Energy Group, Inc. (NYSE: CEG) (“Constellation” or “CEG”). As of June 30, 2008, affiliates of Constellation own all of the Company’s Class A units, approximately 27% of the Company’s common units, and all of the Company’s Class D interests.

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

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, 2007.

Earnings per Unit

Basic earnings per unit (“EPS”) are computed by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. At June 30, 2008, we had 447,247 Class A units and 21,915,110 Class B units outstanding. Of the Class B units, 11,004 units represent restricted unvested common units granted and outstanding.

The following table presents earnings (loss) per common unit amounts:

For the three months ended June 30, 2008	Income (loss)	Weighted Average Units	Per Unit Amount
	(In 000’s except unit and per unit data)		
Basic EPS:			
Income (loss) allocable to unitholders	$ (8,790)	22,351,353	$ (0.39)
Effect of dilutive securities:			
Restricted common units—Treasury stock method	—	—	—
Diluted EPS:			
Income (loss) allocable to common unitholders	$ (8,790)	22,351,353	$ (0.39)

For the six months ended June 30, 2008	Income (loss)	Weighted Average Units	Per Unit Amount
	(In 000's except unit and per unit data)		
Basic EPS:			
Income (loss) allocable to unitholders	$ (6,326)	22,349,517	$ (0.28)
Effect of dilutive securities:			
Restricted common units—Treasury stock method	—	—	—
Diluted EPS:			
Income (loss) allocable to common unitholders	$ (6,326)	22,349,517	$ (0.28)

No restricted common units are included in diluted EPS for the three months and six months ended June 30, 2008, as the Company reported a net loss.

3. NEW ACCOUNTING PRONOUNCEMENTS

In March 2008, the FASB issued SFAS 161, *Disclosures About Derivative Instruments and Hedging Activities*. SFAS 161 is effective beginning January 1, 2009 and requires entities to provide expanded disclosures about derivative instruments and hedging activities including (1) the ways in which an entity uses derivatives, (2) the accounting for derivatives and hedging activities, and (3) the impact that derivatives have (or could have) on an entity's financial position, financial performance, and cash flows. SFAS 161 requires expanded disclosures and does not change the accounting for derivatives. CEP is currently evaluating the impact of SFAS No. 161, but we do not expect the adoption of this standard to have a material impact on our financial statements.

In March 2008, the Emerging Issues Task Force reached a consensus on Issue No. 07-4, or EITF 07-4, *Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships*. EITF 07-4 provides guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. This Issue is effective for fiscal years beginning after December 15, 2008 (January 1, 2009 for us), and interim periods within those fiscal years. Earlier application is not permitted, and the guidance in this Issue is to be applied retrospectively for all financial statements presented. CEP is currently evaluating the impact of this Issue on our financial statements.

4. ACQUISITIONS

CoLa Acquisition

On March 31, 2008, the Company acquired 83 non-operated producing oil and natural gas wells in the Woodford Shale in the Arkoma Basin in Oklahoma from CoLa Resources LLC ("CoLa") for $53.4 million, subject to purchase price adjustments ("CoLa Acquisition"). CoLa is an affiliate of CEG, the Company's sponsor. The transaction was reviewed and approved by the Company's conflicts committee. In its review, the Company's conflicts committee considered various economic factors (including historical and estimated future production, estimated proved reserves, future pricing estimates and operating cost estimates) regarding the transaction, and determined that the acquisition was fair and in the best interests of the Company. The 83 wells, located in Coal and Hughes Counties, Oklahoma, have an average gross working interest per well of 11.5% and an average net revenue interest per well of 9.2%. The acquired oil and natural gas reserves associated with the wells are 100% proved developed producing. Our results of operations include the results of the CoLa wells after the date of acquisition.

To fund the purchase of CoLa, the Company borrowed $53.0 million under its reserve-based credit facilities (see Note 6).

Upon the announcement of the acquisition, the Company entered into derivative transactions to hedge a portion of the future expected production associated with these wells. See Note 5 for a discussion of mark-to-market activities.

The total consideration paid was $52.3 million which consisted of $52.4 million in cash and transaction costs and assumed liabilities of approximately $0.1 million, primarily associated with asset retirement obligations on the properties. The following table summarizes the preliminary allocation of the purchase price to the assets acquired and liabilities assumed at the date of acquisition.

Acquired March 31, 2008	(in millions)
Natural gas properties, equipment and facilities	$ 52.4
Total assets acquired	52.4
Asset retirement obligations	(0.1)
Net assets acquired	$ 52.3

The preliminary purchase price allocation is based on evaluations of proved oil and natural gas reserves, discounted cash flows, quoted market prices, and other estimates by management. The purchase price allocation related to the CoLa acquisition is preliminary and subject to change, pending final valuation of the assets and liabilities acquired and any post-closing or title adjustments.

A post-closing adjustment occurred on July 29, 2008, to settle certain items including the revenue distributions and certain expenses associated with the oil and gas properties on or after the effective date of January 1, 2008. See Note 16 for additional information. In addition, under the purchase agreement, the Company will have the right to assert, and CoLa will have the right to attempt to cure, any title defects to the acquired wells until July 31, 2009. CoLa's post-closing payment obligations with respect to title defects and indemnities under the purchase agreement is secured, in part, by a guaranty from CCG delivered at closing. The maximum amount of the CCG guaranty is limited to (i) 20% of the purchase price, with respect to indemnity obligations, and (ii) with respect to title defect obligations, the amount of such title defects, such amount to be calculated as provided in the purchase agreement. The amount of CCG's guaranty with respect to title defect obligations will decrease as title curative is received or CoLa receives proceeds of production from wellbores as to which payments of production proceeds had not commenced as of the closing date and which are attributable to periods prior to the effective time of the purchase agreement. Under certain circumstances, identified title defects may result in a purchase price adjustment.

Pro Forma Results

The unaudited pro forma results presented below for the three months ended June 30, 2008 and 2007 and the six months ended June 30, 2008 and 2007 have been prepared to give effect to the CoLa Acquisition described above, our 2007 acquisitions of oil and natural gas properties and other interests from EnergyQuest Resources LP ("EnergyQuest Acquisition"), and Newfield Exploration Mid-Continent Inc. ("Newfield Acquisition") and our 2007 acquisition of Amvest Osage, Inc. ("Amvest Acquisition") on our results of operations as if these acquisitions had been consummated at the beginning of the periods presented. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if this acquisition had been completed on such date or to project our results of operations for any future date or period.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Unaudited) (In 000's, except per share data)			
Pro forma financial results:				
Revenue	$ 23,960	$ 29,930	$ 56,726	$ 58,119
Income (loss) from operations	(5,748)	6,287	(189)	12,521
Net income (loss)	(9,663)	3,024	(7,199)	5,680
Basic earnings (loss) per share	$ (0.43)	$ 0.14	$ (0.32)	$ 0.26
Diluted earnings (loss) per share	$ (0.43)	$ 0.14	$ (0.32)	$ 0.26

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 2013. The value of the cash flow hedges for natural gas included in Accumulated other comprehensive income (loss) on the Consolidated Balance Sheets was an unrecognized loss of approximately $135.6 million and an unrecognized gain of $1.5 million at June 30, 2008 and December 31, 2007, respectively. The Company expects that $58.0 million of the unrecognized loss will be reclassified from Accumulated other comprehensive income (loss) to the income statement in the next twelve months. There was approximately $0.2 million of income as a result of hedge ineffectiveness for both of the six month periods ended June 30, 2008, and June 30, 2007.

At June 30, 2008 and December 31, 2007, the Company had debt outstanding of $216.0 million and $153.0 million, respectively, under its reserve-based credit facilities. The Company has entered into hedging arrangements in the form of interest rate swaps to reduce the impact of volatility of changes in the London interbank offered rate ("LIBOR") on $109.5 million of the outstanding debt through October 2010. The interest rate swaps have termination dates between February 20, 2010 and October 19, 2010. The swaps have been designated as cash flow hedges of the risk associated with changes in the designated benchmark interest rate (in this case, LIBOR) related to forecasted payments associated with interest on the reserve-based credit facilities. The Company assesses and records ineffectiveness for the interest rate swaps in accordance with the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. There was no hedge ineffectiveness identified related to the interest rate swaps. The value of the Company's cash flow hedges for interest rates included in Accumulated other comprehensive income (loss) was an unrecognized loss of approximately $3.2 million at June 30, 2008 and an unrecognized loss of $2.7 million at December 31, 2007.

Mark-to-Market Activities

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

For the six months ended June 30, 2008 and 2007, the Company recognized a mark-to-market loss of approximately $18.0 million and $5.4 million, respectively, in connection with these positions. At June 30, 2008 and December 31, 2007, the fair value of the derivatives accounted for as mark-to-market activities amounted to a net liability of approximately $13.6 million and a net asset of approximately $2.2 million, respectively.

SFAS 157

Effective January 1, 2008, we adopted SFAS 157, *Fair Value Measurements* for financial assets and liabilities measured on a recurring basis. SFAS 157 defines fair value, establishes a framework for measuring fair value and requires certain disclosures about fair value measurements for assets and liabilities measured on a recurring basis. In February 2008, the FASB issued FSP No. 157-2, which delayed the effective date of SFAS 157 by one year for non-financial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We have elected to utilize this deferral and have only partially applied SFAS 157 (to financial assets and liabilities measured at fair value on a recurring basis, as described above). Accordingly, we will apply SFAS 157 to our nonfinancial assets and liabilities for which we disclose or recognize at fair value on a nonrecurring basis, such as asset retirement obligations and other assets and liabilities in the first quarter of 2009. Fair value is the exit price that we would receive to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date.

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

- Level 1 – Quoted prices available in active markets for identical assets or liabilities as of the reporting date.
- Level 2 – Pricing inputs other than quoted prices in active markets included in Level 1 which are either directly or indirectly observable as of the reporting date. Level 2 consists primarily of non-exchange traded commodity derivatives.
- Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources.

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

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

The following table sets forth by level within the fair value hierarchy the Company's assets and liabilities that were measured at fair value on a recurring basis as of June 30, 2008.

At June 30, 2008	Level 1	Level 2	Level 3	Netting and Cash Collateral*	Total Net Fair Value
			(In thousands)		
Risk management assets	—	—	—	—	—
Risk management liabilities	—	$123,365	$38,426	—	$ 161,791
Total	—	$123,365	$38,426	—	$ 161,791

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

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

The valuation of our derivatives is performed by Constellation under a management services agreement (see Note 8). In order to determine the fair value amounts presented above, Constellation utilizes various factors, including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and parental guarantees), but also the impact of our nonperformance risk on our liabilities. We use our reserve-based credit facilities, or guarantees from Constellation, to provide credit support for our derivative transactions. As a result, we do not post cash collateral with our counterparties.

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

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

	Three Months Ended June 30, 2008 (In thousands)	*Six Months Ended June 30, 2008 (In thousands)*
Balance at beginning of period	$ (9,246)	$ (3,591)
Realized and unrealized gains (losses):		
Included in earnings	(8,727)	(8,945)
Included in other comprehensive income	(18,807)	(24,613)
Purchases, sales, issuances, and settlements	(1,646)	(1,277)
Transfers into and out of Level 3	0	0
Balance as of June 30, 2008	$ (38,426)	$ (38,426)
Change in unrealized gains (losses) relating to derivatives still held as of June 30, 2008	$ (29,008)	$ (34,855)

Credit Support Fee Agreements

In February 2008, in connection with the CoLa Acquisition, we entered into a credit support fee agreement with Constellation under which Constellation guaranteed credit support up to $8.5 million for certain financial derivatives that we entered into with BNP and SocGen. These guarantees were obtained because we did not own the assets at the time the derivatives were entered into and we could not use our existing reserve-based credit facility to provide collateral for the derivative transactions. These guarantees have been released. Through June 30, 2008, Constellation charged us $0.1 million for this credit support.

Fair Value of Non-Risk Management Assets and Liabilities

At June 30, 2008, the carrying values of cash and cash equivalents, accounts receivable, other current assets, and current liabilities on the Consolidated Balance Sheets approximate fair value because of their short term nature. The Company believes the carrying value of long-term debt approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms.

6. DEBT

Reserve-Based Credit Facilities

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

New Credit Agreement

On March 28, 2008, the Company entered into a new $500.0 million secured credit agreement ("Credit Facility") with The Royal Bank of Scotland plc as administrative agent (the "Administrative Agent") and a syndicate of lenders. The amount available for borrowing at any one time is limited to the borrowing base for the Company's properties other than in the State of Alabama, which was initially set at $150.0 million. The borrowing base will be re-determined semi-annually by the lenders in their sole discretion based on reserve reports as prepared by reserve engineers, together with, among other things, the natural gas and oil prices at such time. Any increase in each borrowing base must be approved by all of the lenders. Under certain conditions, the credit facility may be increased up to an additional $250.0 million. The Credit Facility matures on October 31, 2010.

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

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

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

In addition, the Company is required to maintain (i) a ratio of debt to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets, (gain) loss or sale of assets, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on natural gas derivatives and realized (gain) loss on cancelled natural gas derivatives, and other similar charges) of not more than 3.50 to 1.00; (ii) Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and (iii) consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities, of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143, *Accounting for Asset Retirement Obligations* (including the current liabilities in respect of the termination of natural gas and interest rate swaps). All financial covenants are calculated using CEP's consolidated financial information.

The Credit Facility also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, guaranties not being valid under the Credit Facility and a change of control. If an event of default occurs under the credit facility, the lenders will be able to accelerate the maturity of the Credit Facility and exercise other rights and remedies.

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

On March 28, 2008, the Company borrowed $131.0 million under the term loan portion of the Credit Facility. A portion of the proceeds of the borrowings (less associated transaction costs) were used to finance the aggregate consideration for the acquisition of CoLa, and a portion of the proceeds of the borrowings (less associated transaction costs) were used to repay existing indebtedness. During the second quarter 2008, the Company borrowed a net $4.0 million, increasing the total borrowings under the credit facility to $135.0 million.

Amended and Restated Credit Agreement

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

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

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

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

In addition, the Company is required to maintain (i) a ratio of debt to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets, (gain) loss or sale of assets, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on natural gas derivatives and realized (gain) loss on cancelled natural gas derivatives, and other similar charges) of not more than 3.50 to 1.00; (ii) Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and (iii) consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities, of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143, *Accounting for Asset Retirement Obligations* (including the current liabilities in respect of the termination of natural gas and interest rate swaps). All financial covenants are calculated using CEP's consolidated financial information.

The Amended and Restated Credit Facility also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, guaranties not being valid under the Amended and Restated Credit Facility and a change of control. If an event of default occurs under the credit facility, the lenders will be able to accelerate the maturity of the Amended and Restated Credit Facility and exercise other rights and remedies.

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

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

CEP's obligations under these two credit facilities are secured by mortgages on our natural gas properties, as well as a pledge of all ownership interests in our subsidiaries. Debt issue costs incurred through June 30, 2008, were approximately $3.3 million and will be amortized over the life of the facilities. As of June 30, 2008 and December 31, 2007, the Company had $216.0 million and $153.0 million, respectively, in outstanding debt under its reserve-based credit facilities. As of June 30, 2008, the Company had $24.0 million in available borrowing capacity under the reserve-based credit facilities.

7. NATURAL GAS PROPERTIES

Natural gas properties consist of the following:

	June 30, 2008	December 31, 2007
	(In 000's)	
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$704,850	$ 635,224
Unproved property	39,077	39,018
Total property costs	$743,927	674,242
Materials and supplies	3,126	2,880
Land	912	902
Total	747,965	678,024
Less: Accumulated depreciation, depletion and amortization	(54,822)	(34,371)
Oil and natural gas properties and equipment, net	$693,143	$ 643,653

In the first quarter of 2008, a fire damaged the Company's field office located in Dewey, Oklahoma. The net book value of the building was $0.2 million. A gain of $0.2 million was recorded for the involuntary conversion as the insurance proceeds of $0.4 million exceeded the book value of the building.

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

Management Services Agreement

In November 2006, CEP entered into a management services agreement with Constellation Energy Partners Management, LLC ("CEPM"), a subsidiary of Constellation, to provide certain management, technical and administrative services. These services include legal, accounting and finance, engineering and technical, risk management, information technology and tax services, as well as acquisition services related to opportunities to acquire oil and natural gas reserves and related midstream assets. CEPM and its affiliates do not have any obligation to provide acquisition services or other services under the management services agreement, provided that CEPM may receive added compensation for providing CEP with services as a result of the management incentive interests it holds in CEP. Each quarter, CEPM charges CEP an amount for services provided to CEP. This amount is agreed to annually and includes a portion of the compensation paid by CEPM and its affiliates to personnel who spend time on CEP's business and affairs. The allocation of compensation expense for the chief executive officer, chief financial officer and chief accounting officer is fixed by agreement between the parties. The allocation of compensation expense for other personnel of CEPM and its affiliates is determined based on the percentage of time spent by such personnel on CEP's business and affairs. The conflicts committee of the Company's board of managers reviews at least annually the services to be provided by CEPM and the costs to be charged to CEP under the management services agreement and reviews the cost allocation quarterly. The conflicts committee also determines if the amounts to be paid by the Company for the services to be performed are fair to and in the best interests of the Company. During the year, the cost allocation may be adjusted upwards to reflect additional services provided by CEPM and its affiliates or downwards to reflect the transition of services to CEP employees. These costs totaled approximately $1.1 million and $0.7 million for the six months ended June 30, 2008 and 2007, respectively. The costs charged to CEP under the management services agreement may be greater or less than the actual costs CEP would incur if the services were performed by an unaffiliated third party.

CEP had a payable to CEPM of $0.7 million and $0.4 million and to CCG of $0.2 million and $2.4 million as of June 30, 2008 and December 31, 2007, respectively. This payable balance is included in current liabilities in the accompanying balance sheets.

Credit Support Fee Agreement

As described further in Note 5, CEG and CEP entered into a credit support fee agreement under which CEG guaranteed credit support for certain financial derivatives with two financial institutions. Through June 30, 2008, CEG charged CEP $0.1 million for the credit support, which is being amortized over the life of the credit support fee agreement.

Natural Gas Purchases

Beginning in September 2007, CCG began purchasing natural gas from CEP in the Cherokee Basin. The arrangement was reviewed by the conflicts committee of CEP's board of managers. The committee found that the arrangement was fair to and in the best interests of CEP. Through July 31, 2009, CEP has an unconditional guarantee from Constellation for payment of up to $8 million for sales made to CCG. Through June 30, 2008, CCG paid CEP $8.7 million for natural gas purchases.

Management Incentive Interests

CEPM holds the management incentive interests in the Company. These management incentive interests represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in the Company's limited liability company agreement) has been achieved and certain other tests have been met. For the six months ended June 30, 2008, none of these applicable tests have been met, and, as a result, CEPM was not entitled to receive any management incentive interest distributions. For the first quarter 2007, the Company increased its distribution rate to $0.4625 per unit. This increase in the distribution rate commenced a management incentive interest vesting period under the Company's operating agreement. A cash reserve of $0.3 million has been established to fund future distributions on the management incentive interests. After the August 15, 2008 distribution, the reserve will be increased from $0.3 million to $0.5 million.

CoLa Acquisition

As further described in Note 4, on March 31, 2008, the Company acquired 83 non-operated producing oil and natural gas wells in the Woodford Shale in the Arkoma Basin in Oklahoma from CoLa for $53.4 million, subject to purchase price adjustments. CoLa is an affiliate of CEG, the Company's sponsor. The transaction was reviewed and approved by the Company's conflicts committee. In its review, the Company's conflicts committee considered various economic factors (including historical and estimated future production, estimated proved reserves, future pricing estimates and operating cost estimates) regarding the transaction, and determined that the transaction was fair to and in the best interests of the Company.

9. COMMITMENTS AND CONTINGENCIES

In the course of its normal business affairs, the Company is subject to possible loss contingencies arising from federal, state and local environmental, health and safety laws and regulations and third-party litigation. As of June 30, 2008 and December 31, 2007, other than the matters discussed below, there were no matters which, in the opinion of management, would have a material adverse effect on the financial position, results of operations or cash flows of CEP.

The Robinson's Bend Field is subject to a net profits interest ("NPI") held by Torch Energy Royalty Trust (the "Trust") (See Note 11). The royalty payment to the Trust is calculated using a sharing arrangement with a pricing formula that has had the effect of keeping our payments to the Trust lower than if such payments had been calculated based on prevailing market prices. CEP is uncertain of the financial impact of the NPI over the life of the Robinson's Bend Field as it has volumetric and price risk variables. However, in order to address a portion of the risk of the potential adverse impact on CEP's operating results from a termination of the sharing arrangement, Constellation Holdings, Inc. ("CHI") contributed $8.0 million to CEP in exchange for all of CEP's Class D interests at the closing of its initial public offering to be used to protect the distributions to the common unit holders in the event the sharing arrangement is terminated. This contribution will be returned to CHI in 24 special quarterly distributions as long as the sharing agreement remains in effect for the distribution period. Distributions of $0.3 million each were paid to the holder of the Company's Class D interests on February 14, 2008, November 14, 2007, August 14, 2007 and May 15, 2007. As a result of the initiation of the arbitration proceeding discussed in Note 11, the Class D interest special quarterly distributions were suspended beginning with the special quarterly cash distributions for the three months ending March 31, 2008 and extending until the final resolution of the arbitration proceeding. See Note 16 for subsequent events related to the arbitration proceeding.

For CEP's 2008 drilling program, CEP has committed to purchase approximately $1.0 million in pipe from a vendor. As of June 30, 2008, CEP had purchased approximately $0.6 million of pipe related to this commitment.

10. ASSET RETIREMENT OBLIGATION

The Company follows SFAS 143, *Accounting for Asset Retirement Obligations.* SFAS 143 requires that the fair value of a liability for an asset retirement obligation ("ARO") be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost ("ARC") is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the ARC is allocated to expense using a systematic and rational method over the asset's useful life. The ARO 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:

	June 30, 2008	December 31, 2007
	(In 000's)	
Asset retirement obligation, beginning balance	$6,163	$ 2,730
Liabilities incurred from acquisition of the properties (Note 4)	56	3,056
Liabilities incurred	53	65
Accretion expense	202	312
Asset retirement obligation, ending balance	$6,474	$ 6,163

At June 30, 2008 and December 31, 2007, 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 Company's wells in the Robinson's Bend Field are subject to a non-operating NPI. The holder of the NPI, the Trust, does not have the right to receive production from the applicable wells in the Robinson's Bend Field. Instead, the Trust only has the right to receive a specified portion of the future natural gas sales revenues from specified wells as defined by the Net Overriding Royalty Conveyance Agreement. The Company records the NPI as an overriding royalty interest net in revenue in the Consolidated Statements of Operations.

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

The Net Proceeds equal the lesser of (i) 95% of the net proceeds from 393 producing wells in the Robinson's Bend Field and (ii) the net proceeds from the sale of 912.5 MMcf of natural gas for the quarter. Net proceeds equal gross proceeds, currently calculated by reference to the gas purchase contract (for a description of the gas purchase contract, please read Item 1. "Business—Natural Gas Data—Torch Royalty NPI—The Gas Purchase Contract" in the Company's Annual Report on Form 10-K for the year ended December 31, 2007), less specified costs attributable to the Robinson's Bend Assets. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (i) of the first sentence of this paragraph (the NPI Net Proceeds Calculation) include: (a) delay rentals, shut-in royalties and similar payments, (b) property, production, severance and similar taxes and related audit charges, (c) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies, (d) certain liabilities for environmental damage, personal injury and property damage, (e) certain litigation costs, (f) costs of environmental compliance, (g) specified operating costs incurred to produce hydrocarbons, (h) specified development costs (including costs to increase recoverable reserves or the timing of recovery of such reserves), (i) costs of specified lease renewals and extensions and unitization costs and (j) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (ii) of the first sentence of this paragraph include: (a) property, production, severance and similar taxes, (b) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies and (c) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. Net proceeds are calculated quarterly and any negative balance (expenses in excess of revenues) within the "net proceeds" calculation accumulates and is charged interest as described above.

The cumulative "Net NPI Proceeds" balance must be greater than $0 before any payments are made to the Trust. The cumulative Net Proceeds was a deficit for the three months ended June 30, 2008 and 2007. As a result, no payments were made to the Trust with respect to the NPI for the six months ended June 30, 2008 and 2007.

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

Termination of the Trust

On January 29, 2008, the unitholders of the Trust voted to terminate the Trust and the trust agreement and authorized the Trustee to wind up, liquidate, and distribute the assets held by the Trust under the terms of the trust agreement. The Oil and Gas Purchase Contract dated as of October 1, 1993 (the "Gas Purchase Contract") by and between Torch Energy Marketing, Inc. ("TEMI"), Torch Royalty Company ("Torch Royalty"), and Velasco Gas Company Ltd., including the portion assigned to us, by its terms, was also terminated on January 29, 2008 as a result of the termination of the Trust.

With the Gas Purchase Contract terminated, we are no longer obligated to sell gas produced from our interest in the Black Warrior Basin pursuant to the Gas Purchase Contract. A dispute arose in January 2008 over whether the termination of the Gas Purchase Contract also terminated the sharing arrangement for purposes of calculating ongoing payments owed to the holder of the NPI. On January 25, 2008, Torch Royalty Company, Torch E&P Company and the Company (collectively, the "Claimants") sent notice of a demand for arbitration before Judicial Arbitration and Mediation Services to Wilmington Trust Company, as Trustee ("Trustee") for the Trust, and to Capital One, NA, as successor to Hibernia National Bank, as trustee for Torch Energy Louisiana Royalty Trust, pursuant to the operative dispute resolution provisions of the agreement governing the Trust, the NPI and the Other NPIs (defined below). The Claimants are working interest owners in certain oil and gas fields located in Texas, Louisiana and Alabama. The working interests owned by the other Claimants are similarly subject to net profit interests (the "Other NPIs") that are also based on the Gas Purchase Contract. In April 2008, Trust Venture Company, LLC ("Trust Venture") was permitted to intervene in the arbitration proceeding under an agreement whereby Trust Venture and its affiliates agreed to be bound by the final award in that proceeding. According to Trust Venture's filings with the Securities and Exchange Commission, Trust Venture owns or controls approximately 75% of the outstanding Trust units.

In the arbitration demand, we and the other Claimants sought a declaratory judgment that the NPI payments, as well as the payments owed in respect of the Other NPIs, will continue to be calculated using the sharing arrangement under the Gas Purchase Contract even though the Trust and the Gas Purchase Contract have been terminated. The Trust and the interveners filed a counter-demand in which they sought a declaratory judgment that, following the termination of the Gas Purchase Contract, the NPI payments will no longer be calculated by reference to the sharing arrangement contained in the Gas Purchase Contract, but instead by reference to the contracts under which production from the Trust Wells is actually sold. See Note 16 for subsequent events related to this arbitration proceeding.

12. ENVIRONMENTAL LIABILITY

The Company is subject to costs resulting from an increasing number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. As of June 30, 2008 and December 31, 2007, accrued environmental obligations were $0.3 million and $0.5 million, respectively. These obligations were classified as current liabilities on CEP's Consolidated Balance Sheet.

13. DISTRIBUTIONS TO UNITHOLDERS

Distributions through June 30, 2008

On May 15, 2008, the Company paid a distribution for the first quarter of 2008 to the unitholders of record at May 8, 2008. The distribution was paid to holders of common units and Class A units at a rate of $0.5625 per unit.

On February 14, 2008, the Company paid a distribution for the fourth quarter of 2007 to the unitholders of record at February 7, 2008. The distribution was paid to holders of common units and Class A units at a rate of $0.5625 per unit. A distribution of $0.3 million was paid to the holder of the Company's Class D interests on February 14, 2008.

Distributions through June 30, 2007

On May 15, 2007, the Company paid a distribution for the first quarter of 2007 to the unitholders of record at May 8, 2007. The distribution was paid to holders of common units, Class A units and Class E units at a rate of $0.4625 per unit. A distribution of $0.3 million was paid to the holder of the Company's Class D interests on May 15, 2007.

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

14. UNIT-BASED COMPENSATION

The Company recognized approximately $155,000 of expense related to its long-term incentive plan's unit-based compensation in the six months ended June 30, 2008.

2008 Grants

The Company granted 11,004 restricted common unit awards on March 1, 2008, to the independent, non-employee members of the Board of Managers. These units had a total fair market value of $225,000 at the grant date. These service-based restricted units will vest in full on March 1, 2009.

See Note 16 for additional information about a restricted common unit award made to certain field employees of the Company on August 1, 2008.

2007 Grants

The Company granted 5,343 restricted common unit awards on September 14, 2007, to the independent, non-employee members of the Board of Managers. These units had a total fair market value of $225,000 at the grant date. This amount was recognized over the vesting period. These restricted common units vested in full on March 1, 2008.

15. MEMBERS' EQUITY

At June 30, 2008, the Company had 447,247 Class A units and 21,915,110 Class B units outstanding, which included 11,004 restricted unvested common units.

At June 30, 2008, the Company had granted 16,347 units of the 450,000 units available under its long-term incentive plan. Of these grants, 5,343 have vested and 11,004 are unvested.

16. SUBSEQUENT EVENTS

Distribution

On July 23, 2008, the Company declared a distribution for the second quarter of 2008 at a rate of $0.5625 per common unit and Class A unit to the unitholders of record at August 7, 2008. The distribution will be paid on August 14, 2008.

As of August 14, 2008, a cash reserve of $0.5 million has been established to fund future distributions on the management incentive interests.

Reserve-Based Credit Facilities

In July 2008, the Company expanded its borrowing base under the $500.0 million Credit Facility from $150.0 million to $175.0 million. The amount available for borrowing at any one time is limited to the borrowing base for the Company's properties other than in the State of Alabama. The borrowing base will be re-determined semi-annually by the lenders in their sole discretion based on reserve reports as prepared by reserve engineers, together with, among other things, the natural gas and oil prices at such time. Any increase in each borrowing base must be approved by all of the lenders. Under certain conditions, the credit facility may be increased up to an additional $225.0 million. The Credit Facility matures on October 31, 2010.

As of August 1, 2008, the Company had $46.0 million in available borrowing capacity under its reserve-based credit facilities and $219.0 million in outstanding debt.

Torch Arbitration Award

A hearing for the arbitration proceeding discussed in Note 11 was held before a panel of three arbitrators in Houston, Texas in June 2008. On July 18, 2008, the arbitration panel issued its final award (the "Final Award") in which the panel found and concluded, among other things, that:

- the termination of the Gas Purchase Contract did not alter or affect its incorporation by reference into the conveyances that created the NPI and Other NPIs;
- the sharing arrangement and other pricing terms of the Gas Purchase Contract continue to burden the NPI and Other NPIs and will do so for the lives of the NPI and Other NPIs; and
- specifically, the sharing arrangement and other pricing terms of the Gas Purchase Contract will continue to control the amount owed to the holder of the NPI and Other NPIs.

The arbitrators also denied each party's request for fees and costs and ordered each party to bear its own fees and costs related to the arbitration. Under the Federal Arbitration Act, which we believe governs post-hearing procedure in this proceeding, the arbitration panel's Final Award may only be modified or vacated based upon certain limited grounds specified in such Act, such as "fraud," "evident partiality," "misconduct," "evident miscalculation" or "evident material mistake". Under such Act, any effort to modify or vacate the Final Award must be filed by October 16, 2008.

Class D Interests

With the issuance of the Final Award in respect of the arbitration proceeding discussed in Note 11, it appears that amounts payable to the holder of the NPI will continue to be calculated based on the sharing arrangement and we intend, pursuant to our operating agreement, to lift the suspension of and resume making quarterly cash distributions in respect of the Class D interests beginning with the special quarterly cash distribution for the three months ending September 30, 2008. Also pursuant to our operating agreement, we intend to make a one-time special cash distribution of $666,666.66 in respect of our Class D interests for the quarterly periods ended March 31 and June 30, 2008. We expect to make this special cash distribution contemporaneously with the special quarterly cash distribution for the three months ending September 30, 2008.

Management Services Agreement

In July 2008, the conflicts committee of the Company's board of managers approved the second quarter 2008 costs for services to be charged by CEPM and its affiliates to the Company and determined that they were fair to and in the best interests of the Company. Additionally, CEPM has agreed to waive payment in cash of its third quarter 2008 fees to be billed to the Company in an amount equal to one-half of the Company's incurred fees and expenses in connection with the Torch arbitration, up to a maximum of $600,000.

CoLa Acquisition

On July 29, 2008, a post-closing adjustment occurred in connection with the CoLa acquisition to settle certain items including the revenue distributions and certain expenses associated with the acquired oil and gas properties on or after the effective date of January 1, 2008. The Company received approximately $1.7 million, which will reduce the value of the acquired natural gas properties, equipment and facilities. Additional adjustments for title, revenue distributions and certain expenses will occur through July 31, 2009.

Unit-Based Compensation

The Company granted 21,594 restricted common unit awards on August 1, 2008, to certain field employees of the Company in Alabama and Oklahoma. These units had a total fair market value of approximately $401,872 based on the average of the high and low trading price of the Company's units on NYSE Arca on the grant date. These service-based restricted units will vest on a three year ratable schedule beginning on August 1, 2009.

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

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

Overview

We are a limited liability company formed by Constellation Energy Group, Inc. ("Constellation") on February 7, 2005 to acquire oil and natural gas properties ("E&P properties") as well as related midstream assets. At June 30, 2008, our oil and natural gas reserves were located in the Black Warrior Basin of Alabama, in the Cherokee Basin of Kansas and Oklahoma, and in the Woodford Shale in Oklahoma. Our primary business objective is to generate stable cash flows allowing us to make quarterly cash distributions to our unitholders and over time to increase the amount of our future quarterly distributions. Our strategies for achieving this objective are to:

- 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;
- organically grow our business by increasing reserves and production through what we believe to be low-risk development drilling that focuses on capital efficient production growth;
- realize value by opportunistically forming partnerships, participating in farm-out arrangements, joint operating agreements or other capital-efficient ventures to take advantage of our significant undeveloped acreage positions in the Cherokee Basin; and
- reduce the volatility in our revenues resulting from changes in oil and natural gas commodity prices through efficient hedging programs.

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

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

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

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

- In March 2008, we completed an acquisition of 83 non-operated producing wells located in the Woodford Shale in Oklahoma (the “CoLa Assets” or “CoLa Acquisition”).
- In September 2007, we completed the acquisition of additional coalbed methane properties in the Cherokee Basin of Oklahoma (the “Newfield Assets” or “Newfield Acquisition”).
- In July 2007, we completed an acquisition of additional oil and natural gas properties located in the Cherokee Basin in Oklahoma (the “Amvest Acquisition”).
- In April 2007, we completed an acquisition of oil and natural gas properties located in the Cherokee Basin in Kansas and Oklahoma (the “EnergyQuest Assets” or “EnergyQuest Acquisition”).

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

Unless the context requires otherwise, any reference in this 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		For the Six Months Ended	
	June 30, 2008	June 30, 2007	June 30, 2008	June 30, 2007
	(In 000's)			
Reconciliation of Net Income to Adjusted EBITDA:				
Net income	$ (8,790)	$ 2,193	$ (6,326)	$ 4,447
Adjusted by:				
Interest expense (income), net	3,059	1,182	5,378	1,690
Depreciation, depletion and amortization	11,489	3,584	21,022	5,543
Accretion of asset retirement obligation	101	77	202	113
(Gain) loss on sale of assets	—	(1)	(211)	94
Loss on mark-to-market activities	15,033	2,619	17,989	5,401
Long-term incentive plan	57	—	155	—
Unrealized loss (gain) on natural gas derivatives	(410)	223	(159)	(174)
Adjusted EBITDA	$ 20,539	$ 9,877	$ 38,050	$ 17,114

Significant Operational Factors since December 31, 2007

- *Realized Prices.* Our average realized price for the six months ended June 30, 2008, including hedges, was $6.31 per Mcfe. This realized price includes the impact of $18.0 million of losses on mark-to-market derivatives. Excluding the impact of the mark-to-market losses, the average realized price for the six months ended June 30, 2008 was $8.43 per Mcfe. Further deducting the cost of sales associated with third party gathering, average realized prices were $8.03 including hedges and $8.82 excluding hedges.
- *Production.* Our production for the first six months of 2008 was approximately 8.5 Bcfe, or an average of 46,511 Mcfe per day.
- *Capital Expenditures and Drilling Results.* For the six months ended June 30, 2008, we incurred approximately $19.4 million in capital expenditures for development activities and $50.4 million for acquisition activities. Our development activities have been focused on completing the wells associated with our planned 2008 maintenance capital budget of $29.0 million. This maintenance capital spending is intended to maintain our production rates, reserves, and asset base. To date, our drilling program has replaced production at a rate sufficient to offset the natural decline rate from our existing properties.

  We accelerated our 2008 drilling program in the Black Warrior Basin and have drilled and completed all 15 planned net wells with a 100% drilling success rate. We have also drilled 35 net wells and performed 18 net recompletions in the Cherokee Basin. As of June 30, 2008, we had also completed drilling an additional 44 net wells and 6 recompletions in the Cherokee Basin and anticipate them flowing to sales before December 31, 2008.

  In the Cherokee Basin, we are progressing on a three rig drilling program where one rig is dedicated to drilling traditional vertical wells while the other two rigs are dedicated to drilling horizontal and directional wells. In other coalbed methane basins, horizontal drilling technology has been successfully used to increase production and to increase economic returns. As the costs for horizontal drilling have declined and techniques have improved, we believe this type of drilling technology may be suitable in the Cherokee Basin. We expect that the costs for the horizontal wells will be marginally higher than our traditional vertical wells with higher production rates and reserves recoveries. Since we have completed our 2008 drilling program in the Black Warrior Basin, we have expanded our efforts in the Cherokee Basin by concentrating on our horizontal program. Through July 2008, we have drilled and completed 6 horizontal wells in Osage County, Oklahoma. Average initial production flow rates of 88 Mcf per day for these recently drilled horizontal wells have met or exceeded the flow rates of our recently drilled traditional vertical wells. More comprehensive drilling and production results from our horizontal program will begin to be available in the third quarter 2008.
- *Operating Expenses.* Operating expenses increased from 2007, reflecting the additional properties acquired in the EnergyQuest, Amvest, Newfield, and CoLa Acquisitions. Additionally, we experienced increased costs in the Cherokee Basin in connection with weather-related maintenance and repairs following a severe winter ice storm, a fire at our Dewey, Oklahoma field office, and additional costs of integrating and reorganizing our field offices surrounding Tulsa, Oklahoma. Our new office in Tulsa opened in May 2008 and is now the center of our operations in the Cherokee Basin. We do not expect these atypical costs to continue through the second half of 2008.

  In April 2008, the conflicts committee of our board of managers agreed to the charges to be paid to CEPM for the remainder of 2008 under the management services agreement. The payments to CEPM are due quarterly and may not exceed $3.4 million for all of 2008. In the first six months of 2008, the actual fees invoiced by CEPM were $1.1 million. The charges to be invoiced during the remainder of 2008 are expected to be approximately $1.6 million, but may be adjusted to reflect additional services provided by CEPM and its affiliates or the transition of services to CEP employees.

- *Insured Loss.* In January 2008, we experienced a fire at our field office in Dewey, Oklahoma. Both the facility and certain inventory and equipment were damaged. Substantially all of the damage to the building and equipment is expected to be covered by insurance, less a $5,000 deductible. However, certain expenses as a result of the business interruption resulting from the fire are not covered by insurance. These costs, such as temporary office space and other incremental expenses incurred as a result of the fire at the field office, will be expensed as they are incurred. As of June 30, 2008, we recorded a gain of $0.2 million as the insurance proceeds of $0.4 million exceeded the net book value of the building.
- *CoLa Acquisition.* On March 31, 2008, we acquired the interests in 83 non-operated producing wells located in the Woodford Shale in Coal and Hughes counties in Oklahoma for an aggregate purchase price of approximately $53.4 million, subject to purchase price adjustments. The acquisition included an estimated 12.7 Bcfe of proved developed producing reserves with an estimated daily net production of 3.9 MMcfe at June 30, 2008. The wells have an average gross working interest of 11.5% and a net revenue interest per well of 9.2%. Approximately 90% of the wells are operated by affiliates of Devon Energy Company and Newfield Exploration Company, with the remaining wells operated by three additional companies. The average annual decline rate for the reserves associated with these wells is estimated at 7 to 8 percent over 10 years.
- *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 up to 80% of our forecasted production for up to a five year period. Our management, however, may modify the hedging percentages and strategies as it deems appropriate for market conditions, the cost associated with the derivatives and other business strategies. In April 2008, we added additional derivative positions for our expected future natural gas production. All of our current outstanding derivative positions are outlined starting on page 30.

  We entered into derivative transactions to hedge certain of the future expected production associated with each of our EnergyQuest, Amvest, Newfield, and CoLa Acquisitions. Certain of these positions were accounted for as mark-to-market activities until designated as cash flow hedges under SFAS 133. This accounting treatment can cause earnings volatility as the positions for future natural gas production are marked-to-market. These non-cash unrealized gains or losses are included in our current Statement of Operations until the derivatives are designated as cash flow hedges or are cash settled as the commodities are produced and sold. The swaps associated with the EnergyQuest, Amvest, Newfield, and CoLa Acquisitions are now being accounted for using cash flow hedge accounting. We have put options, a swaption, certain swaps associated with our anticipated production in the Cherokee Basin, and certain basis swaps that continue to be accounted for using the mark-to-market accounting method. When our derivative positions are cash settled as the related commodities are produced and sold, the realized gains and losses of those derivative positions are included in our Statement of Operations as Oil and Gas Sales.

  We experience earnings volatility as a result of using the mark-to-market accounting method for certain of our commodity derivatives used to hedge our exposure to changes in natural gas prices. We use derivatives to lock in the future sales price for a portion of our expected natural gas production. Increases in the market price of natural gas relative to the fixed future sales price for our hedges result in unrealized, non-cash mark-to-market losses on those derivatives and lower reported net income. Decreases in the market price of natural gas relative to the fixed future sales price for our hedges result in unrealized, non-cash mark-to-market gains on those derivatives and higher reported net income. Although these gains and losses are required to be reported immediately in earnings as market prices change, the fair value of the related future physical natural gas sale is not marked-to-market and therefore is not reflected as Oil and Gas Sales or as an Accounts Receivable in our financial statements. This mismatch impacts our reported Result of Operations and our reported working capital position until the commodity derivatives are cash settled and the natural gas is produced and sold. Upon cash settlement of the derivatives, the sale of the physical commodity at then-current market prices offsets the previously reported mark-to-market gains or losses such that the cumulative net cash realized results in a net sale of the physical natural gas production at the fixed future sales price for our hedge. A further detail of our commodity derivative positions and their accounting treatment are outlined starting on page 30.
- *Debt.* We entered into a new reserve-based credit facility and amended our existing credit facility during the first quarter 2008. As of July 1, 2008, the combined borrowing base under these two facilities is $265.0 million. The two agreements contain similar commercial terms with the same lenders participating in the same applicable percentages. A cross-default feature provides that an event of default under one agreement constitutes an event of default under the other. Each credit agreement is secured by distinct mortgages of properties as well as guarantees by certain of our operating subsidiaries. The credit facilities will mature in October 2010. As of August 1, 2008, we had $219.0 million in outstanding debt under our reserve-based credit facilities.

Results of Operations

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

	For the Three Months Ended				For the Six Months Ended			
	(Dollars in 000's)							
	June 30, 2008	June 30, 2007	Variance $	Variance %	June 30, 2008	June 30, 2007	Variance $	Variance %
Revenues:								
Oil and gas sales	$ 38,994	$15,190	$ 23,804	156.7%	$ 71,382	$26,497	$ 44,885	169.40%
Loss from mark-to- market activities	(15,033)	(2,619)	(12,414)	474.0%	(17,989)	(5,401)	(12,588)	233.1%
Total revenues	23,961	12,571	11,390	90.6%	53,393	21,096	32,297	153.3%
Operating expenses:								
Lease operating expenses	9,209	3,150	6,059	192.3%	18,273	4,745	13,528	285.1%
Cost of sales	2,239	—	2,239	100.0%	3,387	—	3,387	100.0%
Production taxes	2,885	685	2,200	321.2%	4,550	1,144	3,406	297.7%
General and administrative expenses	3,787	1,771	2,016	113.8%	7,122	3,390	3,732	110.1%
Gain (loss) on sale of asset	—	(1)	1	(100.0)%	(211)	94	(305)	(324.5)%
Depreciation, depletion and amortization	11,489	3,584	7,905	220.6%	21,022	5,543	15,479	279.3%
Accretion expenses	101	77	24	31.2%	202	113	89	78.8%
Total operating expenses	29,710	9,266	20,444	220.6%	54,345	15,029	39,316	261.6%
Other expenses (income):								
Interest expense	3,102	1,266	1,836	145.0%	5,662	1,825	3,837	210.2%
Interest income	(43)	(84)	41	(48.8)%	(284)	(135)	(149)	110.4%
Other (income) expense	(18)	(70)	52	(74.3)%	(4)	(70)	66	(94.3)%
Total other expenses (income)	3,041	1,112	1,929	173.5%	5,374	1,620	3,754	231.7%
Total expenses	32,751	10,378	22,373	215.6%	59,719	16,649	43,070	258.7%
Net income (loss)	$ (8,790)	$ 2,193	$(10,983)	(500.8)%	$ (6,326)	$ 4,447	$(10,773)	(242.3)%
Net production:								
Total production (MMcfe)	4,422	1,796	2,626	146.2%	8,465	3,023	5,442	180.0%
Average daily production (Mcfe/d)	48,593	19,736	28,857	146.2%	46,511	16,702	29,809	178.5%
Average sales prices:								
Price per Mcfe including hedges	$ 5.42[a]	$ 7.00 [a]	$ (1.58)	(22.6)%	$ 6.31[a]	$ 6.98[a]	$ (0.67)	(9.6)%
Price per Mcfe excluding hedges	$ 10.42	$ 7.56	$ 2.86	37.8%	$ 9.22	$ 7.32	$ 1.90	25.9%
Average unit costs per Mcfe:								
Field operating expenses[b]	$ 2.73	$ 2.13	$ 0.60	28.1%	$ 2.70	$ 1.95	$ 0.75	38.4%
Lease operating expenses	$ 2.08	$ 1.75	$ 0.33	18.7%	$ 2.16	$ 1.57	$ 0.59	37.5%
Production taxes	$ 0.65	$ 0.38	$ 0.27	71.1%	$ 0.54	$ 0.38	$ 0.16	42.0%
General and administrative expenses	$ 0.86	$ 0.99	$ (0.13)	(13.2)%	$ 0.84	$ 1.12	$ (0.28)	(25.0)%
Depreciation, depletion and amortization	$ 2.60	$ 2.00	$ 0.60	30.2%	$ 2.48	$ 1.83	$ 0.65	34.8%

(a) Includes the impact of mark-to-market losses on derivatives that do not qualify for cash flow hedging.
(b) Field operating expenses include lease operating expenses and production taxes.

Three months ended June 30, 2008 compared to the three months ended June 30, 2007

Oil and gas sales. Oil and natural gas sales increased $23.8 million, or 156.7%, to $39.0 million for the three months ended June 30, 2008 as compared to the three months ended June 30, 2007. Of this increase, $19.9 million was attributable to increased production volumes and $12.6 million was attributable to higher market prices for oil and natural gas, offset by an $8.7 million decrease attributable to our hedge program. Production for the three months ended June 30, 2008 was 4.4 Bcfe, which was higher than the three months ended June 30, 2007 as a result of the acquisition of our properties in the Cherokee Basin and the Woodford Shale and our maintenance drilling program offsetting the natural decline rate of production associated with our existing wells. The acquisition of properties in the Cherokee Basin and in the Woodford Shale contributed 2.6 Bcfe of the increase. We hedged approximately 88% of our actual production from April 2008 through June 2008 and approximately 96% of our actual production from April 2007 through June 2007.

As discussed below, the loss from our mark-to-market activities increased $12.4 million for the three months ended June 30, 2008, as compared to the three months ended June 30, 2007. Our realized prices before our hedging program increased from 2007 to 2008 primarily due to higher market prices for oil and natural gas. This was offset by our hedging program and the mark-to-market loss discussed below.

Hedging and mark-to-market activities. In conjunction with the EnergyQuest, Amvest, Newfield, and CoLa Acquisitions, we entered into derivative transactions to hedge a portion of the future expected production associated with these acquisitions before they 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, August 20, 2007, for Amvest, January 31, 2008, for Newfield and March 31, 2008, for CoLa, at which time a majority of the derivatives were designated as cash flow hedges and began receiving cash flow accounting treatment. Our put options, a swaption, certain basis swap transactions, and certain additional derivatives entered into in April 2008 are accounted for as mark-to-market activities. For the quarter ended June 30, 2008, the mark-to-market loss was approximately $15.0 million. This non-cash loss represents the impact of higher expected future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities.

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 June 30, 2008, we recognized a gain of approximately $0.4 million related to hedge ineffectiveness primarily related to our hedges of production in the Cherokee Basin. For the three months ended June 30, 2007, we recognized a loss of approximately $0.2 million related to hedge ineffectiveness.

Cash hedge settlements paid for our commodity derivatives were $7.4 million for the three months ended June 30, 2008. Cash hedge settlements received for our commodity derivatives were $1.8 million for the three months ended June 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 June 30, 2008, lease operating expenses increased $6.0 million, or 192.3%, to $9.2 million, compared to expenses of $3.2 million for the three months ended June 30, 2007. This increase was primarily the result of the costs of operating the properties acquired in our Amvest, Newfield, and CoLa Acquisitions. Our lease operating expenses were higher in the three months ended June 30, 2008, as compared to the three months ended June 30, 2007, because of an additional $1.4 million in compression, treating, and transportation charges, $1.3 million in well servicing costs, $1.1 million in labor and benefits, $1.0 million in repairs and maintenance, and $0.4 million in power and fuel charges. We also incurred an additional $0.1 million in expenses related to the Dewey office fire.

For the three months ended June 30, 2008, our per unit lease operating expenses were $2.08 per Mcfe, as compared to $1.75 per Mcfe for the three months ended June 30, 2007. This rate decreased from $2.24 per Mcfe for the three months ended March 31, 2008, as a result of fewer weather-related costs and a focus on controlling costs.

For the three months ended June 30, 2008, production taxes increased $2.2 million, or 321.2%, to $2.9 million, compared to production taxes of $0.7 million for the three months ended June 30, 2007. This increase was primarily the result of the additional taxes resulting from oil and gas production in Oklahoma and Kansas as a result of the EnergyQuest, Amvest, and Newfield Acquisitions and the impact of significantly higher market prices for oil and natural gas on value-based severance taxes. Our newly acquired properties in the Woodford Shale are eligible for a reduced tax rate of 1% instead of 7% for a period of 24 months after the first date of production. A majority of our 83 wells in the Woodford Shale are currently being certified for the tax credit.

Cost of sales was $2.2 million for the three months ended June 30, 2008 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.

General and administrative expenses increased $2.0 million, or 113.8%, to $3.8 million for the three months ended June 30, 2008, as compared to the three months ended June 30, 2007. This increase was primarily due to our acquisitions in the Cherokee Basin increasing our administrative overhead burdens. Our general and administrative expenses were higher in the three months ended June 30, 2008, as compared to the three months ended June 30, 2007, because of an additional $0.6 million in administrative costs in Tulsa, $0.5 million in legal fees primarily associated with the Torch arbitration, $0.4 million in costs associated with providing outsourced accounting services for our properties in the Cherokee Basin, $0.3 million in CEPM charges for labor, and $0.2 million in non-cash expenses associated with restricted unit grants under our long-term incentive program. In the second quarter of 2008 and 2007, CEPM allocated $0.7 million and $0.4 million, respectively, in expenses to us for labor and other charges.

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

Our depreciation, depletion and amortization expense for the three months ended June 30, 2008 was $11.5 million, or $2.60 per Mcfe, compared to $3.6 million, or $2.00 per Mcfe, for the three months ended June 30, 2007. This increase reflects the increased basis in our assets resulting from the cost of our asset acquisitions in the Cherokee Basin and in the Woodford Shale, additional capital expenditures for our development drilling programs, and a 2.6 Bcfe increase in production volumes for the three months ended June 30, 2008 as compared to the three months ended June 30, 2007.

Interest expense. Interest expense for the three months ended June 30, 2008 increased $1.8 million to $3.1 million as compared to approximately $1.3 million in interest expense for the three months ended June 30, 2007. This increase was due to the borrowings under our reserve-based credit facilities to finance the acquisitions of our Cherokee Basin and Woodford Shale properties, investment capital expenditures and working capital borrowings done in the third quarter 2008. At June 30, 2008, we had an outstanding balance under our credit facilities of $216.0 million as compared to $82.5 million at June 30, 2007.

Interest income. Interest income was less than $0.1 million for the three months ended June 30, 2008 and less than $0.1 million for the three months ended June 30, 2007. During the three months ended June 30, 2008 and 2007, we earned interest income by utilizing overnight investments on our excess cash balances.

Accumulated other comprehensive income. Accumulated other comprehensive income, shown on our consolidated balance sheets, reflects the changes in the fair market value of our open hedge positions. At June 30, 2008, the balance was an unrealized loss of $138.8 million compared to an unrealized gain of $4.2 million at December 31, 2007. This decrease reflects the significant increase in the expected future market prices for natural gas in conjunction with an increase in the amount of future expected production to be hedged as a result of our acquisitions.

The change in Accumulated other comprehensive income (loss) is shown in our consolidated statements of operations and comprehensive income (loss) as an unrealized loss of $94.8 million for the three months ended June 30, 2008, and an unrealized gain of $6.2 million for the three months ended June 30, 2007. This change is primarily due to the impact of the increase in expected future market prices for natural gas on our outstanding commodity derivatives accounted for as cash flow hedges. Notwithstanding these unrealized losses, as these positions cash settle in the future, we expect to realize an offsetting gain upon the sale of natural gas production for which these hedges have fixed the future sales price.

We classify our open hedge positions as Level 2 or Level 3 under SFAS 157. Certain of our derivatives are classified as Level 3 because observable market data is not available for all of the time periods for which we have derivative instruments. As observable market data becomes available for all of the time periods, these derivative positions will be reclassified as Level 2. The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value of our derivatives. The market price for natural gas is the primary driver for the determination of the fair value of our derivatives. Before the cash settlement of our derivatives, increases and decreases in the fair value of our derivatives have no impact on our liquidity, capital resources, and cash flows because all our derivative positions are secured by our reserve-based credit facilities or done with guarantees with Constellation such that we do not post collateral with our counterparties. Our derivative instruments are settled in cash according the terms of the derivative agreements at the time the commodity being hedged is produced and sold. We do not enter into speculative trading positions.

Six months ended June 30, 2008 compared to the six months ended June 30, 2007

Oil and gas sales. Oil and natural gas sales increased $44.9 million, or 169.4%, to $71.4 million for the six months ended June 30, 2008 as compared to the six months ended June 30, 2007. Of this increase, $39.8 million was attributable to increased production volumes and $16.1 million was attributable to higher market prices for oil and natural gas, offset by a $11.0 million decrease attributable to our hedge program. Production for the six months ended June 30, 2008 was 8.5 Bcfe, which was higher than the six months ended June 30, 2007 as a result of the acquisition of our properties in the Cherokee Basin and in the Woodford Shale, our maintenance drilling program offsetting the natural decline rate of production associated with our existing wells, and other operational improvements including increased use of compression. The acquisition of properties in the Cherokee Basin and in the Woodford Shale contributed 5.4 Bcfe of the increase. We hedged approximately 92% of our actual production from January 2008 through June 2008 and approximately 90% of our actual production from January 2007 through June 2007.

As discussed below, the loss from our mark-to-market activities increased $12.6 million for the six months ended June 30, 2008, as compared to the six months ended June 30, 2007. Our realized prices before our hedging program increased from 2007 to 2008 primarily due to higher market prices for oil and natural gas. This was offset by our hedging program and the mark-to-market loss discussed below.

Hedging and mark-to-market activities. In conjunction with the EnergyQuest, Amvest, Newfield, and CoLa Acquisitions, we entered into derivative transactions to hedge a portion of the future expected production associated with these acquisitions before they closed. These derivatives were accounted for as mark-to-market activities and were recorded at fair value in our financial statements until June 18, 2007, for EnergyQuest, August 20, 2007, for Amvest, January 31, 2008, for Newfield and March 31, 2008, for CoLa, at which time a majority of the derivatives were designated as cash flow hedges and began receiving cash flow accounting treatment. Our put options, a swaption, certain basis swap transactions, and certain additional derivatives entered into in April 2008 are accounted for as mark-to-market derivatives. For the six months ended June 30, 2008, the mark-to-market loss was approximately $18.0 million. This non-cash loss represents the impact of higher expected future natural gas prices on these derivative transactions that were being accounted for as mark-to-market activities.

We have entered into cash flow hedges in an effort to reduce our exposure to short-term fluctuations in natural gas prices. For both the six months ended June 30, 2008, and June 30, 2007 we recognized a gain of approximately $0.2 million related to hedge ineffectiveness primarily related to our hedges of production in the Cherokee Basin.

Cash hedge settlements paid for our commodity derivatives were $6.5 million for the six months ended June 30, 2008. Cash hedge settlements received for our commodity derivatives were $4.1 million for the six months ended June 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.

For the six months ended June 30, 2008, lease operating expenses increased $13.5 million, or 285.1%, to $18.2 million, compared to expenses of $4.7 million for the six months ended June 30, 2007. This increase was the result of the costs of operating the properties acquired in the EnergyQuest, Amvest, Newfield, and CoLa Acquisitions. Our lease operating expenses were higher in the three months ended June 30, 2008, as compared to the three months ended June 30, 2007, because of an increase of $3.2 million in compression, treating, and transportation charges, $2.9 million in labor and benefits, $1.7 million in well servicing costs, $1.6 million in repairs and maintenance, $0.9 million in insurance expenses, $0.8 million in field reorganization expenses in Tulsa, $0.8 million in power and fuel charges, and $0.2 million in incremental expenses associated with the Dewey office fire.

For the six months ended June 30, 2008, per unit lease operating expenses were $2.16 per Mcfe compared to $1.57 per Mcfe for the six months ended June 30, 2007. Certain weather-related and specific field office events described below, which are not expected to be ongoing, contributed to the per unit increase in operating expenses experienced in the Cherokee Basin compared to 2007. During the six months ended June 30, 2008, our lease operating expenses in the Cherokee Basin were impacted by $0.5 million in repair costs to restore production after a significant winter ice storm in Oklahoma, $0.8 million of field reorganization expenses in Tulsa, $0.3 million in costs associated with the final Newfield settlement under the transition services agreement, and $0.1 million in incremental expenses associated with the Dewey office fire, surface damages, shut-in payments, and environmental costs. Our per unit lease operating expenses decreased to $2.08 per Mcfe during the three months ended June 30, 2008, which brought our per unit lease operating expenses for the six months ended down to $2.16 per Mcfe. We expect our lease operating expenses to be approximately $1.90 to $2.10 per Mcfe for the remainder of 2008.

For the six months ended June 30, 2008, production taxes increased $3.4 million, or 297.7%, to $4.5 million, compared to expenses of $1.1 million for the six months ended June 30, 2007. This increase was primarily the result of the additional taxes resulting from oil and gas production in Oklahoma and Kansas as a result of the EnergyQuest, Amvest, Newfield, and CoLa Acquisitions and higher market prices for oil and natural gas.

Cost of sales was $3.4 million for the six months ended June 30, 2008 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.

General and administrative expenses increased $3.7 million, or 110.1%, to $7.1 million for the six months ended June 30, 2008, as compared to $3.4 million for the six months ended June 30, 2007. This increase was primarily due to our acquisitions in the Cherokee Basin increasing our administrative overhead burdens. Our general and administrative expenses were higher in the six months ended June 30, 2008, as compared to the six months ended June 30, 2007, because of an additional $1.2 million in administrative costs in Tulsa, $0.8 million in professional services costs primarily associated with providing outsourced accounting services for our properties in the Cherokee Basin, $0.7 million in legal fees primarily associated with the Torch arbitration, $0.3 million in CEPM charges for labor, $0.2 million in audit and tax fees, $0.2 million in non-cash expenses associated with restricted unit grants under our long-term incentive program, and $0.1 million in credit support fees to Constellation. For the six months ended June 30, 2008 and 2007, CEPM allocated $1.1 million and $0.4 million, respectively, in expenses to us for labor and other charges.

Our per unit costs were $0.84 per Mcfe for the six months ended June 30, 2008 compared to $1.12 per Mcfe for the six months ended June 30, 2007. This decrease is attributable to increased production volumes as a result of our acquisitions in the Cherokee Basin and the Woodford Shale, as well as the economies of scale associated with spreading fixed administrative expenses over a larger base of properties.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs.

Our depreciation, depletion and amortization expense for the six months ended June 30, 2008 was $21.0 million, or $2.48 per Mcfe, compared to $5.5 million, or $1.83 per Mcfe, for the six months ended June 30, 2007. This increase reflects the increased basis in our assets resulting from the cost of our asset acquisitions in the Cherokee Basin and in the Woodford Shale, additional capital expenditures for our development drilling programs, and a 5.4 Bcfe increase in production volumes for the six months ended June 30, 2008 as compared to the six months ended June 30, 2007. Our depletion rate for the Woodford Shale properties is approximately $4.00 per Mcfe, which increases our average per unit depletion rate.

Interest expense. Interest expense for the six months ended June 30, 2008 increased $3.8 million to $5.6 million as compared to approximately $1.8 million in interest expense for the six months ended June 30, 2007. This increase was due to increased borrowings under our reserve-based credit facilities to finance the acquisitions of our Cherokee Basin and Woodford Shale properties, investment capital expenditures and the accelerated amortization of $0.1 million in debt issue costs as a result of amending our credit facility. At June 30, 2008, we had an outstanding balance under our credit facilities of $216.0 million as compared to $82.5 million at June 30, 2007.

Interest income. Interest income was $0.2 million for the six months ended June 30, 2008 and $0.1 million for the six months ended June 30, 2007. During the six months ended June 30, 2008 and 2007, we earned interest income by utilizing overnight investments on our excess cash balances. In March 2008, we received $0.1 million in interest on payment balances from receivables related to the sales of natural gas included in the Torch NPI escrow account. Effective with the termination of the Trust, the escrow account arrangement has also terminated and all payments for natural gas sales will be directly received by us.

Accumulated other comprehensive income. The change in Accumulated other comprehensive income (loss) is shown in our consolidated statements of operations and comprehensive income (loss) as an unrealized loss of $143.0 million for the six months ended June 30, 2008, and as an unrealized loss of $3.6 million for the six months ended June 30, 2007. This change is primarily due to the impact of the increase in expected future market prices for natural gas on our outstanding commodity derivatives accounted for as cash flow hedges. Notwithstanding these unrealized losses, as these positions cash settle in the future, we expect to realize an offsetting gain upon the sale of natural gas production for which these hedges have fixed the future sales price.

Liquidity and Capital Resources

During the six months ended June 30, 2008, we utilized proceeds from borrowings under our credit facilities and cash flow from operations as our primary sources of capital. As of June 30, 2008, 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 in the Woodford Shale. 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 and managing the costs associated with our operations. Based upon our current expectations and the existing market prices for oil and natural gas, we expect to continue to generate cash flow sufficient to support our projected maintenance capital expenditures and operations of our business. However, we will not fully benefit from higher market prices for natural gas because of our hedging program, which is further discussed on page 30.

Our reserve-based credit facilities may also be used to help finance future expansion capital expenditures, such as drilling and recompletions beyond that required to maintain production, as well as additional acquisitions. As of June 30, 2008, our borrowing base on our reserve-based credit facilities was $240.0 million. At June 30, 2008, we had $216.0 million of debt outstanding under the reserve-based credit facilities and $24.0 million in unused borrowing capacity. In July 2008, we expanded our borrowing base to $265.0 million by including our Woodford Shale properties under the new credit facility, which increased unused borrowing capacity to $49.0 million. In the first quarter of 2008, we filed a shelf registration statement with the SEC to register up to $1.0 billion of debt or equity securities to fund future expansion capital expenditures. This registration statement is now effective. There is no guarantee that securities can or will be issued under the registration statement. Additionally, our credit facilities allow us the ability to issue up to $300 million of unsecured debt, which would have the effect of reducing the borrowing base under our reserve-based credit facilities by 30 cents for every dollar of unsecured debt issued.

In each of the next two years, we expect to utilize our cash flow from operations and borrowings under our reserve-based credit facilities to fund a significant portion of our drilling expenditures. We expect to fund our remaining 2008 and 2009 maintenance capital expenditures and other working capital needs with cash flow from operations supplemented by borrowings under our credit facilities. We expect to fund all of our 2008 and 2009 investment capital expenditures and any additional expansion capital expenditures that we might incur with borrowings under our reserve-based credit facilities and issuances of additional units subject to market conditions. We estimate that we will have sufficient cash flow from operations after funding 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. Based on our distribution level, beginning in the fourth quarter 2007, we commenced the management incentive interest vesting period under our operating agreement. 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. A cash reserve has been established to fund future distributions on the management incentive interests. After the August 15, 2008 distribution, the reserve will be increased from $0.3 million to $0.5 million.

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

Reserve-Based Credit Facilities

On March 28, 2008, we entered into a new $500.0 million secured credit facility with The Royal Bank of Scotland as administrative agent and a syndicate of lenders. The amount available for borrowing at any one time under the Credit Facility is limited to the borrowing base for our properties other than in the State of Alabama, which was initially set at $150.0 million. As of June 30, 2008, we have borrowed $135.0 million under the facility and have a remaining capacity of $15.0 million under the Credit Facility. On July 1, 2008, we expanded our borrowing base under this facility to $175.0 million, which had the effect of increasing remaining capacity under the Credit Facility to $40.0 million. On March 28, 2008, we also amended and restated our existing $200.0 million credit facility by entering into an amended and restated credit agreement with The Royal Bank of Scotland as administrative agent and a syndicate of lenders. The amount available for borrowing at any one time under the Amended and Restated Credit Facility is limited to the borrowing base for our properties in the State of Alabama, which was initially set at $90.0 million. As of June 30, 2008, we have borrowed $81.0 million and have a remaining capacity of $9.0 million under the Amended and Restated Credit Facility. Both of our credit facilities will mature on October 31, 2010. As of August 1, 2008, we had $219.0 million in debt outstanding under these credit facilities. The amount available for borrowing at any one time is limited to the borrowing base. The borrowing base will be re-determined semi-annually, and may be re-determined at our request more frequently and by the lenders in their sole discretion based on reserve reports prepared by reserve engineers, together with, among other things, the 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 two agreements contain similar commercial terms with the same lenders participating in the same applicable percentages. A cross-default feature provides that an event of default under one agreement constitutes an event of default under the other. Our obligations under our credit facilities are secured by mortgages on our natural gas properties, as well as a pledge of all ownership interests in our subsidiaries. We are required to maintain the mortgages on properties representing at least 85% of our proved producing and proved non-producing reserves. Additionally, the obligations under the credit facilities are guaranteed by all of our operating subsidiaries and any future material subsidiaries.

Borrowings under our credit facilities are available to us for acquisition, exploration, operation and maintenance of 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.

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

- incur indebtedness;
- grant certain liens;
- make certain loans, acquisitions, capital expenditures and investments;
- make distributions other than from available cash;
- merge or consolidate; or

- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

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

- debt to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets, (gain) loss on sale of assets, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on natural gas derivatives and realized (gain) loss on cancelled natural gas derivatives, and other similar charges) of not more than 3.5 to 1.0; and
- Adjusted EBITDA to cash interest expense of not less than 2.5 to 1.0; and
- consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities, of not less than 1.0 to 1.0, all calculated pursuant to the requirements under Statement of Financial Accounting Standards (“SFAS”) 133 and SFAS 143 (including the current liabilities in respect of the termination of natural gas and interest rate swaps).

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

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

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

- failure to pay any principal when due or any interest, fees or other amount within certain grace periods;
- a representation or warranty made under the loan documents or in any report or other instrument furnished there under is incorrect when made; and
- failure to perform or otherwise comply with the covenants in the credit facility or other loan documents, subject, in certain instances, to certain grace periods, which include covenants that:
- Constellation and its affiliates maintain the right to elect our Class A Managers; and
- we obtain the approval of the administrative agent (such approval not to be unreasonably withheld or delayed) of any management services plan upon the termination of the management services agreement with CEPM;
- any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or our subsidiaries;
- the entry of, and failure to pay, one or more adverse judgments in excess of $1.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal;
- specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $1.0 million in any year; and
- a change of control, generally defined as the first date on which the following two conditions occur: (i) a decrease by CEPH and CEPM of their combined ownership of our outstanding membership interests to less than 20%, and (ii) the ownership by any person (other than a wholly-owned subsidiary of Constellation) of more than 35% of our outstanding membership interests.

At June 30, 2008, we believe that we are in compliance with the debt covenants contained in our credit facilities.

We enter into hedging arrangements to reduce the impact of changes in the LIBOR interest rate on our interest payments for our reserve-based credit facility. Currently, we have outstanding interest rate swaps that fix the LIBOR rate at 4.74%, 4.964%, 4.805%, 4.58%, and 4.56% on $16.5 million, $45.0 million, $29.5 million, $11.0 million, and $7.5 million, respectively, of our outstanding debt through February 20, 2010, September 20, 2010, October 19, 2010, August 20, 2010, and October 22, 2010, respectively.

Cash Flow from Operations

Our net cash flow provided by operating activities for the six months ended June 30, 2008 was $32.3 million, compared to net cash flow provided by operating activities of $15.8 million for the same period in 2007. This increase in operating cash flow was primarily attributable to higher sales of oil and natural gas as a result of our acquisitions in the Cherokee Basin and the impact of higher market prices for natural gas on our unhedged production volumes. For the six months ended June 30, 2008, our operating cash flows were reduced by $6.9 million related to cash hedge settlements for our natural gas commodity and interest rate derivatives. Our change in working capital was level for the six months ended June 30, 2008, as higher accounts receivables of $6.5 million were partially offset by higher royalties payable of $3.7 million and higher accrued liabilities of $2.3 million. Our receivables balances increased due to higher sales of oil and natural gas volumes and higher market prices for the related commodities. The royalties payable, which represents the amount of monies owed to the royalty owners in our properties for the monthly oil and natural gas sales, increased due to higher market prices for oil and natural gas. The decrease in affiliate payables of $1.9 million primarily resulted from the timing of the payment for 2007 expenses accrued under the management services agreement with CEPM. This impact was partially offset by a $1.1 million increase in accounts payable to third parties. This increase resulted from our increased operating and capital activities in the Cherokee Basin. We begin receiving partial cash flows from the CoLa Acquisition in the second quarter of 2008.

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

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

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

The following tables summarize, for the periods indicated, our hedges currently in place through December 31, 2013. Currently, we use fixed-price swaps and put options as our mechanisms for hedging commodity prices. All derivatives settle based on NYMEX Henry Hub prices unless otherwise noted. Our basis swaps hedge the basis differentials associated with natural gas production in the Cherokee Basin.

Our derivative positions accounted for as cash flow hedges at June 30, 2008 were:

Fixed Price Swaps

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2008	—	$ —	—	$ —	3,405,001	$ 8.42	3,405,001	$ 8.42	6,810,002	$ 8.42
2009	2,662,500	$ 8.29	2,676,250	$ 8.29	2,690,000	$ 8.29	2,690,000	$ 8.29	10,718,750	$ 8.29
2010	2,340,000	$ 8.06	2,360,000	$ 8.06	2,380,000	$ 8.06	2,380,000	$ 8.06	9,460,000	$ 8.06
2011	1,800,000	$ 8.37	1,820,000	$ 8.37	1,840,000	$ 8.37	1,840,000	$ 8.37	7,300,000	$ 8.37
2012	1,592,500	$ 8.32	1,592,500	$ 8.32	1,610,000	$ 8.32	1,610,000	$ 8.32	6,405,000	$ 8.32
									40,693,752	

Basis Swaps

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
2008	—	$ —	—	$ —	1,849,000	$ 1.00	1,753,000	$ 1.00	3,602,000	$ 1.00
2009	1,462,500	$ 1.00	1,473,750	$ 1.00	1,297,750	$ 1.00	1,201,000	$ 1.00	5,435,000	$ 1.00
2010	1,287,000	$ 1.00	1,292,000	$ 1.00	1,099,000	$ 1.00	1,000,000	$ 1.00	4,678,000	$ 1.00
									13,715,000	

Our derivative positions accounted for as mark-to-market derivatives at June 30, 2008 were:

Put Options

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2008	—	$ —	—	$ —	120,000	$ 7.78	120,000	$ 8.48	240,000	$ 8.13
2009	120,000	$ 8.83	120,000	$ 7.50	120,000	$ 7.50	40,000	$ 7.50	400,000	$ 7.90
									640,000	

Basis Swaps

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
2009	150,000	$ 1.00	150,000	$ 1.00	150,000	$ 1.00	150,000	$ 1.00	600,000	$ 1.00
2010	60,000	$ 1.00	60,000	$ 1.00	60,000	$ 1.00	60,000	$ 1.00	240,000	$ 1.00
									840,000	

Swaption

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

In February 2008, we entered into natural gas swaps in connection with the CoLa Acquisition. These derivative positions were accounted for as mark-to-market activities until the final closing of the acquisition at which time they were designated as cash flow hedges. These derivatives are primarily settled on CenterPoint Energy Gas Transmission (East) Inside FERC. We have not executed any basis swaps associated with these positions.

The positions are as follows:

Fixed Price Swaps

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2008	—	$ —	—	$ —	360,000	$ 8.29	360,000	$ 8.29	720,000	$ 8.29
2009	225,000	$ 8.11	227,500	$ 8.11	230,000	$ 8.11	230,000	$ 8.11	912,500	$ 8.11
2010	180,000	$ 7.91	180,000	$ 7.91	180,000	$ 7.91	180,000	$ 7.91	720,000	$ 7.91
2011	180,000	$ 7.93	180,000	$ 7.93	180,000	$ 7.93	180,000	$ 7.93	720,000	$ 7.93
									3,072,500	

In April 2008, the company entered into derivative positions hedges with BNP Paribas, The Royal Bank of Scotland and Societe General for the purpose of reducing the impact of lower natural gas pricing on our operations and cash flows. The derivatives are settled on a combination of NYMEX and Inside FERC prices for CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), Panhandle Eastern Pipeline (Texas, Oklahoma), and Southern Star Central Gas Pipeline (Texas, Oklahoma, and Kansas). The derivatives are connected to future production for the years 2008 through 2013 and are accounted for as mark-to-market activities.

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The positions are as follows:

Fixed Price Cash Flow Swaps

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2008	—	$ —	—	$ —	230,000	$ 10.40	230,000	$ 10.40	460,000	$ 10.40
2009	450,000	$ 9.68	455,000	$ 9.68	460,000	$ 9.68	460,000	$ 9.68	1,825,000	$ 9.68
									2,285,000	

Fixed Price Basis Swaps

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2008	—	$ —	—	$ —	230,000	$ 1.42	230,000	$ 1.42	460,000	$ 1.42
2009	450,000	$ 1.09	455,000	$ 1.09	460,000	$ 1.09	460,000	$ 1.09	1,825,000	$ 1.09
									2,285,000	

MTM Cash Flow Swaps

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2008	—	$ —	—	$ —	(35,000)	$ 14.26	(220,000)	$ 11.99	(255,000)	$ 12.30
2009	205,000	$ 11.77	70,000	$ 10.76	(60,000)	$ 10.40	(190,000)	$ 10.40	25,000	$ 22.64
2010	610,000	$ 9.28	515,000	$ 9.01	290,000	$ 8.69	320,000	$ 8.80	1,735,000	$ 9.02
2011	600,000	$ 9.12	605,000	$ 9.12	380,000	$ 8.88	380,000	$ 8.88	1,965,000	$ 9.03
2012	635,000	$ 8.38	635,000	$ 8.38	640,000	$ 8.38	640,000	$ 8.38	2,550,000	$ 8.38
2013	450,000	$ 9.16	455,000	$ 9.16	460,000	$ 9.16	460,000	$ 9.16	1,825,000	$ 9.16
									7,845,000	

MTM Basis Swaps

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2008	—	$ —	—	$ —	230,000	$ 1.31	230,000	$ 1.31	460,000	$ 1.31
2009	225,000	$ 0.89	227,500	$ 0.89	230,000	$ 0.89	230,000	$ 0.89	912,500	$ 0.89
									1,372,500	

Investing Activities—Acquisitions and Capital Expenditures

Cash used in investing activities was $69.1 million for the six months ended June 30, 2008, compared to $125.6 million for the six months ended June 30, 2007. Our capital expenditures were $69.8 million for the six months ended June 30, 2008, which primarily related to $19.4 million for drilling and development of oil and natural gas properties and $52.4 million for the CoLa Acquisition offset by $2.0 million in post-closing adjustments related to our 2007 acquisitions in the Cherokee Basin. These post-closing adjustments were primarily related to the receipt of revenues between the effective date of the transaction and the closing date and the receipt of $0.8 million in funds related to the Amvest Acquisition. We received another $0.3 million in funds related to the Amvest Acquisition in July 2008. Through the second quarter of 2008, we drilled and completed 15 net wells in the Black Warrior Basin and 35 net wells and 18 net recompletions in the Cherokee Basin. For the six months ended June 30, 2007, we drilled and completed 20 net wells in Black Warrior Basin and we completed the EnergyQuest Acquisition for $114.9 million, which is net of cash acquired.

We currently anticipate our total capital budget will be $44.5 million for the twelve months ending December 31, 2008, excluding the impact of additional acquisitions. This capital budget, of which we have spent $19.4 million as of June 30, 2008, primarily consists of capital for drilling, also includes amounts for infrastructure projects, equipment, and inventory. We expect to spend this entire budget in the Black Warrior Basin and the Cherokee Basin. As the recent acquisition in the Woodford Shale was for proved developed producing reserves, no material capital expenditures are planned on the wells. As allowed under our limited liability company agreement, maintenance capital associated with production in the Woodford Shale can be and will be redeployed to the Cherokee Basin. 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 or drilling costs escalate, we could choose to defer a portion of these planned capital expenditures until later periods. We routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and crews. Based upon current natural gas price expectations and expected production levels, we anticipate that our cash flow from operations and available borrowing capacity under our reserve-based credit facilities will meet our planned capital expenditures and other cash requirements for the twelve months ending December 31, 2008. However, future cash flows are subject to a number of variables, including the level of natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures. Our capital expenditures are also impacted by drilling and service costs. In the event of inflation increasing drilling and service costs, our hedging program will limit our ability to have increased revenues recoup the higher costs, which could impact our planned capital spending.

Financing Activities

Our net cash provided by financing activities was $35.8 million for the six months ended June 30, 2008, compared to $109.9 million provided by financing activities for the six months ended June 30, 2007. In 2008, we borrowed $63.0 million to fund the CoLa Acquisition, to fund debt issue costs, to finance capital expenditures, and for working capital needs. These net new borrowings occurred under our new reserve-based credit facility secured by our properties outside of Alabama and our amended and restated credit facility secured by properties in Alabama. These two credit facilities are not only secured by our oil and gas properties but also by our operating subsidiaries. We also paid distributions of $25.5 million to our common and Class A unitholders and on the Class D interests in 2008 and incurred $0.3 million in costs associated with our shelf registration statement.

For the six months ended June 30, 2007, we borrowed $60.5 million from our reserve-based credit facility in order to fund the EnergyQuest Acquisition. We also paid distributions of $9.0 million to our common and Class A unitholders and on the Class D interests in 2007.

Contractual Obligations

At June 30, 2008, we had the following contractual obligations or commercial commitments:

	Payments Due By Year(1)(2)						
	2008	2009	2010	2011	2012	Thereafter	Total
				(In 000's)			
Management Services Agreement (3)	$3,378	$—	$ —	$—	$—	$ —	$ 3,378
Reserve-Based Credit Facilities	—	—	216,000	—	—	—	216,000
Support Services Agreement	642	—	—	—	—	—	642
Purchase Obligation	733	—	—	—	—	—	733
Total	$4,753	$—	$216,000	$—	$—	$ —	$220,753

(1) This table does not include any liability associated with derivatives.
(2) This table does not include interest as interest rates are variable.
(3) Represents the maximum annual amount approved by the conflicts committee of our board of managers in April 2008.

At June 30, 2008, our asset retirement obligation was approximately $6.5 million.

Off-Balance Sheet Arrangements

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

Credit Markets and Counterparty Risk

Bear Energy LP

Bear Energy LP, a wholly-owned subsidiary of JP Morgan Chase, purchases the majority of our natural gas production in Alabama. We have received a guarantee from JP Morgan Chase for the obligations of Bear Energy LP. As of June 30, 2008, we have no past due receivables from Bear Energy LP.

CCG

Constellation Energy Commodities Group, Inc. purchases a portion of our natural gas production in Oklahoma and Kansas. Through July 31, 2009, we have an unconditional guarantee from Constellation for payment of up to $8 million for sales made to CCG.

SemGroup LP

In July 2008, SemGroup L.P. announced that the Company and certain of its North American subsidiaries have filed voluntary petitions for reorganization today under Chapter 11 of the U.S. Bankruptcy Code as well as an application for creditor protection under the Companies' Creditors Arrangement Act in Canada. We have no credit exposure to SemGroup LP or its subsidiaries.

Derivative Counterparties

All of our derivatives are with BNP Paribas, The Royal Bank of Scotland, and Societe Generale. These banks are lenders who participate in our reserve-based credit facilities. All of our derivatives are collateralized by our reserve-based credit facilities or are guaranteed by Constellation. As of June 30, 2008, each of these financial institutions has an investment grade credit rating.

Outlook

During the remainder of 2008, 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.

Production, Drilling, and Capital Expenditures

In 2008, we expect our net production to be at or slightly below the bottom end of our previously disclosed range of 17 Bcfe and 20 Bcfe. This is based on the progress towards completing our 2008 drilling program for newly drilled wells and recompletions. Excluding the impact of additional acquisitions, we expect to spend a total of approximately $44.5 million in capital expenditures in 2008. Of this $44.5 million, $29.0 million is estimated to be maintenance capital expenditures to maintain our production, reserves, and asset base and $15.5 million is estimated to be investment capital expenditures to support moderate organic growth. Our total 2008 program contains between 200 to 230 newly drilled wells and recompletions. We expect our 2008 drilling program to be completed at or slightly below our initial plans of drilling between 115 and 130 wells and performing 85 to 100 recompletions. Our 2008 program in the Black Warrior Basin consisted of 15 newly drilled wells and was completed as of April 30, 2008. We are evaluating the potential to redeploy some of our planned capital expenditures from the Cherokee Basin to drill up to 5 additional wells in the Black Warrior Basin. The remainder of our 2008 spending is expected to be concentrated in the Cherokee Basin. We plan to spend the $0.3 million that has been accrued for environmental liabilities during the remainder of 2008.

Natural Gas Prices and Hedging Activities

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 30. All of our derivative positions, except our puts, swaption, and certain swaps, are treated as cash flow hedges for accounting purposes. The puts, swaption, and certain swap 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, Production Taxes and General and Administrative Expenses

Our operating expenses include such items as lease operating expenses (labor, vehicle expenses, supervision, transportation, minor maintenance, ad valorem taxes, tools and supplies), production taxes and general and administrative expenses. Due to the current environment of historically high commodity prices, we anticipate that during 2008, service and labor costs, as well as costs of equipment and raw materials, will exceed the levels we experienced in 2007. We currently expect our operating expenses for 2008 to be between $54.5 million and $57.5 million. This amount does not include any expenses associated with cost of sales for gas purchases and gathering charges, which are generally offset by third-party oil and gas revenues. 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 2008, and that we do not reimburse CEPM under the management services agreement for any acquisition services.

Adjusted EBITDA

For 2008, we expect our Adjusted EBITDA to be at or slightly below the bottom end of our previously disclosed range of $94.0 million and $105.0 million.

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. Our realized sales prices for natural gas have helped to 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 and to maintain or increase our production levels over time. Our growth also depends on the ability to complete additional acquisitions which is dependent upon access to attractive debt and equity financing. In 2008, our operating and financial performance will be impacted by the success and costs of our drilling program in replacing reserves and managing the natural decline rates of our existing production.

Critical Accounting Policies and Estimates

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

As of June 30, 2008, 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, 2007. The policies disclosed included the accounting for natural gas properties, natural gas reserve quantities, net profits interest, revenue recognition and hedging activities. Please read Note 1 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

New Accounting Pronouncements

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

In March 2008, the Emerging Issues Task Force reached a consensus on Issue No. 07-4, or EITF 07-4, *Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships*. EITF 07-4 provides guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. This Issue is effective for fiscal years beginning after December 15, 2008 (January 1, 2009 for us), and interim periods within those fiscal years. Earlier application is not permitted, and the guidance in this Issue is to be applied retrospectively for all financial statements presented. CEP is currently evaluating the impact of this Issue 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 Inside FERC prices for Southern Natural Gas Company (Louisiana) with respect to our properties in the Black Warrior Basin and CenterPoint Energy Gas Transmission (East), Natural Gas Pipeline Company of America (Midcontinent), the CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), Panhandle Eastern Pipeline (Texas, Oklahoma) and Southern Star Central Gas Pipeline (Texas, Oklahoma, Kansas) with respect to our properties in the Cherokee Basin, the CenterPoint Energy Gas Transmission (East) for our properties in the Woodford Shale, and the spot market prices applicable to our natural gas production. Historically, pricing for natural gas production has been volatile and unpredictable and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside our control, including weather, economic quantity conditions, and the total supply of oil and natural gas for sale in the market.

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

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	(Decrease)	Fair Value	Increase
			(in 000's)		
Impact of changes in commodity prices on derivative commodity instruments June 30, 2008	$ (158,635)	$ (176,877)	$ (18,242)	$ (129,096)	$ 29,539

Interest Rate Risk

At June 30, 2008, we had debt outstanding of $216.0 million, which incurred interest at a rate of LIBOR plus an applicable margin between 1.25% and 2.00% based on utilization. At June 30, 2008, the three-month LIBOR interest rate was 2.78%. 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%, 4.805%, 4.58%, and 4.56% on $16.5 million, $45.0 million, $29.5 million, $11.0 million, and $7.5 million, respectively, of our outstanding debt through February 20, 2010, September 20, 2010, October 19, 2010, August 20, 2010, and October 22, 2010, respectively. At June 30, 2008, the carrying value and fair value of our debt is $216.0 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 June 30, 2008	$ (3,156)	$ (3,404)	$ (248)	$ (2,908)	$ 248

Item 4. Controls and Procedures

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

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

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

Changes in Internal Control over Financial Reporting. During the quarter ended June 30, 2008, 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.

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 other than as disclosed in Note 11 on page 16, Note 16 on page 18, and in Items 1 and 1A of our Annual Report on Form 10-K ("2007 Form 10-K") for the year ended December 31, 2007, filed on March 4, 2008. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under various environmental protection statutes or other regulations to which we are subject.

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in Item 1A. to Part I of our 2007 Form 10-K other than those disclosed 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 below and in our 2007 Form 10-K. 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.

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

During periods of increased inflation or stagflation, our costs of doing business could increase, including increases in the variable interest rates we pay on amounts we borrow under our reserve-based credit facilities. In addition, as we hedged a large percentage of our future expected production volumes, the cash flow generated by that future hedged production will be capped. If any of our operating, administrative or capital costs were to increase as a result of an increase in inflation or stagflation, such a cap could have a material adverse effect on our business, results of operations, financial condition, the ability to make cash distributions to unitholders, and the trading price of our 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 oil and natural gas prices;
- the discovery, estimation, development and replacement of oil and natural gas reserves;
- our business, financial and operational strategy;
- our drilling locations;
- technology;
- our cash flow, liquidity and financial position;
- the impact from any termination of the Robinson's Bend sharing arrangement;
- our hedging program and our derivative positions;
- our production volumes;
- our lease operating expenses, general and administrative costs and finding and development costs;
- the availability of drilling and production equipment, labor and other services;
- our future operating results;
- our prospect development and property acquisitions;
- the marketing of oil and natural gas;
- competition in the oil and natural gas industry;
- inflation and interest rates;
- the impact of weather and the occurrence of natural disasters such as fires, floods, hurricanes, tornados, earthquakes, snow and ice storms and other catastrophic events and natural disasters;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas producing countries; 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.

Item 3. Defaults Upon Senior Securities

None.

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

None.

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 months ended June 30, 2008 and June 30, 2007 and the six months ended June 30, 2008 and June 30, 2007

Consolidated Balance Sheets—Constellation Energy Partners LLC at June 30, 2008 and December 31, 2007

Consolidated Statements of Cash Flows—Constellation Energy Partners LLC for the six months ended June 30, 2008 and June 30, 2007

Consolidated Statements of Changes in Members' Equity and Comprehensive Income (Loss)—Constellation Energy Partners LLC for the six months ended June 30, 2008

Notes to Consolidated Financial Statements

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EXHIBIT INDEX

Exhibit Number	Description	
*31.1	—	Certification of Chief Executive Officer, Chief Operating Officer and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	—	Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	—	Certification of Chief Executive Officer, Chief Operating Officer and President of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	—	Certification of Chief Financial Officer and Treasurer of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

SIGNATURE

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

CONSTELLATION ENERGY PARTNERS LLC
(REGISTRANT)

Date: August 8, 2008	By	/s/ Charles C. Ward
		Chief Financial Officer and Treasurer and as Principal Financial Officer of Registrant

Exhibit 31.1

CONSTELLATION ENERGY PARTNERS LLC

CERTIFICATION

I, Stephen R. Brunner, 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) 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

(d) 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: August 8, 2008

/s/ Stephen R. Brunner

Stephen R. Brunner
Chief Executive Officer, Chief Operating Officer and President

Exhibit 31.2

CONSTELLATION ENERGY PARTNERS LLC

CERTIFICATION

I, Charles C. Ward, 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) 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

(d) 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: August 8, 2008

/s/ Charles C. Ward

Charles C. Ward
Chief Financial 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, Stephen R. Brunner, Chief Executive Officer, Chief Operating 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 June 30, 2008 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/ Stephen R. Brunner
Stephen R. Brunner
Chief Executive Officer, Chief Operating Officer and President

Date: August 8, 2008

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, Charles C. Ward, Chief Financial 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 June 30, 2008 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/ Charles C. Ward
Charles C. Ward
Chief Financial Officer and Treasurer

Date: August 8, 2008