Constellation Energy Partners LLC
Form 10-Q
August 05, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2011

OR

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

For the transition period from to .

Commission File Number 001-33147

Constellation Energy Partners LLC

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**11-3742489**
(State of organization)	**(I.R.S. Employer Identification No.)**
1801 Main Street, Suite 1300 Houston, Texas	**77002**
(Address of Principal Executive Offices)	**(Zip Code)**

Telephone Number: (832) 308-3700

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 x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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 the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company x

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

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 August 5, 2011: 23,768,193 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, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In 000 s except unit data)			
Revenues				
Natural gas, oil and liquids sales	$ 68,080	$ 27,078	$ 93,993	$ 56,315
Gain / (Loss) from mark-to-market activities (see Note 4)	(43,656)	(4,549)	(53,765)	30,732
Total revenues	24,424	22,529	40,228	87,047
Expenses:				
Operating expenses:				
Lease operating expenses	6,602	7,729	14,022	15,692
Cost of sales	542	585	1,061	1,357
Production taxes	660	677	1,431	1,802
General and administrative	4,012	4,188	8,235	9,250
Exploration costs		224	131	447
(Gain) / Loss on sale of assets	14	(5)	21	(13)
Depreciation, depletion, and amortization	5,893	26,733	11,758	53,981
Accretion expense	226	205	452	412
Total operating expenses	17,949	40,336	37,111	82,928
Other expenses (income)				
Interest expense	2,691	3,275	5,214	6,814
Interest expense-(Gain)/Loss from mark-to-market activities (see Note 4)	505	113	(165)	630
Interest (income)		(1)	(1)	(1)
Other expense (income)	(68)	(102)	(126)	(290)
Total other expenses / (income)	3,128	3,285	4,922	7,153
Total expenses	21,077	43,621	42,033	90,081
Net income (loss)	$ 3,347	$ (21,092)	$ (1,805)	$ (3,034)
Other comprehensive income (loss)	(1,885)	(4,264)	(2,585)	(9,550)
Comprehensive income (loss)	$ 1,462	$ (25,356)	$ (4,390)	$ (12,584)
Earnings (loss) per unit (see Note 2)				
Earnings (loss) per unit Basic	$ 0.14	$ (0.87)	$ (0.07)	$ (0.12)
Units outstanding Basic	24,273,244	24,538,151	24,291,246	24,271,742
Earnings (loss) per unit Diluted	$ 0.14	$ (0.87)	$ (0.07)	$ (0.12)
Units outstanding Diluted	24,273,244	24,538,151	24,291,246	24,271,742

Distributions declared and paid per unit	$ 0. 00	$ 0. 00	$ 0.00	$ 0.00

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

(Unaudited)

	June 30, 2011	December 31, 2010
	(In 000 s)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 13,466	$ 7,892
Accounts receivable	8,143	7,371
Prepaid expenses	1,435	1,315
Risk management assets (see Note 4)	21,715	36,513
Other	1,000	
Total current assets	45,759	53,091
Oil and natural gas properties (See Note 6)		
Oil and natural gas properties, equipment and facilities	778,917	774,060
Material and supplies	1,595	2,073
Less accumulated depreciation, depletion, amortization, and impairments	(510,760)	(499,214)
Net oil and natural gas properties	269,752	276,919
Other assets		
Debt issue costs (net of accumulated amortization of $5,788 at June 30, 2011 and $4,888 at December 31, 2010)	3,046	3,727
Risk management assets (see Note 4)	5,685	46,986
Other non-current assets	3,398	3,654
Total assets	$ 327,640	$ 384,377
LIABILITIES AND MEMBERS EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 1,192	$ 1,418
Accrued liabilities	6,465	10,369
Royalty payable	2,807	2,605
Risk management liabilities (see Note 4)	226	141
Total current liabilities	10,690	14,533
Other liabilities		
Asset retirement obligation	13,523	13,024
Other non-current liabilities	79	
Debt	115,500	165,000
Total other liabilities	129,102	178,024
Total liabilities	139,792	192,557
Commitments and contingencies (See Note 8)		
Class D Interests	6,667	6,667
Members equity		
Class A units, 485,537 and 487,750 shares authorized, issued and outstanding, respectively	3,457	3,485

Class B units, 24,124,378 and 24,298,763 shares authorized, respectively, and 23,791,328 and 23,899,758 issued and outstanding, respectively	169,389	170,748
Accumulated other comprehensive income	8,335	10,920
Total members equity	181,181	185,153
Total liabilities and members equity	$ 327,640	$ 384,377

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, 2011	Six months ended June 30, 2010
	(In 000 s)	
Cash flows from operating activities:		
Net income (loss)	$ (1,805)	$ (3,034)
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion and amortization	11,758	53,981
Amortization of debt issuance costs	900	969
Accretion expense	452	412
Equity (earnings) losses in affiliate	(162)	(292)
(Gain) Loss from disposition of property and equipment	21	(13)
Bad debt expense	8	
(Gain) Loss from mark-to-market activities	53,600	(30,102)
Unit-based compensation programs	714	1,030
Changes in Assets and Liabilities:		
Change in net risk management assets and liabilities		
(Increase) decrease in accounts receivable	(780)	1,352
(Increase) decrease in prepaid expenses	(74)	(24)
(Increase) decrease in other assets	(792)	(2)
Increase (decrease) in accounts payable	(227)	206
Increase (decrease) in payable to affiliate		(182)
Increase (decrease) in accrued liabilities	(3,746)	(3,246)
Increase (decrease) in royalty payable	202	(1,721)
Increase (decrease) in other liabilities	79	
Net cash provided by operating activities	60,148	19,334
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash acquired	280	(504)
Development of oil and natural gas properties	(4,651)	(2,261)
Proceeds from sale of equipment	56	29
Distributions from equity affiliate	230	115
Net cash (used in) investing activities	(4,085)	(2,621)
Cash flows from financing activities:		
Members distributions		
Proceeds from issuance of debt		
Repayment of debt	(49,500)	(15,000)
Units tendered by employees for tax withholdings	(296)	(301)
Equity issue costs	(46)	(2)
Debt issue costs	(647)	(50)
Net cash (used in) financing activities	(50,489)	(15,353)
Net increase (decrease) in cash	5,574	1,360
Cash and cash equivalents, beginning of period	7,892	11,337

Cash and cash equivalents, end of period	$ 13,466	$ 12,697
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 116	$ 2,153
Cash received during the period for interest	$ 1	$ 1
Cash paid during the period for interest	$ (3,035)	$ (3,696)

See accompanying notes to consolidated financial statements.

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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, December 31, 2010	487,750	$ 3,485	23,899,758	$ 170,748	$ 10,920	$ 185,153
Distributions						
Units tendered by employees for tax withholding	(2,094)	(6)	(102,581)	(290)		(296)
Change in fair value of commodity hedges					99	99
Cash settlement of commodity hedges					(2,684)	(2,684)
Unit-based compensations programs	(119)	14	(5,849)	700		714
Net income (loss)		(36)		(1,769)		(1,805)
Balance, June 30, 2011	485,537	$ 3,457	23,791,328	$ 169,389	$ 8,335	$ 181,181

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, 2011, are unaudited, but in the opinion of management include all adjustments (consisting only of normal recurring adjustments) necessary for a fair statement 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, 2010, which was filed on February 25, 2011. Certain amounts in the consolidated financial statements and notes thereto have been reclassified to conform to the 2011 financial statement presentation.

Constellation Energy Partners LLC (CEP , we , us , our or the Company) was organized as a limited liability company on February 7, 2005, u the laws of the State of Delaware. We completed our initial public offering on November 20, 2006, and trade on the NYSE Arca under the symbol CEP . We are 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, 2011, affiliates of Constellation own all of our Class A units, all of the Class C management incentive interests, approximately 25% of our Class B common units and all of our Class D interests.

We are currently focused on the development and acquisition of oil and natural gas properties in the Black Warrior Basin in Alabama, the Cherokee Basin in Kansas and Oklahoma, the Woodford Shale in Oklahoma, and the Central Kansas Uplift in Kansas and Nebraska.

Accounting policies used by us conform to GAAP. The accompanying financial statements include the accounts of us and our wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. We operate our oil and natural gas properties as one business segment: the exploration, development and production of oil and natural gas. Our management evaluates performance based on one business segment as there are not different economic environments within the operation of our oil and natural gas properties.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our significant accounting policies are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2010.

Earnings per Unit

Basic earnings per unit (EPU) are computed by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. At June 30, 2011, we had 485,537 Class A units and 23,791,328 Class B units outstanding. Of the Class B units, 1,183,959 units are restricted unvested common units granted and outstanding.

The following table presents earnings per common unit amounts:

	Income	**Units**	**Per Unit Amount**
	(In 000 s except unit data)		
For the three months ended June 30, 2011			
Basic EPU:			
Income (loss) allocable to unitholders	$ 3,347	24,273,244	$ 0.14
Diluted EPU:			

Income (loss) allocable to common unitholders	$ 3,347	24,273,244	$ 0.14

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	Income	Units	Per Unit Amount
	(In 000 s except unit data)		
For the six months ended June 30, 2011			
Basic EPU:			
Income (loss) allocable to unitholders	$ (1,805)	24,291,246	$ (0.07)
Diluted EPU:			
Income (loss) allocable to common unitholders	$ (1,805)	24,291,246	$ (0.07)

	Income	Units	Per Unit Amount
	(In 000 s except unit data)		
For the three months ended June 30, 2010			
Basic EPU:			
Income (loss) allocable to unitholders	$ (21,092)	24,538,151	$ (0.87)
Diluted EPU:			
Income (loss) allocable to common unitholders	$ (21,092)	24,538,151	$ (0.87)

	Income	Units	Per Unit Amount
	(In 000 s except unit data)		
For the six months ended June 30, 2010			
Basic EPU:			
Income (loss) allocable to unitholders	$ (3,034)	24,271,742	$ (0.12)
Diluted EPU:			
Income (loss) allocable to common unitholders	$ (3,034)	24,271,742	$ (0.12)

3. NEW ACCOUNTING PRONOUNCEMENTS

In January 2010, the FASB issued its final guidance on additional supplemental fair value disclosures. Two new disclosures will be required: (1) a gross presentation of activities (purchases, sales, and settlements) within the Level 3 roll forward reconciliation, which will replace the net presentation format, and (2) detailed disclosures about the transfers between Level 1 and 2 measurements. The guidance also provides several clarifications regarding the level of disaggregation and disclosures about inputs and valuation techniques. The new disclosures are effective for calendar year-end companies, except for the Level 3 gross activity disclosures, which were effective the first quarter of 2011. The adoption of this new guidance did not have a material impact on our financial statements or our disclosures.

In February 2010, the FASB amended its guidance on subsequent events. SEC filers are now not required to disclose the date through which an entity has evaluated subsequent events. The amended guidance was effective upon issuance. The adoption of this guidance did not have an impact on our financial statements or our disclosures.

New Accounting Pronouncements Issued But Not Yet Adopted

In June 2011, the FASB issued a final standard (ASU 2011-05) that requires entities to present net income and other comprehensive income in either a single continuous statement or in two separate, but consecutive, statements of net income and other comprehensive income. The option to present items of other comprehensive income in the statement of changes in equity is eliminated. The adoption of this standard will not have a material impact on our financial statements or our disclosures.

In May 2011, the FASB issued ASU 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs*, and the IASB issued IFRS 13, *Fair Value Measurement* (together, the new guidance). The new guidance results in a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between U.S. GAAP and IFRS. The new guidance changes some fair value measurement principles and disclosure requirements and is effective for interim and annual periods beginning on or after December 15, 2011, with early adoption prohibited. The adoption of this new guidance will not have an impact on our financial statements or our disclosures.

As of June 30, 2011, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. We are currently reviewing the recently issued standards and interpretations but none are expected to have a material impact on our financial statements.

4. DERIVATIVE AND FINANCIAL INSTRUMENTS

Mark-to-Market Activities

We have hedged a portion of our expected natural gas and oil sales from currently producing wells through December 2015 and entered into hedging arrangements in the form of interest rate swaps to reduce the impact of volatility stemming from changes in the London interbank offered rate (LIBOR) on $93.0 million of our outstanding debt for various maturities extending through November 2014. All of our derivatives were accounted for as mark-to-market activities as of June 30, 2011.

For the six months ended June 30, 2011 and 2010, we recognized mark-to-market losses of approximately $53.7 million and mark-to-market gains of approximately $30.7 million, respectively, in connection with our commodity derivatives. For the six months ended June 30, 2011 and 2010, we recognized a mark-to-market gain of approximately $0.2 million and a loss of $0.6 million, respectively, in connection with our interest rate derivatives. At June 30, 2011 and December 31, 2010, the fair value of our derivatives accounted for as mark-to-market activities amounted to a net asset of approximately $27.2 million and a net asset of approximately $83.4 million, respectively.

Accumulated Other Comprehensive Income

Prior to the first quarter of 2009, we accounted for certain of our commodity and interest rate derivatives as cash flow hedging activities. The value of the cash flow hedges included in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets was an unrecognized gain of approximately $8.3 million and $10.9 million at June 30, 2011 and December 31, 2010, respectively. We expect that the unrecognized gain will be reclassified from accumulated other comprehensive income (loss) (AOCI) to the income statement in the following periods:

For the Quarter Ended	Commodity Derivatives	Non-performance Risk	Total AOCI
		(In 000 s)	
September 30, 2011	$ 1,749	$ (74)	$ 1,675
December 31, 2011	1,283	(60)	1,223
March 31, 2012	718	(22)	696
June 30, 2012	1,928	(66)	1,862
September 30, 2012	1,721	(63)	1,658
December 31, 2012	1,271	(50)	1,221
Total	$ 8,670	$ (335)	$ 8,335

Hedge Restructuring

During the second quarter of 2011, we amended our existing NYMEX swap agreements to reset the NYMEX fixed-for-floating price to $5.75 per MMBtu for our natural gas production from January 2012 through December 2014. In conjunction with the transaction, we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million, which increased our reported operating cash flows. For tax purposes, the one-time cash payment from our swap counterparties will be amortized over the remaining life of the NYMEX contracts in accordance with the timing of the actual settlement of delivery of natural gas per the swap agreements.

Fair Value Measurements

We measure fair value of our financial and non-financial assets and liabilities on a recurring basis. Accounting standards define fair value, establish a framework for measuring fair value and require certain disclosures about fair value measurements for assets and liabilities measured on a recurring basis. All of our derivative instruments are recorded at fair value in our financial statements. 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.

The following hierarchy 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.

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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.

Our 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 we are required 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 tables set forth by level within the fair value hierarchy our assets and liabilities that were measured at fair value on a recurring basis as of June 30, 2011 and December 31, 2010.

	Commodity		Interest rate	Netting and Cash	Total Net Fair
At June 30, 2011	**Level 1**	**Level 2**	**Level 3**	**Collateral***	**Value**
			(In 000 s)		
Risk management assets	$	$ 30,808	$ (3,408)	$	$ 27,400
Risk management liabilities		(226)		$	(226)
Total	$	$ 30,582	$ (3,408)	$	$ 27,174

* *We currently use our reserve-based credit facility to provide credit support for our derivative transactions and therefore we do not post cash collateral with our counterparties.*

	Commodity		Interest rate	Netting and Cash	Total Net Fair
At December 31, 2010	**Level 1**	**Level 2**	**Level 3**	**Collateral***	**Value**
			(In 000 s)		
Risk management assets	$	$ 87,072	$ (3,573)	$	$ 83,499
Risk management liabilities		(141)			(141)
Total	$	$ 86,931	$ (3,573)	$	$ 83,358

* *We currently use our reserve-based credit facility to provide credit support for our derivative transactions and therefore we do not post cash collateral with our counterparties.*

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

We use observable market data or information derived from observable market data in order to determine the fair value amounts presented above. We currently use our reserve-based credit facility to provide credit support for our derivative transactions. As a result, we do not post cash collateral with our counterparties, and have minimal non-performance credit risk on our liabilities with counterparties. We utilize observable market data for credit default swaps to assess the impact of non-performance credit risk when evaluating our net assets from counterparties. At June 30, 2011, the impact of non-performance credit risk on the valuation of our net assets from counterparties was $0.2 million, of which $0.1 million was reflected as a increase to our non-cash mark-to-market loss and $0.3 million was reflected as a reduction to our accumulated other comprehensive income. At June 30, 2010, the impact of non-performance credit risk on the valuation of our net assets from counterparties was $1.6 million, of which $1.0 million was reflected as a decrease to our non-cash mark-to-market gain and $0.6 million was reflected as a reduction to our AOCI.

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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, 2011 (In 000 s)	Six Months Ended June 30, 2011 (In 000 s)
Balance at beginning of period	$ (2,903)	$ (3,573)
Realized and unrealized gain (loss):		
Included in earnings	(1,031)	(897)
Included in other comprehensive income		
Settlements	526	1,062
Transfers into and (out of) Level 3		
Balance as of June 30, 2011	$ (3,408)	$ (3,408)
Change in unrealized gains relating to derivatives still held as of June 30, 2011	$ (1,031)	$ (897)

	Three Months Ended June 30, 2010 (In 000 s)	Six Months Ended June 30, 2010 (In 000 s)
Balance at beginning of period	$ (4,855)	$ (4,727)
Realized and unrealized gain (loss):		
Included in earnings	(1,130)	(2,873)
Included in other comprehensive income		389
Settlements	1,017	2,243
Transfers into and (out of) Level 3		
Balance as of June 30, 2010	$ (4,968)	$ (4,968)
Change in unrealized gains relating to derivatives still held as of June 30, 2010	$ (1,130)	$ (2,484)

Fair Value of Financial Instruments

At June 30, 2011, 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. We believe the carrying value of long-term debt approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms, which represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties.

The following fair value disclosures are applicable to our financial statements, as of June 30, 2011 and December 31, 2010:

	Location of Asset /	Fair Value of Asset / (Liability) on Balance Sheet (in 000 s)	
Derivative Type	**(Liability) on Balance Sheet**	**Quarter Ended June 30, 2011**	**Year Ended December 31, 2010**
Commodity-MTM	Risk management assets-current	$ 24,876	$ 38,945
Commodity-MTM	Risk management assets-non-current	11,726	60,324
Commodity-MTM	Risk management assets-current	(3,161)	(2,432)

Commodity-MTM	Risk management assets-non-current	(2,633)	(9,765)
Commodity-MTM	Risk management liabilities-current	(226)	(141)
Interest Rate-MTM	Risk management assets-non-current	(3,408)	(3,573)
	Total Derivatives	$ 27,174	$ 83,358

		Amount of Gain / (Loss) in Income (in 000 s)	
Derivative Type	**Location of Gain / (Loss) in Income**	**Quarter Ended June 30, 2011**	**Quarter Ended June 30, 2010**
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ (43,656)	$ (4,549)

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Derivative Type	Location of Asset / (Liability) on Balance Sheet	Fair Value of Asset / (Liability) on Balance Sheet (in 000 s) Quarter Ended June 30, 2011	Year Ended December 31, 2010
Commodity-MTM	Natural gas, oil and liquids sales	49,282	7,088
Interest Rate-MTM	Interest expense-Gain/(Loss) from mark-to-market activities	(505)	(113)
Interest Rate-MTM	Interest expense	(526)	(1,017)
	Total	$ 4,595	$ 1,409

Derivative Type	Location of Gain / (Loss) in Income	Amount of Gain / (Loss) in Income (in 000 s) Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ (53,765)	$ 30,732
Commodity-MTM	Natural gas, oil and liquids sales	59,077	8,986
Interest Rate-MTM	Interest expense-Gain/(Loss) from mark-to-market activities	165	(630)
Interest Rate-MTM	Interest expense	(1,062)	(1,854)
	Total	$ 4,415	$ 37,234

Derivative Type	Location of Gain / (Loss) for Effective and Ineffective Portion of Derivative in Income	Amount of Gain /(Loss) Reclassified from AOCI into Income (in 000 s) Quarter Ended June 30, 2011	Quarter Ended June 30, 2010
Commodity-Cash Flow	Natural gas, oil and liquids sales	1,960	4,319
Interest Rate-Cash Flow	Interest expense		
	Total	$ 1,960	$ 4,319

Derivative Type	Location of Gain / (Loss) for Effective and Ineffective Portion of Derivative in Income	Amount of Gain /(Loss) Reclassified from AOCI into Income (in 000 s) Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Commodity-Cash Flow	Natural gas, oil and liquids sales	2,684	10,047
Interest Rate-Cash Flow	Interest expense		(389)
	Total	$ 2,684	$ 9,658

As of June 30, 2011, we have interest rate swaps on $93.0 million of outstanding debt for various maturities extending through November 2014, various commodity swaps for 28,355,000 MMbtu of natural gas production through December 2014, various basis swaps for 17,338,836 MMbtu of natural gas production in the Cherokee Basin through December 2014, and commodity swaps for 191,765 Bbls of crude oil production through December 2015.

5. DEBT

Reserve-Based Credit Facility

On June 3, 2011, we executed a second amendment to our $350.0 million credit agreement with The Royal Bank of Scotland plc as administrative agent and a syndicate of lenders. The reserve-based credit facility matures on November 13, 2013. Borrowings under the reserve-based credit facility are secured by various mortgages of oil and natural gas properties that we and certain of our subsidiaries own as well as various security and pledge agreements among us and certain of our subsidiaries and the administrative agent. The current lenders and their percentage commitments in the reserve-based credit facility are The Royal Bank of Scotland plc (26.84%), BNP Paribas (21.95%), The Bank of Nova Scotia (21.95%), Societe Generale (14.63%), and ING Capital LLC (14.63%).

The amount available for borrowing at any one time under the reserve-based credit facility is limited to the borrowing base for our oil and natural gas properties. As of June 30, 2011, our borrowing base was $140.0 million. The borrowing base is redetermined semi-annually, and may be redetermined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, together with, among other things, the oil and natural gas prices prevailing at such time. Our next semi-annual borrowing base redetermination is scheduled during the fourth quarter of 2011. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders.

Borrowings under the reserve-based credit facility are available for acquisition, exploration, operation and maintenance of oil and natural gas properties, payment of expenses incurred in connection with the reserve-based credit facility, working capital and general limited liability company purposes. The reserve-based credit facility has a sub-limit of $20.0 million which may be used for the issuance of letters of credit. As of June 30, 2011, no letters of credit are outstanding.

At our election, interest for borrowings are determined by reference to (i) the London interbank rate, or LIBOR, plus an applicable margin between 2.50% and 3.50% per annum based on utilization or (ii) a domestic bank rate (ABR) plus an applicable margin between 1.50% and 2.50% per annum based on utilization plus (iii) a commitment fee of 0.50% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The reserve-based credit facility contains various covenants that limit, among other things, our ability and certain of our subsidiaries ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions.

In addition, we are required to maintain (i) a ratio of Total Net Debt (defined as Debt (generally indebtedness permitted to be incurred by us under the reserve-based credit facility) less Available Cash (generally, cash, cash equivalents, and cash reserves of the Company)) to Adjusted EBITDA (generally, for any period, the sum of consolidated net income for such period plus (minus) 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, exploration costs, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on derivatives and realized (gain) loss on cancelled derivatives, and other similar charges) of not more than 3.50 to 1.0; (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 and current maturities of debt (to the extent such payments are not past due), of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143 (including the current liabilities in respect of the termination of oil and natural gas and interest rate swaps). All financial covenants are calculated using our consolidated financial information.

The reserve-based 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 reserve-based credit facility and a change of control. If an event of default occurs, the lenders will be able to accelerate the maturity of the reserve-based credit facility and exercise other rights and remedies. The reserve-based credit facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the reserve-based credit facility and would be in default, which could cause all of our existing indebtedness to become immediately due and payable.

We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the reserve-based credit facility, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the reserve-based credit facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. As of August 5, 2011, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions.

The reserve-based credit facility permits us to hedge our projected monthly production, provided that (a) for the immediately ensuing twelve month period, the volumes of production hedged in any month may not exceed our reasonable business judgment of the production for such month consistent with the application of petroleum engineering methodologies for estimating proved developed producing reserves based on the then-current strip pricing (provided that such projection shall not be more than 115% of the proved developed producing reserves forecast for the same period derived from the most recent reserve report of our petroleum engineers using the then strip pricing), and (b) for the period beyond twelve months, the volumes of production hedged in any month may not exceed the reasonably anticipated projected production from proved developed producing reserves estimated by our petroleum engineers. The reserve-based credit facility also permits us to hedge the interest rate on up to 90% of the then-outstanding principal amounts of our indebtedness for borrowed money.

The reserve-based credit facility contains no covenants related to our relationship with Constellation or Constellation s right to appoint all of the Class A managers of our board of managers.

Debt Issue Costs

As of June 30, 2011, our unamortized debt issue costs were approximately $3.0 million. These costs are being amortized over the life of the credit facility through November 2013. For the quarter and six months ended June 30, 2011, we accelerated the amortization of $0.4 million in debt issue costs as a result of amending our reserve-based credit facility.

Funds Available for Borrowing

As of June 30, 2011 and 2010, we had $115.5 million and $180.0 million, respectively, in outstanding debt under our reserve-based credit facility. As of June 30, 2011, we had $24.5 million in remaining borrowing capacity under our reserve-based credit facility. See Note 14 for additional information.

Compliance with Debt Covenants

At June 30, 2011, we believe that we were in compliance with the financial covenant ratios contained in our reserve-based credit facility. We monitor compliance on an ongoing basis. As of June 30, 2011, our actual Total Net Debt to annual Adjusted EBITDA ratio was 1.9 to 1.0 as compared with a required ratio of not greater than 3.5 to 1.0, our actual ratio of consolidated current assets to consolidated current liabilities was 4.6 to 1.0 as compared with a required ratio of not less than 1.0 to 1.0, and our actual Adjusted EBITDA to cash interest expense ratio was 10.2 to 1.0 as compared with a required ratio of not less than 2.5 to 1.0.

If we are unable to remain in compliance with the debt covenants associated with our reserve-based credit facility or maintain the required ratios discussed above, we could request waivers from the lenders in our bank group. Although the lenders may not provide a waiver, we could take additional steps in the event of not meeting the required ratios or in the event of a reduction in the borrowing base as determined by the lenders. During 2011, we intend to use our surplus operating cash flows to reduce our outstanding debt. If it becomes necessary to reduce debt by amounts that exceed our operating cash flows, we could further reduce capital expenditures, continue to suspend our quarterly distributions to unitholders, sell oil and natural gas properties, liquidate in-the-money derivative positions, further reduce operating and administrative costs, or take additional steps to increase liquidity. If we become unable to obtain a waiver and were unsuccessful at reducing our debt to the necessary level, our debt could become due and payable upon acceleration by the lenders. To the extent that we do not enter into an agreement to refinance or extend the due date on the reserve-based credit facility, the outstanding debt balance at November 13, 2012, will become a current liability.

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6. OIL AND NATURAL GAS PROPERTIES

Natural gas properties consist of the following:

	June 30, 2011	December 31, 2010
	(In 000 s)	
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 777,243	$ 772,450
Unproved property	762	698
Total property costs	778,005	773,148
Materials and supplies	1,595	2,073
Land	912	912
Total	780,512	776,133
Less: Accumulated depreciation, depletion, amortization and impairments	(510,760)	(499,214)
Natural gas properties and equipment, net	$ 269,752	$ 276,919

Depletion, depreciation, amortization and impairments consisted of the following:

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In 000 s)	
DD&A of oil and natural gas-related assets	$ 11,758	$ 53,981
Total	$ 11,758	$ 53,981

Asset Sales

In the six months ended June 30, 2011, we sold miscellaneous equipment and surplus inventory for approximately $0.1 million and recorded a gain of approximately $0.02 million on the sales.

Useful Lives

Our furniture, fixtures, and equipment are depreciated over a life of one to seven years, buildings are depreciated over a life of twenty years, and pipeline and gathering systems are depreciated over a life of twenty-five to forty years.

Exploration and Dry Hole Costs

Our exploration and dry hole costs were $0.1 million and $0.4 million in the six months ended June 30, 2011 and 2010, respectively. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on our unproved properties.

7. RELATED PARTY TRANSACTIONS

Unit Ownership

Constellation owns a significant number of our units. As of June 30, 2011, CEPM owns all 485,537 of our Class A units, all of our Class D interests, and all of the Class C management incentive interests; and Constellation Energy Partners Holdings, LLC, or CEPH, owns 5,918,894 Class B common units. As of December 31, 2010, CEPM owned all 487,750 of our Class A units and all of the Class C management incentive interests; CEPH owned 5,918,894 Class B common units; and Constellation Holdings, Inc. (or CHI) owned all of our Class D interests.

Each of CEPM, CEPH and CHI is a wholly owned subsidiary of Constellation.

Constellation-Related Announcement

On June 21, 2011, PostRock Energy Corporation (NASDAQ: PSTR) (PostRock) issued a news release announcing that it had agreed to purchase all of Constellation s interests in CEP. PostRock announced that it has agreed to acquire 5,918,894 of our Class B Member Interests, representing approximately 24.5% of that class, along with all of our outstanding Class A, Class C and Class D interests.

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In the news release, PostRock announced that it will pay Constellation $11.25 million of cash, $11.25 million of PostRock common stock and warrants to acquire an additional 1.5 million shares of PostRock common stock at a premium to market. PostRock stated that closing of the transaction is subject to approval of the transaction by the independent managers of CEP and a vote by PostRock s shareholders. In connection with the PostRock vote, PostRock stated that White Deer has pledged the support of its 45% voting interest in PostRock.

In the Purchase Agreement associated with the proposed transaction filed with the SEC by PostRock on June 23, 2011, it provides as a condition precedent to the obligations of each of the buyer and seller thereunder that our board of managers shall have approved the transfer of Constellation s interests in our company to PostRock (i) as provided in the definition of Outstanding in our Second Amended and Restated Operating Agreement, as amended (Operating Agreement) and (ii) for purposes of Section 12.6 of our Operating Agreement and Section 203 of the Delaware General Corporation Law. The conflicts committee of our board of managers is reviewing a request by Constellation that the transfer be approved as provided in the Purchase Agreement, but there can be no assurance that such transfer will be approved as requested. If our board of managers approves the transaction as currently proposed and the proposed Constellation transaction is consummated, PostRock will receive all of CEG s voting rights, including its right to appoint two of the five members of our board of managers.

A subsidiary of Constellation has agreed to reimburse us for any fees and expenses of our board of managers incurred in connection with its review and consideration of the proposed Constellation transaction.

Class C Management Incentive Interests

CEPM holds the Class C management incentive interests in CEP. These management incentive interests represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in our limited liability company agreement) has been achieved and certain other tests have been met. Through the six months ended June 30, 2011, none of these applicable tests have been met, and, as a result, CEPM was not entitled to receive any management incentive interest distributions.

Class D Interests

Our Class D interest special quarterly distributions have been suspended for all quarters commencing on or after January 1, 2008. This suspension includes approximately $4.3 million which represents the aggregate amount of distributions that were suspended for each of the quarterly periods between March 31, 2011 and March 31, 2008. Including the suspended distributions, the remaining undistributed amount of the distributions on the Class D interests yet to be paid is $6.7 million. See Note 14 for additional information.

8. COMMITMENTS AND CONTINGENCIES

In the course of our normal business affairs, we are subject to possible loss contingencies arising from federal, state and local environmental, health and safety laws and regulations. These laws and regulations can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. We are also subject to possible loss contingencies from third-party litigation. As of June 30, 2011, 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, and its subsidiaries, taken as a whole.

Certain of our wells in the Robinson s Bend Field are subject to a net profits interest (NPI) held by Torch Energy Royalty Trust (the Trust) (See Note 10). The royalty payment to the Trust is calculated using a sharing arrangement with a pricing formula that has had the effect of keeping our payments to the Trust lower than if such payments had been calculated based on prevailing market prices. We are 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 our operating results from a termination of the sharing arrangement, a subsidiary of Constellation contributed $8.0 million to us in exchange for all of our Class D interests at the closing of our initial public offering in November 2006 for the purpose of partially protecting the distributions to the common unit holders in the event the sharing arrangement is terminated. This contribution will be returned to a subsidiary of Constellation in 24 special quarterly distributions as long as the sharing agreement remains in effect for the distribution period. As discussed in Note 7 and Note 14, the Class D interest special quarterly distributions have been suspended for all quarters commencing after January 1, 2008.

9. ASSET RETIREMENT OBLIGATION

We recognize the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred if a reasonable estimate of fair value can be made. Each period, we accrete the ARO to its then present value. The associated asset retirement cost (ARC) is capitalized as part of the carrying amount of our natural gas properties equipment and facilities. Subsequently, the ARC is depreciated using a systematic and rational method over the asset s useful life. The AROs recorded by us relate to the plugging and abandonment of natural gas wells, and decommissioning of the gas gathering and processing facilities.

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

The following table is a reconciliation of the ARO:

	June 30, 2011	December 31, 2010
	(In 000 s)	
Asset retirement obligation, beginning balance	$ 13,024	$ 12,129
Liabilities incurred from acquisition of the properties		32
Liabilities incurred	67	83
Liabilities settled	(20)	(42)
Revisions to prior estimates		
Accretion expense	452	822
Asset retirement obligation, ending balance	$ 13,523	$ 13,024

Additional retirement obligations increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Actual expenditures for abandonments of oil and natural gas wells and other facilities reduce the liability for asset retirement obligation. At June 30, 2011, and December 31, 2010, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing asset retirement obligations.

10. NET PROFITS INTEREST

Certain of our 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 Conveyance). We record 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, 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, 2011 and 2010. As a result, no payments were made to the Trust with respect to the NPI for the three months ended June 30, 2011 and 2010. The calculation of the Infill Net Proceeds uses the same methodology as the NPI Net Proceeds

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

Termination of the Trust and Gas Purchase Contract

On January 29, 2008, the unitholders of the Trust voted to terminate the Trust and the trust agreement and authorized the Trustee to wind up, liquidate and distribute the assets held by the Trust under the terms of the trust agreement. The gas purchase contract, by its terms, was also terminated on January 29, 2008 as a result of the termination of the Trust. With the gas purchase contract terminated, we are no longer obligated to sell gas produced from our interest in the Black Warrior Basin pursuant to the gas purchase contract. Notwithstanding the termination of the gas purchase contract, the NPI will continue to burden the Trust Wells, and it should continue to be calculated as if the gas purchase contract were still in effect, regardless of what proceeds may actually be received by us as the seller of the gas. As a result of the termination of the Trust, certain water gathering, separation and disposal costs, which are a component of the NPI calculation, increased from $0.53 per barrel to $1.00 per barrel pursuant to the Water Gathering and Disposal Agreement dated August 9, 1990, as amended; the amounts of the water gathering, separation and disposal costs are set forth in such agreement. As further discussed below, the Water Gathering and Disposal Agreement was amended effective June 13, 2011.

Litigation Related to Trust Termination

On January 8, 2009, we were served by Trust Venture, on behalf of the Trust, with a purported derivative action filed in the Circuit Court of Tuscaloosa County, Alabama (the Court). The lawsuit related to the non-operating NPI held by the Trust on certain wells owned by Robinson s Bend Production II, LLC (RBP II), a subsidiary of the Company, in the Robinson s Bend Field in Alabama, and alleged, among other things, a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserted that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit sought unspecified damages and an accounting of the NPI. The Court made the Trust a nominal party to the lawsuit. On February 4, 2011, the parties entered into a settlement agreement subject to approval by the Court. At a preliminary hearing on February 17, 2011, the Court approved a form of notice of a settlement among the parties to be sent by the Trust to its unitholders. On April 13, 2011, the Court approved the settlement and the effective date of the settlement was June 13, 2011. The settlement with Trust Venture, its successor and the Trust provided, among other things:

- RBP II made a payment of $1.2 million to reimburse Trust Venture and its successor for their legal fees and expenses incurred in prosecuting the lawsuit;

- RBP II made an irrevocable offer to purchase the NPI relating to the Robinson s Bend Field from the Trust for at least $1 million, when it is separately offered for sale by the Trust at public auction within 180 days of the effective date of the settlement, with such bid amount to be deposited by RBP II in a third-party escrow account pending the public auction. RBP II, as well as any other bidders at the auction, shall have a right to submit a higher topping bid;

- The parties agreed that the cumulative deficit balance in the NPI account is approximately $5.8 million as of September 30, 2010, and that no further payments will be due to the Trust with respect to the NPI unless and until the cumulative deficit balance is reduced to zero;

- Trust Venture and its successor agreed, on behalf of the Trust, that all prior and current calculations, charges and deductions contained in such cumulative deficit NPI balance are in compliance with the terms of the Conveyance and, to the extent applicable thereunder, do not exceed competitive contract charges prevailing in the area for any such operations and services;

- The Water Gathering and Disposal Agreement between RBP II and another subsidiary of the Company was amended to reduce the fee from $1.00 per barrel to $0.53 per barrel beginning on the first day of the month following the effective date of the settlement and to extend the term for an additional ten years, and Trust Venture and its successor agreed, on behalf of the Trust, that the fees under such agreement do not exceed competitive contract charges prevailing in the area for the operations and services provided under such agreement during the extended term of such agreement; and

- A mutual release among the parties became effective and the lawsuit was dismissed with prejudice.

11. UNIT-BASED COMPENSATION

We recognized approximately $0.7 million and $1.0 million of expense related to our unit-based compensation plans in the six months ended June 30, 2011, and June 30, 2010, respectively. As of June 30, 2011, we had approximately $3.4 million in unrecognized compensation expense related to our unit-based compensation plans expected to be recognized through the first quarter of 2015.

Unit-Based Awards Granted in 2011

In the second quarter of 2011, the compensation committee and board of managers granted approximately 31,000 unit-based awards under our 2009 Omnibus Incentive Compensation Plan to our named executive officers and other key employees. These unit-based awards will be settled in cash instead of units and the employees may earn between 0% and 200% of the number of awards granted based on the achievement of absolute CEP unit price targets during a three-year performance period from January 2011 through December 2013. CEP unit price targets and corresponding cash payout levels are as follows:

Threshold 50% cash payout at $3.50/CEP unit

Target 100% cash payout at $4.00/CEP unit

Stretch 200% cash payout at $6.00/CEP unit

Cash payouts for results between these points will be interpolated on a linear basis.
Failure to achieve the threshold CEP unit price will result in no cash payout of the awards granted. The determination of the level of achievement and number of awards earned will be based on a calculation of CEP s unit price at the end of the performance period. This price calculation will be based on the average of the closing daily prices for the final 20 trading days of the performance period. In addition, the executive unit-based awards will vest earlier if any of the following events occur: a change of control, a CEG ownership event, death of the executive, delivery by the Company of a disability notice with respect to the executive, or an involuntary termination of the executive (with each of the foregoing terms having the corresponding definitions set forth in the respective employment agreement with the Company). The awards may vest earlier with respect to the other key employees under certain of these circumstances. Any cash payment will be made at the end of the performance period except in the case of certain change of control events, which may accelerate payment. The grants are accounted for in our financial statements as a liability-classified award with the fair value remeasured each reporting period until settlement. At June 30, 2011, the fair market value of these awards was approximately $1.0 million and we recognized approximately $0.1 million in non-cash compensation expenses related to the program. The program is intended to benefit our unitholders by focusing the recipient s efforts on increasing our absolute unit price over the performance period.

12. DISTRIBUTIONS TO UNITHOLDERS

Distributions through June 30, 2011

Beginning in June 2009, we suspended our quarterly distributions to unitholders. For the six months ended June 30, 2011, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions. See Note 14 for additional information.

Distributions through June 30, 2010

For the six months ended June 30, 2010, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions.

13. MEMBERS EQUITY

2011 Equity

At June 30, 2011, we had 485,537 Class A units and 23,791,328 Class B common units outstanding, which included 202,983 unvested restricted common units issued under our Long-Term Incentive Plan and 980,976 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan. See Note 14 for additional information.

At June 30, 2011, we had granted 355,555 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 152,572 have vested.

At June 30, 2011, 125,615 common units have vested out of the 300,000 common units available under our Executive Inducement Bonus Program. This program has now terminated and the remaining 174,385 have been cancelled.

At June 30, 2011, we had granted 1,411,395 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 430,419 have vested.

For the six months ended June 30, 2011, 104,675 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.3 million, have been returned to their respective plan and are available for future grants.

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2010 Equity

At June 30, 2010, we had 490,515 Class A units and 24,035,241 Class B common units outstanding, which included 426,947 unvested restricted common units issued under our Long-Term Incentive Plan, 83,745 unvested restricted common units issued under our Executive Inducement Bonus Program, and 1,327,219 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan.

At June 30, 2010, we had granted 448,674 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 21,727 have vested.

At June 30, 2010, we had granted 146,551 common units of the 300,000 common units available under our Executive Inducement Bonus Program. Of these grants, 62,807 have vested.

At June 30, 2010, we had granted 1,541,252 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 214,033 have vested.

For the six months ended June 30, 2010, 75,452 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.3 million, have been returned to their respective plan and are available for future grants.

14. SUBSEQUENT EVENTS

The following subsequent events have occurred between June 30, 2011, and August 5, 2011:

Distribution

Our board of managers has suspended the quarterly distribution to our unitholders for the quarter ended June 30, 2011, which continues the suspension we first announced in June 2009.

Class D Interests

We have suspended all quarterly cash contributions with respect to our Class D interests. This suspension, approved by our board of managers, includes the $0.3 million quarterly cash distribution for the three months ended June 30, 2011 and $4.3 million which represents the aggregate amount of distributions that were suspended for each of the quarterly periods between March 31, 2011 and March 31, 2008. The remaining undistributed amount of the distributions on the Class D interests yet to be paid is $6.7 million.

Debt

Funds Available for Borrowing

As of August 5, 2011, we had $109.25 million in outstanding debt under our reserve-based credit facility and we had $30.75 million in remaining borrowing capacity under the reserve-based credit facility. Our next semi-annual borrowing base redetermination is scheduled for the fourth quarter of 2011.

Members Equity

2011 Equity

At August 5, 2011, we had 485,065 Class A units and 23,768,193 Class B units outstanding, which included 149,869 unvested restricted common units issued under our Long-Term Incentive Plan and 968,533 unvested restricted common units under our 2009 Omnibus Incentive Compensation Plan.

At August 5, 2011, we had granted 335,529 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 185,660 have vested.

At August 5, 2011, we had granted 1,408,286 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 439,753 have vested.

Through August 5, 2011, 118,809 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.3 million, have been returned to their respective plan and are available for future grants.

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 our most recent Annual Report on Form 10-K.

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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 as well as related midstream assets. At June 30, 2011, our oil and natural gas reserves were located in the Black Warrior Basin of Alabama, the Cherokee Basin of Kansas and Oklahoma, the Woodford Shale in Oklahoma, and the Central Kansas Uplift in Kansas and Nebraska. Our primary business objective is to create long-term value and to generate stable cash flows allowing us to resume making quarterly distributions to our unitholders. We plan to achieve our objective by executing our business strategy, which is to:

- organically grow our business by increasing reserves and production through what we believe to be low-risk development drilling that focuses on capital efficient production growth;
- reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient hedging programs;
- improve our liquidity position by reducing our outstanding debt level and actively managing our operating expenses; and
- make accretive acquisitions of oil and natural gas properties characterized by a high percentage of proved developed oil and natural gas 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.

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 distributions to our unitholders.

We also face the challenge of oil and natural gas production declines. As a given well s initial reservoir pressures are depleted, oil and natural gas production decreases. We attempt to overcome this natural decline in production by drilling additional wells on our proven undeveloped, probable and possible locations on our existing properties and by acquiring additional reserves when opportunities arise. We will continue to focus on adding reserves through drilling, well recompletions and right-sized 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 seek to maintain or grow our production and our asset base by pursuing both organic growth opportunities and acquisitions of producing oil and natural gas 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.

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

How We Evaluate our Operations

Non-GAAP Financial Measure Adjusted EBITDA

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

depreciation, depletion and amortization;

write-off of deferred financing fees;

asset impairments;

(gain) loss on sale of assets;

accretion expense;

exploration costs;

(gain) loss from equity investment;

unit based compensation programs;

(gain) loss from mark-to-market activities;

unrealized (gain)/loss on derivatives/hedge ineffectiveness; and

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- interest (income) expense, net which includes:
  - interest expense
  - interest expense gain/(loss) mark-to-market activities
  - interest (income)

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 distributions we would 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 a quarterly distribution or 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 (loss) to Adjusted EBITDA, our most directly comparable GAAP performance measure, for each of the periods presented:

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010
	(In 000 s)			
Reconciliation of Net Income (Loss) to Adjusted EBITDA:				
Net income (loss)	$ 3,347	$ (21,092)	$ (1,805)	$ (3,034)
Adjusted by:				
Interest expense/(income), net	3,196	3,387	5,048	7,443
Depreciation, depletion and amortization	5,893	26,733	11,758	53,981
Accretion expense	226	205	452	412
(Gain)/Loss on sale of assets	14	(5)	21	(13)
Exploration costs		224	131	447
Unit-based compensation programs	341	593	714	1,030
(Gain)/Loss on mark-to-market activities	43,656	4,549	53,765	(30,732)
Adjusted EBITDA	$ 56,673	$ 14,594	$ 70,084	$ 29,534

During the second quarter of 2011, we executed a transaction to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production from January 2012 through 2014. In conjunction with the transaction, we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million, which increased our Adjusted EBITDA and reported operating cash flows. The proceeds were used, together with cash on hand, to reduce our outstanding debt balance under our reserve-based credit facility by $42.0 million. We also executed a second amendment of our $350.0 million credit agreement with The Royal Bank of Scotland plc, as administrative agent, and a syndicate of lenders, which extended the maturity date of the reserve-based credit facility to November 13, 2013. Our reserve-based credit facility is further discussed in Liquidity and Capital Resources Reserve-Based Credit Facility and our open derivative positions are further discussed in Cash Flow From Operations-Open Commodity Hedge Positions.

Significant Operational Factors

Realized Prices. Our average realized price for the six months ended June 30, 2011, including hedge settlements, was $13.49 per Mcfe and $4.63 per Mcfe without hedge settlements. After deducting the cost of sales associated with third party gathering, the average realized prices were $13.34 per Mcfe including hedge settlements and $4.47 per Mcfe excluding hedge settlements.

Production. Our production for the six months ended June 30, 2011, was approximately 7.0 Bcfe, or an average of 38,503 Mcfe per day compared with approximately 7.6 Bcfe, or an average of 42,017 Mcfe per day for the six months ended June 30, 2010. This 2011 production is lower than the production for the same period in 2010 because our capital spending has been below the maintenance capital expenditures required to offset the natural production declines associated with our existing wells and severe weather in our operating areas during 2011, offset by the impact of our December 2010 acquisition of oil properties in the Central Kansas Uplift.

Capital Expenditures and Drilling Results. During the first six months of 2011, we spent approximately $4.4 million in cash capital expenditures, consisting of $4.7 million in development expenditures offset by the receipt of $0.3 million in post-closing adjustments for our December 2010 acquisition of oil properties in the Central Kansas Uplift. We have completed 10 net wells and 24 net recompletions in the Cherokee Basin and completed 5 net wells in the Black Warrior Basin during 2011. We had 2 net wells in progress, including 1 in the Black Warrior Basin and 1 in the Central Kansas Uplift, and 14 net recompletions in progress at June 30, 2011.

Reduction of Outstanding Debt. Between the end of the third quarter of 2009 and August 5, 2011, we reduced our outstanding debt from $220.0 million to $109.25 million or by 50.3%. For the remainder of 2011, we plan to continue to use our excess operating cash flows to further reduce our outstanding debt balance to a level below $100.0 million.

Hedging Activities. As of June 30, 2011, all of our derivatives are accounted for as mark-to-market activities. For the six months ended June 30, 2011, the unrealized non-cash mark-to-market loss was approximately $53.7 million as compared to an unrealized non-cash mark-to-market gain of $30.7 million for the same period in 2010.

On June 3, 2011 we executed a transaction to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production from January 2012 through 2014. In conjunction with the transaction, we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million, which was used, together with cash on hand, to reduce our outstanding debt balance under our reserve-based credit facility by $42.0 million.

We experience earnings volatility as a result of using the mark-to-market accounting method for our commodity derivatives used to hedge our exposure to changes in commodity prices or basis differentials. This accounting treatment can cause earnings volatility as the positions for future oil and 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 cash settled as the commodities are produced and sold. We do not enter into speculative trading positions and we only use derivatives to lock in the future sales price for a portion of our expected oil and natural gas production. Increases in the market price of oil or 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 oil or 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 commodity sale is not marked-to-market and therefore is not reflected as Natural Gas, Oil, and Liquids Sales or as an Accounts Receivable in our financial statements. This mismatch impacts our reported Results of Operations and our reported working capital position until the commodity derivatives are cash settled and the oil and 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 oil and natural gas production at the fixed future sales price for our hedge. When our derivative positions are cash settled as the related commodities are produced and sold, the realized gains and losses of those derivative positions are included in our Statement of Operations as Natural Gas, Oil and Liquids Sales. Further detail of our commodity derivative positions and their accounting treatment is outlined below in Cash Flow From Operations-Open Commodity Hedge Positions.

Torch Royalty NPI Litigation Settlement. We entered into a settlement agreement with the parties to the Torch derivative action litigation, subject to the approval of the Court. On April 13, 2011, the Court approved the settlement, and the effective date of the settlement was June 13, 2011. The settlement agreement generally provides for (i) a settlement of all claims in the lawsuit and a mutual release of all claims among the parties through the effective date of the settlement, (ii) an agreement as to the cumulative deficit balance in the NPI account through September 30, 2010 of approximately $5.8 million, (iii) an amendment to the Water Gathering and Disposal Agreement to establish a $0.53 per barrel fee for a ten year period from the first of the month following the effective date of the settlement, (iv) payment by RBP II of $1.2 million to reimburse Trust Venture for its fees and expenses in prosecuting the lawsuit, and (v) an irrevocable offer by RBP II to purchase the NPI from the Trust for $1.0 million in an auction of the NPI by the Trust, subject to the Trust auctioning the NPI within 180 days of the effective date of the settlement, with the purchase price to be held in escrow. The $1.2 million to reimburse Trust Venture for its fees and expenses in prosecuting the lawsuit and the $1.0 million deposit into an escrow account to support the offer to purchase the NPI were both paid in June 2011. Because the NPI was granted to the Trust by a predecessor-in-interest to RBP II, if RBP II is the winning bidder in the auction of the NPI by the Trust, we would expect the NPI to be extinguished once the NPI is assigned to RBP II by the Trust. If the Trust sells the NPI to another party, the Water Gathering and Disposal Agreement would have a fee of $0.53 a barrel for an additional 10 year term from the first day of the month following the effective date of the settlement. If we had calculated the NPI for the second quarter of 2011 with the prevailing gas prices during the quarter and the $0.53 a barrel water gathering and disposal fee, the cumulative deficit balance would have grown to larger than the approximately $7.4 million cumulative deficit balance through March 31, 2011.

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Impact of Alabama Tornado. On April 27, 2011, a major EF5 tornado hit Tuscaloosa County, Alabama, which is the core of our operations in the Black Warrior Basin. Our operations did not sustain major physical damage and none of our employees or their families were injured or killed. However, immediately after the tornado, the southern part of our Black Warrior operations was without power, causing us to shut-in 265 of our 493 producing wells. Power supplies in the area were restored after major repairs to damaged infrastructure were completed, including repairs to the sub-station serving our operations. We provided a notice of an event of force majeure to the two purchasers of our natural gas production in Alabama - J.P. Morgan Ventures Energy Corporation and Enterprise Alabama Intrastate, LLC. Our production, which was only lowered by approximately 11 Mmcf, was substantially restored by May 1, 2011. We incurred a limited amount of additional operating expenses to restore power to our wells and to clean up our lease sites.

Significant Market Factors

Constellation Announcement. On April 28, 2011, Exelon Corporation agreed to buy Constellation for approximately $7.9 billion in stock. The proposed transaction needs approval by state utility regulators in Maryland, New York, and Texas, in addition to the shareholders of both companies and federal regulators. Constellation is our former sponsor and currently owns all of our outstanding Class A units, approximately 5.9 million Class B common units, all of our Class D interests, and all of the Class C Management Incentive Interests.

Constellation-Related Announcement. On June 21, 2011, PostRock Energy Corporation (NASDAQ: PSTR) (PostRock) issued a news release announcing that it had agreed to purchase all of Constellation s interests in CEP. PostRock announced that it has agreed to acquire 5,918,894 of our Class B Member Interests, representing approximately 24.5% of that class, along with all of our outstanding Class A, Class C and Class D interests.

In the news release, PostRock announced that it will pay Constellation $11.25 million of cash, $11.25 million of PostRock common stock and warrants to acquire an additional 1.5 million shares of PostRock common stock at a premium to market. PostRock stated that closing of the transaction is subject to approval of the transaction by the independent managers of CEP and a vote by PostRock s shareholders. In connection with the PostRock vote, PostRock stated that White Deer has pledged the support of its 45% voting interest in PostRock.

In the Purchase Agreement associated with the proposed transaction filed with the SEC by PostRock on June 23, 2011, it provides as a condition precedent to the obligations of each of the buyer and seller thereunder that our board of managers shall have approved the transfer of Constellation s interests in our company to PostRock (i) as provided in the definition of Outstanding in our Second Amended and Restated Operating Agreement, as amended (Operating Agreement) and (ii) for purposes of Section 12.6 of our Operating Agreement and Section 203 of the Delaware General Corporation Law. The conflicts committee of our board of managers is reviewing a request by Constellation that the transfer be approved as provided in the Purchase Agreement, but there can be no assurance that such transfer will be approved as requested. If our board of managers approves the transaction as currently proposed and the proposed Constellation transaction is consummated, PostRock will receive all of CEG s voting rights, including its right to appoint two of the five members of our board of managers.

A subsidiary of Constellation has agreed to reimburse us for any fees and expenses of our board of managers incurred in connection with its review and consideration of the proposed Constellation transaction.

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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, 2011	June 30, 2010	Variance $	Variance %	June 30, 2011	June 30, 2010	Variance $	Variance %
Revenues:								
Natural gas sales	$ 65,253	$ 25,852	$ 39,401	152.4%	$ 89,086	$ 54,017	$ 35,069	64.9%
Oil and liquids sales	$ 2,827	1,226	$ 1,601	130.6%	$ 4,907	2,298	$ 2,609	113.5%
Gain (Loss) from mark-to-market activities	(43,656)	(4,549)	(39,107)	859.7%	(53,765)	30,732	(84,497)	(274.9)%
Total revenues	24,424	22,529	1,895	8.4%	40,228	87,047	(46,819)	(53.8)%
Operating expenses:								
Lease operating expenses	6,602	7,729	(1,127)	(14.6)%	14,022	15,692	(1,670)	(10.6)%
Cost of sales	542	585	(43)	(7.4)%	1,061	1,357	(296)	(21.8)%
Production taxes	660	677	(17)	(2.5)%	1,431	1,802	(371)	(20.6)%
General and administrative	4,012	4,188	(176)	(4.2)%	8,235	9,250	(1,015)	(11.0)%
Exploration costs		224	(224)	(100.0)%	131	447	(316)	(70.7)%
(Gain) loss on sale of assets	14	(5)	19	(380.0)%	21	(13)	34	(261.5)%
Depreciation, depletion and amortization	5,893	26,733	(20,840)	(78.0)%	11,758	53,981	(42,223)	(78.2)%
Accretion expenses	226	205	21	10.2%	452	412	40	9.7%
Total operating expenses	17,949	40,336	(22,387)	(55.5)%	37,111	82,928	(45,817)	(55.2)%
Other expenses (income):								
Interest expense	2,691	3,275	(584)	(17.8)%	5,214	6,814	(1,600)	(23.5)%
Interest expense-(Gain)/loss from mark-to-market activities	505	113	392	346.9%	(165)	630	(795)	(126.2)%
Interest income		(1)	1	(100.0)%	(1)	(1)		0.0%
Other (income) expense	(68)	(102)	34	(33.3)%	(126)	(290)	164	(56.6)%
Total other expenses (income)	3,128	3,285	(157)	(4.8)%	4,922	7,153	(2,231)	(31.2)%
Total expenses	21,077	43,621	(22,544)	(51.7)%	42,033	90,081	(48,048)	(53.3)%
Net income (loss)	$ 3,347	$ (21,092)	$ 24,439	(115.9)%	$ (1,805)	$ (3,034)	$ 1,229	(40.5)%
Net production:								
Natural gas production (MMcf)	3,417	3,647	(230)	(6.3)%	6,693	7,421	(728)	(9.8)%
Oil and liquids production (MBbl)	21	15	6	40.0%	46	29	17	58.6%
Total production (MMcfe)	3,545	3,745	(200)	(5.3)%	6,969	7,605	(636)	(8.4)%
Average daily production (Mcfe/d)	38,956	41,154	(2,198)	(5.3)%	38,503	42,017	(3,514)	(8.4)%
Average sales prices:								
Natural gas price per Mcf with hedge settlements	$ 19.10	$ 7.09	$ 12.01	169.4%	$ 13.31	$ 7.28	$ 6.03	82.8%
Natural gas price per Mcf without hedge settlements	$ 4.10	$ 3.96	$ 0.14	3.5%	$ 4.08	$ 4.71	$ (0.63)	(13.4)%
Oil and liquids price per Bbl without hedge settlements	$ 134.62	$ 81.73	$ 52.89	64.7%	$ 106.67	$ 79.24	$ 27.43	34.6%

Total price per Mcfe with hedge settlements	$	19.20	$	7.23	$	11.97	165.6%	$	13.49	$	7.40	$	6.09	82.3%
Total price per Mcfe without hedge settlements	$	4.75	$	4.18	$	0.57	13.6%	$	4.63	$	4.90	$	(0.27)	(5.5)%
Average unit costs per Mcfe:														
Field operating expenses[(a)]	$	2.05	$	2.24	$	(0.19)	(8.5)%	$	2.22	$	2.30	$	(0.08)	(3.5)%
Lease operating expenses	$	1.86	$	2.06	$	(0.20)	(9.7)%	$	2.01	$	2.06	$	(0.05)	(2.4)%
Production taxes	$	0.19	$	0.18	$	0.01	5.6%	$	0.21	$	0.24	$	(0.03)	(12.5)%
General and administrative	$	1.13	$	1.12	$	0.01	0.9%	$	1.18	$	1.22	$	(0.04)	(3.3)%
General and administrative w/o unit-based compensation	$	1.05	$	0.97	$	0.08	8.2%	$	1.09	$	1.09	$	0.00	0.0%
Depreciation, depletion and amortization	$	1.66	$	7.14	$	(5.48)	(76.8)%	$	1.69	$	7.10	$	(5.41)	(76.2)%

(a) Field operating expenses include lease operating expenses (average production costs) and production taxes.

Three months ended June 30, 2011 compared to three months ended June 30, 2010

Oil and natural gas sales. Oil and natural gas sales increased $41.0 million, or 151.4%, to $68.1 million for the three months ended June 30, 2011 as compared to $27.1 million for the same period in 2010. Of this increase, $39.8 million was attributable to our hedge program, $2.0 million was attributable to higher market prices for our oil and natural gas production, partially offset by $0.8 million attributable to decreased production volumes. Production for the three months ended June 30, 2011 was 3.5 Bcfe, which was 0.2 Bcfe lower than the same period in 2010. Of the decrease, 0.2 Bcfe was associated with our natural gas properties in the Cherokee Basin, partially offset by increased oil production from our recently acquired properties in the Central Kansas Uplift and our drilling programs in the Cherokee Basin. Production from our Black Warrior Basin and Woodford Shale properties remained approximately level. Our second quarter 2011 production was negatively impacted by a tornado in Alabama. Also, due to the decrease in the level of our total drilling activities during the past two years, our maintenance drilling programs have not been sufficient to offset the natural decline rate of production associated with our existing wells. We hedged approximately 73% of our actual production during 2011 and approximately 82% of our actual production during the same period in 2010.

As discussed below, the gain from our unrealized non-cash mark-to-market activities decreased $39.1 million for the three months ended June 30, 2011, as compared to the same period in 2010. Our realized prices before our hedging program increased from 2010 to 2011 primarily due to net higher market prices for our oil and natural gas production. The revenues that we generated from selling our products at realized market prices were offset by our hedging program and the mark-to-market losses discussed below.

Hedging and mark-to-market activities. As of June 30, 2011, all of our derivatives are accounted for as mark-to-market activities. For the three months ended June 30, 2011, the unrealized non-cash mark-to-market loss was approximately $43.7 million as compared to an unrealized non-cash $4.5 million loss for the same period in 2010. This 2011 non-cash loss represents approximately $43.2 million from the impact of our decision to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production from January 2012 through 2014 and higher than expected future oil and natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities, and by a $0.5 million increase for non-performance risk related to our counterparties.

Cash hedge settlements received for our natural gas commodity derivatives were approximately $51.2 million for the three months ended June 30, 2011. Cash hedge settlements received for our natural gas commodity derivatives were approximately $11.4 million for the three months ended June 30, 2010. This difference is primarily due to our decision to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production from January 2012 through 2014. In conjunction with the transaction, we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million. The remainder of the difference is due to higher market prices for natural gas and lower hedged volumes during 2011. We expect to begin receiving cash hedge settlements for our oil commodity derivatives in the third quarter 2011.

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 three months ended June 30, 2011, lease operating expenses decreased $1.1 million, or 14.6%, to $6.6 million, compared to expenses of $7.7 million for the same period in 2010. This decrease in lease operating expenses is primarily related to $1.1 million in lower expenses in the Cherokee Basin where our operations team has worked to lower costs by reducing compression expenses and controlling variable maintenance expenses. By category, our lease operating expenses were lower in 2011 as compared to 2010 because of $0.8 million in lower gas compression, $0.2 million in lower road and lease maintenance, and $0.1 million in lower well servicing.

For the three months ended June 30, 2011, per unit lease operating expenses were $1.86 per Mcfe compared to $2.06 per Mcfe for the same period in 2010. This decrease is attributable to 5.3% lower production in 2011 as compared to the same period in 2010 and the impact of a decrease in total spending of 14.6% in 2011 as compared to the same period in 2010. Our per unit operating costs decreased in the Cherokee Basin from $2.32 per Mcfe in 2010 to $2.02 per Mcfe in 2011 as a result of 0.2 Bcfe in lower production volumes and the impact of lower total spending. Additionally, during 2011 we were temporarily impacted by lower production volumes and increased operating costs from weather-related maintenance and repairs.

For the three months ended June 30, 2011, production taxes decreased less than $0.1 million, or 2.5%, to $0.7 million, compared to production taxes of $0.7 million for the same period in 2010. This slight decrease was primarily the result of the impact of production taxes on 0.2 Bcfe in lower production offset by the impact of higher market prices for oil and natural gas in 2011. We also recorded approximately $0.1 million in Oklahoma production tax credits during 2011.

Cost of sales. For the three months ended June 30, 2011, cost of sales decreased less than $0.1 million, or 7.4%, to $0.5 million, compared to $0.6 million for the same period in 2010. This represents the cost of purchased natural gas in the Cherokee Basin and was impacted by lower production volumes and higher market prices for natural gas, as these costs are tied to natural gas prices in the Mid-continent region.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, and other costs not directly associated with field operations.

General and administrative expenses decreased $0.2 million, or 4.2%, to $4.0 million for the three months ended June 30, 2011, as compared to $4.2 million for the same period in 2010. Our general and administrative expenses were lower in 2011 as compared to 2010 because of $0.3 million in lower non-cash unit-based compensation expenses offset by approximately $0.1 million in non-cash accruals for our unit-based award program.

Our per unit costs were $1.13 per Mcfe for the three months ended June 30, 2011 compared to $1.12 per Mcfe for the same period in 2010. This increase is attributable to 0.2 Bcfe in lower production offset by the impact of lower total spending of approximately $0.2 million.

Exploration Costs. Exploration costs decreased $0.2 million to nothing, or 100.0%, for the three months ended June 30, 2011, as compared to $0.2 million for the same period in 2010. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on our unproved properties. The decrease in 2011 is primarily as the result of $0.2 million in lower lease abandonments in Kansas and lower exploration costs in 2011 due to the impairment of certain unproved properties in the third quarter of 2010 because of lower expected future natural gas prices.

Gain/loss on sale of asset. Our gain/loss on the sale of assets increased $0.02 million, or 380.0%, to less than a $0.02 million loss for the three months ended June 30, 2011, as compared to a gain of less than $0.01 million for the same period in 2010. In 2011, we sold surplus equipment in Oklahoma for proceeds of less than $0.04 million, which exceeded the book value of the assets.

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

Our depreciation, depletion and amortization expense for the three months ended June 30, 2011 was $5.9 million, or $1.66 per Mcfe, compared to $26.7 million, or $7.14 per Mcfe, for the same period in 2010. This decrease in 2011 depreciation, depletion, and amortization largely reflects the decreased basis in our assets resulting from our 2010 impairments of our oil and natural gas properties, as well as an increase in our reserve base primarily due to price-related reserve revisions, higher capital expenditures for our development drilling programs, the acquisition of additional oil properties in the Central Kansas Uplift in December 2010, and a 0.2 Bcfe decrease in production volumes during 2011 as compared to 2010. We calculate depletion using units-of-production under the successful efforts method of accounting. Our other assets are depreciated using the straight line basis. Consistent with our prior practice, we will use our 2010 reserve report to calculate our depletion rate during the first three quarters of 2011. We expect our average depletion rate during the first three quarters of 2011 to be approximately $1.75 per Mcfe, which reflects our acquisition of our oil properties in the Central Kansas Uplift. We will use our 2011 reserve report to record our depletion in the fourth quarter of 2011.

Interest expense. Interest expense for the three months ended June 30, 2011 decreased $0.2 million to $3.2 million as compared to $3.4 million in interest expense for the same period in 2010. This decrease was primarily due to $0.4 million in higher non-cash mark-to-market losses on our interest rate swaps that are accounted for as mark-to-market activities, lower interest rate swap settlements of $0.5 million and lower amortization of debt issue costs of $0.1 million, while capitalized interest essentially remained level during 2011 as compared to the same period in 2010. At June 30, 2011, we had an outstanding balance under our reserve-based credit facility of $115.5 million as compared to $180.0 million at June 30, 2010. Since the third quarter of 2009, we used our excess operating cash flow to reduce our total debt from a high of $220.0 million to $109.25 million as of August 5, 2011. The average interest rate on our outstanding debt was approximately 5.4% in 2011 compared to 5.8% in 2010.

Interest income. Interest income for the three months ended June 30, 2011, was less than $0.01 million as compared to less than $0.01 million in interest income for same period in 2010. During 2011, market rates for overnight investments continued to be at historical lows, resulting in no significant earnings on our cash balances.

Accumulated other comprehensive income (loss). Accumulated other comprehensive income (loss), shown on our consolidated balance sheets, reflected the fair market value of certain of our previously designated cash-flow hedge positions. At June 30, 2011, the balance was an unrealized gain of $8.3 million compared to an unrealized gain of $10.9 million at December 31, 2010. This decrease reflects the amortization to earnings for the derivative positions that were previously accounted for as cash flow hedges that have cash settled during the second quarter of 2011.

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 $1.9 million for the three months ended June 30, 2011, and as an unrealized loss of $4.3 million for the same period in 2010. This change reflects the settlements during 2011 related to amounts previously included in locked accumulated other comprehensive income associated with our hedging positions previously accounted for as cash flow hedges. All of our derivative positions are now accounted for as mark-to-market activities and the remaining balance in AOCI will be amortized to earnings as the positions settle in the future.

Six months ended June 30, 2011 compared to six months ended June 30, 2010

Oil and natural gas sales. Oil and natural gas sales increased $37.7 million, or 66.9%, to $94.0 million for the six months ended June 30, 2011 as compared to $56.3 million for the same period in 2010. Of this increase, $42.7 million was attributable to our hedging program, offset by $3.1 million attributable to decreased production volumes and $1.9 million in lower net market prices for oil and natural gas. Production for the six months ended June 30, 2011 was 7.0 Bcfe, which was 0.6 Bcfe lower than the same period in 2010. Of the decrease, 0.7 Bcfe was a reduction of natural gas production due to our suspension of our drilling programs in the Cherokee Basin starting in June 2009, offset by an increase in production of 0.1 Bcfe associated with our oil production in the Cherokee Basin. Due to the decrease in the level of our drilling activities, our 2010 and 2011 maintenance drilling programs have not been sufficient to offset the natural decline rate of production associated with our existing wells. We hedged approximately 74% of our actual production during 2011 and approximately 81% of our actual production during the same period in 2010.

As discussed below, the gain from our unrealized non-cash mark-to-market activities decreased $84.5 million for the six months ended June 30, 2011, as compared to the same period in 2010. Our realized market prices before our hedging program decreased from 2010 to 2011 primarily due to lower market prices for natural gas, slightly offset by the impact of higher market prices for oil. The revenues that we generated from selling our products at realized market prices were offset by the impact of our hedging program and the associated mark-to-market gains and losses discussed below.

Hedging and mark-to-market activities. As of June 30, 2011, all of our swaps and basis swaps are accounted for as mark-to-market derivatives. For the six months ended June 30, 2011, the unrealized non-cash mark-to-market loss was approximately $53.7 million as compared to an unrealized non-cash $30.7 million gain for the same period in 2010. This 2011 non-cash loss represents approximately $53.6 million from the impact of our decision to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production beginning in January 2012 through 2014 and higher than expected future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities offset by decreased future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities, and by a $0.1 million increase for non-performance risk related to our counterparties. This 2010 non-cash gain represents approximately $32.3 million from the impact of decreased future natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities offset by a $1.6 million reduction for non-performance risk related to our counterparties.

Cash hedge settlements received for our commodity derivatives were approximately $61.8 million for the six months ended June 30, 2011. Cash hedge settlements received for our commodity derivatives were approximately $19.0 million for the six months ended June 30, 2010. This difference is primarily due to our decision to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production beginning in January 2012 through 2014. In conjunction with the transaction, we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million. The remainder of the difference is due to lower market prices for natural gas and lower hedged volumes during 2011.

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, 2011, lease operating expenses decreased $1.7 million, or 10.6%, to $14.0 million, compared to expenses of $15.7 million for the same period in 2010. This decrease in lease operating expenses is primarily related to $1.6 million in lower total spending in the Cherokee Basin and $0.1 million in lower expenses associated with our Black Warrior Basin properties. Our spending in the Woodford Shale properties during 2011 remained level with our spending in 2010. By category, our lease operating expenses were lower in 2011 as compared to 2010 because of $0.9 million in lower gas compression, $0.3 million in lower road and lease maintenance, $0.3 million in lower well servicing and repairs, $0.2 million in lower labor and benefits costs, and $0.1 million in lower salt water disposal costs, offset by $0.1 million in higher expenses for our non-operated properties.

For the six months ended June 30, 2011, per unit lease operating expenses were $2.01 per Mcfe compared to $2.06 per Mcfe for the same period in 2010. This decrease is attributable to a decrease in total spending of 10.6% in 2011 as compared to the same period in 2010 offset by the impact of 8.4% lower production in 2011 as compared to the same period in 2010. Our per unit operating costs decreased in the Cherokee Basin from $2.31 per Mcfe in 2010 to $2.27 per Mcfe in 2011 as a result of 0.6 Bcfe in lower production volumes and the impact of lower total spending. Our production decline in the Cherokee Basin is the result of lower maintenance capital expenditures in 2011 and 2010.

For the six months ended June 30, 2011, production taxes decreased $0.4 million, or 20.6%, to $1.4 million, compared to production taxes of $1.8 million for the same period in 2010. This decrease was primarily the result of the impact of production taxes on 0.6 Bcfe in lower production and lower net market prices for oil and natural gas in 2011. We also recorded approximately $0.1 million more in Oklahoma production tax credits during 2011 as compared to 2010.

Cost of sales. For the six months ended June 30, 2011, cost of sales decreased by approximately $0.2 million, or 21.8%, to $1.1 million, compared to $1.3 million for the same period in 2010. This represents the cost of purchased natural gas in the Cherokee Basin and was impacted by lower production volumes and lower market prices for natural gas, as these costs are tied to natural gas prices in the Mid-continent region.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, and other costs not directly associated with field operations.

General and administrative expenses decreased $1.0 million, or 11.0%, to $8.2 million for the six months ended June 30, 2011, as compared to $9.2 million for the same period in 2010. Our general and administrative expenses were lower in 2011 as compared to 2010 because of $0.4 million in lower consulting and audit fees, $0.3 million in lower non-cash unit-based compensation expenses, $0.2 million in lower labor expenses due to a lower headcount, and $0.1 million in lower insurance expenses.

Our per unit costs were $1.18 per Mcfe for the six months ended June 30, 2011 compared to $1.22 per Mcfe for the same period in 2010. This decrease is attributable to lower total spending of approximately $1.0 million and 0.6 Bcfe in lower production. Our total general and administrative expenses paid in cash remained level with the prior year.

Exploration Costs. Exploration costs decreased $0.3 million, or 70.7%, to $0.1 million for the six months ended June 30, 2011, as compared to $0.4 million for the same period in 2010. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment costs associated with leases on our unproved properties. The decrease in 2011 is primarily as the result of $0.2 million in lower lease abandonments in Kansas and lower exploration costs in 2011 due to the impairment of certain unproved properties in the third quarter of 2010 because of lower expected future natural gas prices, offset by one dry hole costing $0.1 million in 2011.

Gain/loss on sale of assets. Our gain/loss on the sale of assets increased $0.03 million, or 261.5%, to $0.02 million loss for the six months ended June 30, 2011, as compared to a gain of $0.01 million for the same period in 2010. In 2011, we sold surplus equipment at a loss of $0.02 million because our cash proceeds were slightly less than the net book value of the divested equipment.

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

Our depreciation, depletion and amortization expense for the six months ended June 30, 2011 was $11.8 million, or $1.69 per Mcfe, compared to $54.0 million, or $7.10 per Mcfe, for the same period in 2010. This decrease in 2011 depreciation, depletion, and amortization largely reflects the decreased basis in our assets resulting from our 2010 impairments of our oil and natural gas properties, as well as an increase in our year-end 2010 reserve base primarily due to price-related reserve revisions, higher capital expenditures for our development drilling programs, and a 0.6 Bcfe decrease in production volumes during 2011 as compared to 2010. We calculate depletion using units-of-production under the successful efforts method of accounting. Our other assets are depreciated using the straight line basis. Consistent with our prior practice, we will use our 2010 reserve report to calculate our depletion rate during the first three quarters of 2011. We expect our depletion rate during the first three quarters of 2011 to be approximately $1.75 per Mcfe. We will use our 2011 reserve report to record our depletion in the fourth quarter of 2011.

Interest expense. Interest expense for the six months ended June 30, 2011 decreased $2.4 million, or 32.2%, to $5.0 million as compared to $7.4 million in interest expense for same period in 2010. This decrease was primarily due to $0.8 million in lower non-cash mark-to-market losses on our interest rate swaps that are accounted for as mark-to-market activities, lower interest rate swap settlements of $1.2 million, and lower market interest rates resulting in lower interest expense of $0.4 million during 2011 as compared to the same period in 2010. At June 30, 2011, we had an outstanding balance under our reserve-based credit facility of $115.5 million as compared to $180.0 million at June 30, 2010. Since the third quarter of 2009, we used our excess operating cash flow to reduce our total debt from a high of $220.0 million to $109.25 million as of August 5, 2011. The average interest rate on our outstanding debt was approximately 5.4% in 2011 compared to 5.8% in 2010.

Interest income. Interest income for the six months ended June 30, 2011 was less than $0.01 million as compared to less than $0.01 million in interest income for same period in 2010. During 2011, market rates for overnight investments continued to be at historical lows, resulting in no significant earnings on our cash balances.

Accumulated other comprehensive income. Accumulated other comprehensive income, shown on our consolidated balance sheets, reflected the fair market value of certain of our previously designated cash-flow hedge positions. At June 30, 2011, the balance was an unrealized gain of $8.3 million compared to an unrealized gain of $10.9 million at December 31, 2010. This decrease reflects the amortization to earnings for the derivative positions that were previously accounted for as cash flow hedges that have cash settled during the first and second quarters of 2011.

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 $2.6 million for the six months ended June 30, 2011, and as an unrealized loss of $9.5 million for the same period in 2010. This decrease reflects the settlements during 2011 related to amounts previously included in locked accumulated other comprehensive income associated with our hedging positions previously accounted for as cash flow hedges. All of our derivative positions are now accounted for as mark-to-market activities and the remaining balance in AOCI will be amortized to earnings as the positions settle in the future.

Liquidity and Capital Resources

During 2010 and 2011, we utilized our cash flow from operations as our primary source of capital. Our primary use of capital during this time was for the retirement of outstanding debt, the development of existing oil and natural gas properties in the Cherokee Basin and the acquisition of non-operated oil properties in the Central Kansas Uplift.

Based upon our current business plan for 2011, we anticipate that we will continue to generate operating cash flows in excess of our working capital needs and planned capital expenditures. The primary focus of our business plan in 2011 will be to use our excess operating cash flows to further reduce our outstanding debt level. As we pursue our business plan, we will be monitoring the capital resources available to us to meet our future financial obligations and planned limited maintenance capital expenditures. Our current expectation is that we will manage our business to operate within the cash flows that are generated. Based on the initial progress of our 2011 drilling program, we sought and received authorization from our board of managers to increase our capital budget by an additional $2.0 million to further exploit oil potential in our asset base. We now forecast that our 2011 capital expenditures will range at the high end of between approximately $12.0 million and $14.0 million, of which $4.4 million had been paid as of June 30, 2011. Our current forecast for capital expenditures is expected to be lower than the $23.0 million in maintenance capital expenditures required to maintain our production levels in 2011. Because we reduced our maintenance capital expenditures in 2011, and also had reduced them in 2010, we expect lower production levels and lower operating cash flows in 2011. 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. We routinely monitor and adjust our capital expenditures and operating expenses in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, availability of funds under our reserve-based credit facility, and internally generated cash flow. Based upon current oil and natural gas price expectations, our existing hedge positions and expected production levels in 2011, we anticipate that our cash flow from operations in 2011 will decrease from 2010 levels. However, we expect that we will meet any planned capital expenditures and other cash requirements for the next twelve months without increasing our debt or issuing additional equity securities. During the remainder of 2011, we expect that our excess operating cash flows will continue to be used to reduce our outstanding debt level, which may provide us with additional liquidity from the available borrowing base under our reserve-based credit facility. However, future cash flows and our borrowing capacity are subject to a number of variables, including the level of oil and natural gas production and market prices for those products. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or operating expenses.

Our results will not be fully impacted by significant increases or decreases in oil and natural gas prices because of our hedging program. In the event of inflation increasing drilling and service costs, our hedging program will also limit our ability to have increased revenues recoup the higher costs, which could further impact our planned capital spending or operating expense levels. For 2011, we forecast total net production of between 13.4 Bcfe and 14.2 Bcfe. For the year, we have hedged approximately 74% of the midpoint of this forecast, including hedges for the remainder of 2011 on 3.5 Bcfe of our Mid-continent natural gas production at an average price, including basis, of $7.82 per Mcfe and an additional 1.3 Bcfe of our remaining natural gas production at a NYMEX-only price of $8.45 per Mcfe and 32 MBbl of our oil production at an average price of $110.10 per barrel. This hedge position locks in a significant portion of our expected operating cash flows for 2011 although we are still exposed to increases or decreases in oil and natural gas prices on our unhedged volumes.

During the remainder of 2011, we intend to continue to use any surplus operating cash flows to further reduce our debt level. Given our focus on debt reduction, we anticipate that quarterly distributions to our unitholders will remain suspended through the fourth quarter of 2011. We expect that the suspension of our quarterly distribution and maintaining our total planned capital expenditures below maintenance levels in 2011 will provide additional liquidity to fund our operations and to pay down debt. Since we first shifted our strategic focus to debt reduction, we have successfully reduced our outstanding debt balances from $220.0 million at the end of third quarter of 2009 to $109.25 million as of August 5, 2011. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. As of June 30, 2011, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions. We are subject to borrowing base redeterminations, which are scheduled to occur semi-annually or more frequently at the discretion of our lenders, and cannot forecast the level at which our lenders may set our borrowing base in the future. However, provided that our outstanding debt balance, net of available cash, is less than 90% of our borrowing base as determined by our lenders and at such time we are able to resume maintenance capital expenditures and have available cash, we will evaluate the resumption of our quarterly distribution to unitholders. This evaluation will consider our outstanding borrowings and cash reserves that are set by our board of managers for the proper conduct of our business. Any future quarterly distributions must be approved by our board of managers.

Our reserve-based credit facility currently provides a limited availability to finance future maintenance capital expenditures and other working capital needs. During the first six months of 2011, we did not borrow any daily short-term or any additional long-term amounts under our reserve-based credit facility. As of August 5, 2011, the borrowing base under our reserve-based credit facility was $140.0 million and we had $109.25 million of debt outstanding under the facility leaving us with $30.75 million in unused borrowing capacity. Our current reserve-based credit facility is subject to future borrowing base redeterminations and will have to be renewed or replaced before its maturity in November 2013. We expect to lower our outstanding debt levels by an additional $11.25 million to $16.25 million during the remainder of 2011, which would lower our outstanding debt to below $100.0 million. Our reserve-based credit facility is discussed below in further detail.

In the first quarter of 2011, we filed a new shelf registration statement with the SEC to register up to $500 million of debt or equity securities to repay or refinance outstanding debt and to fund working capital, capital expenditures and acquisitions. This registration statement will expire in three years. There is no guarantee that securities can or will be issued under the registration statement or that conditions in the financial markets would be supportive of an issuance of such securities by us.

Reserve-based credit facility

On June 3, 2011, we executed a second amendment to our $350.0 million credit agreement with The Royal Bank of Scotland plc as administrative agent and a syndicate of lenders. The reserve-based credit facility matures on November 13, 2013. Borrowings under the reserve-based credit facility are secured by various mortgages of oil and natural gas properties that we and certain of our subsidiaries own as well as various security and pledge agreements among us and certain of our subsidiaries and the administrative agent. The current lenders and their percentage commitments in the reserve-based credit facility are The Royal Bank of Scotland plc (26.84%), BNP Paribas (21.95%), The Bank of Nova Scotia (21.95%), Societe Generale (14.63%), and ING Capital LLC (14.63%).

The amount available for borrowing at any one time under the reserve-based credit facility is limited to the borrowing base for our oil and natural gas properties. As of June 30, 2011, our borrowing base was $140.0 million. The borrowing base is redetermined semi-annually, and may be redetermined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, together with, among other things, the oil and natural gas prices prevailing at such time. Our next semi-annual borrowing base redetermination is scheduled during the fourth quarter of 2011. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders.

Borrowings under the reserve-based credit facility are available for acquisition, exploration, operation and maintenance of oil and natural gas properties, payment of expenses incurred in connection with the reserve-based credit facility, working capital and general limited liability company purposes. The reserve-based credit facility has a sub-limit of $20.0 million which may be used for the issuance of letters of credit. As of June 30, 2011, no letters of credit are outstanding.

At our election, interest for borrowings are determined by reference to (i) the London interbank rate, or LIBOR, plus an applicable margin between 2.50% and 3.50% per annum based on utilization or (ii) a domestic bank rate (ABR) plus an applicable margin between 1.50% and 2.50% per annum based on utilization plus (iii) a commitment fee of 0.50% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The reserve-based credit facility contains various covenants that limit, among other things, our ability and certain of our subsidiaries ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions.

In addition, we are required to maintain (i) a ratio of Total Net Debt (defined as Debt (generally indebtedness permitted to be incurred by us under the reserve-based credit facility) less Available Cash (generally, cash, cash equivalents, and cash reserves of the Company)) to Adjusted EBITDA (generally, for any period, the sum of consolidated net income for such period plus (minus) 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, exploration costs, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on derivatives and realized (gain) loss on cancelled derivatives, and other similar charges) of not more than 3.50 to 1.0; (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 and current maturities of debt (to the extent such payments are not past due), of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS 133 and SFAS 143 (including the current liabilities in respect of the termination of oil and natural gas and interest rate swaps). All financial covenants are calculated using our consolidated financial information.

The reserve-based 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 reserve-based credit facility and a change of control. If an event of default occurs, the lenders will be able to accelerate the maturity of the reserve-based credit facility and exercise other rights and remedies. The reserve-based credit facility contains a condition to borrowing and a representation that no material adverse effect (MAE) has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a MAE were to occur, we would be prohibited from borrowing under the reserve-based credit facility and would be in default, which could cause all of our existing indebtedness to become immediately due and payable.

We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the reserve-based credit facility, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the reserve-based credit facility exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by our board of managers for the proper conduct of our business and the payment of fees and expenses. As of August 5, 2011, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions.

The reserve-based credit facility permits us to hedge our projected monthly production, provided that (a) for the immediately ensuing twelve month period, the volumes of production hedged in any month may not exceed our reasonable business judgment of the production for such month consistent with the application of petroleum engineering methodologies for estimating proved developed producing reserves based on the then-current strip pricing (provided that such projection shall not be more than 115% of the proved developed producing reserves forecast for the same period derived from the most recent reserve report of our petroleum engineers using the then strip pricing), and (b) for the period beyond twelve months, the volumes of production hedged in any month may not exceed the reasonably anticipated projected production from proved developed producing reserves estimated by our petroleum engineers. The reserve-based credit facility also permits us to hedge the interest rate on up to 90% of the then-outstanding principal amounts of our indebtedness for borrowed money.

The reserve-based credit facility contains no covenants related to our relationship with Constellation or Constellation s right to appoint all of the Class A managers of our board of managers.

At June 30, 2011, we believe that we were in compliance with the financial covenants contained in our reserve-based credit facility. We monitor compliance on an ongoing basis. As of June 30, 2011, our actual Total Net Debt to annual Adjusted EBITDA ratio was 1.9 to 1.0 as compared with a required ratio of not greater than 3.5 to 1.0, our actual ratio of consolidated current assets to consolidated current liabilities was 4.6 to 1.0 as compared with a required ratio of not less than 1.0 to 1.0, and our actual quarterly Adjusted EBITDA to cash interest expense ratio was 10.2 to 1.0 as compared with a required ratio of not less than 2.5 to 1.0.

If we are unable to remain in compliance with the debt covenants associated with our reserve-based credit facility or maintain the required ratios discussed above, we could request waivers from the lenders in our bank group. Although the lenders may not provide a waiver, we could take additional steps in the event of not meeting the required ratios or in the event of a reduction in the borrowing base below as determined by the lenders. During 2011, we intend to use our surplus operating cash flows to reduce our outstanding debt. If it becomes necessary to reduce debt by amounts that exceed our operating cash flows, we could further reduce capital expenditures, continue to suspend our quarterly distributions to unitholders, sell oil and natural gas properties, liquidate in-the-money derivative positions, further reduce operating and administrative costs, or take additional steps to increase liquidity. If we become unable to obtain a waiver and were unsuccessful at reducing our debt to the necessary level, our debt could become due and payable upon acceleration by the lenders. To the extent that we do not enter into an agreement to refinance or extend the due date on the reserve-based credit facility, the outstanding debt balance at November 13, 2012, will become a current liability.

We have hedging arrangements to reduce the impact of changes in the LIBOR interest rate on our interest payments for $93.0 million of the $109.25 million outstanding on our reserve-based credit facility at August 5, 2011. These positions are outlined in Item 3. Quantitative and Qualitative Disclosures About Market Risk Interest Rate Risk.

Cash Flow from Operations

Our net cash flow provided by operating activities for the six months ended June 30, 2011 was $60.1 million, compared to net cash flow provided by operating activities of $19.3 million for the same period in 2010. This increase in operating cash flow was primarily attributable to lower operating expenses as a result of $2.4 million in lower total spending in both administrative and lease operating expenses, the impact of our acquisition of oil properties in the Central Kansas Uplift, and the impact of higher oil and natural gas sales of $37.7 million. We had 0.6 Bcfe in lower natural gas production in 2011, which lowered our operating cash flows. During 2011, our operating cash flows were increased by $60.7 million related to cash hedge settlements for our oil and natural gas commodity and interest rate derivatives. This increase was primarily a result of us executing a one-time transaction to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production beginning in January 2012 through 2014. In conjunction with the transaction, we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million, which was used, together with cash on hand, to reduce our outstanding debt balance under our reserve-based credit facility by $42.0 million.

Our change in working capital of $5.4 million from 2010 to 2011 was impacted by lower accrued liabilities of $3.7 million, lower accounts payable of $0.2 million, higher royalties payable of $0.2 million, higher accounts receivable of $0.8 million and lower prepaid expenses of $0.1 million. Our accrued liabilities decreased with the payments associated with our 2010 incentive compensation programs and with the payment of $1.2 million to settle the Torch NPI litigation. We also used $1.0 million to fund an escrow account for a deposit associated with our offer to purchase the NPI that was part of the settlement. This escrow is included in our consolidated balance sheet as an other current asset. Our accounts payable decreased due to timing of invoice payments. Our receivables balance and our royalties payable balance both increased due to the impact of higher oil prices offset by lower natural gas prices and lower production volumes for our estimated natural gas sales due to weather-related decreases in production during 2011. The decrease in prepaid expenses of $0.1 million primarily resulted from the timing of the payment for insurance expenses.

Our cash flow from operations is subject to many variables, the most significant of which are the volatility of oil and natural gas prices and our level of production of oil and natural gas. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our

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control. Our future cash flow from operations will depend on our ability to maintain and increase production through our development program or completing acquisitions, as well as the market prices of oil and natural gas and our hedging program. For additional information on our business plan, refer to Outlook .

Open Commodity Hedge Positions

We enter into hedging arrangements to reduce the impact of oil and natural gas price volatility on our operations. By removing the price volatility from a significant portion of our oil and 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 the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to fund higher severance taxes, which are usually based on market prices for oil and 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 fund these higher costs. Increases in the market prices for oil and natural gas will also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to our derivative contracts is a lender in our reserve-based credit facility and we do not post collateral with our counterparties under any of these agreements. This is significant since we are able to lock in attractive sales prices on a substantial amount of our expected future production without posting cash collateral based on price changes prior to the hedges being cash settled.

The following tables summarize, for the periods indicated, our hedges currently in place through December 31, 2015. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps NYMEX (Henry Hub)

	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
2011.					2,220,000	$ 8.45	2,220,000	$ 8.45	4,440,000	$ 8.45
2012.	2,227,500	$ 5.75	2,227,500	$ 5.75	2,250,000	$ 5.75	2,250,000	$ 5.75	8,955,000	$ 5.75
2013.	2,025,000	$ 5.75	2,079,500	$ 5.75	2,070,000	$ 5.75	2,038,000	$ 5.75	8,212,500	$ 5.75
2014.	1,575,000	$ 5.75	1,592,500	$ 5.75	1,610,000	$ 5.75	1,610,000	$ 5.75	6,387,500	$ 5.75
									27,995,000	

MTM Fixed Price Swaps CenterPoint Energy Gas Transmission (East)

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2011					180,000	$ 7.93	180,000	$ 7.93	360,000	$ 7.93
									360,000	

MTM Fixed Price Basis Swaps CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), or Southern Star Central Gas Pipeline (Texas, Oklahoma, and Kansas)

	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 $
2011					1,703,467	$ 0.62	1,393,700	$ 0.68	3,097,167	$ 0.65
2012	1,502,800	$ 0.58	1,427,100	$ 0.59	1,352,900	$ 0.61	1,295,900	$ 0.62	5,578,700	$ 0.60
2013	1,245,400	$ 0.40	1,192,900	$ 0.40	1,145,700	$ 0.40	1,104,400	$ 0.40	4,688,400	$ 0.40
2014	1,053,465	$ 0.40	1,010,529	$ 0.40	971,508	$ 0.40	939,067	$ 0.40	3,974,569	$ 0.40
									17,338,836	

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MTM Fixed Price Basis Swaps West Texas Intermediate (WTI)

	For the quarter ended (in Bbls)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2011					16,545	$ 110.10	15,278	$ 110.10	31,823	$ 110.10
2012	14,183	$ 108.00	13,262	$ 108.00	12,520	$ 108.00	11,881	$ 108.00	51,846	$ 108.00
2013	11,298	$ 104.32	10,720	$ 104.32	10,197	$ 104.32	9,743	$ 104.32	41,958	$ 104.32
2014	9,317	$ 102.25	8,959	$ 102.25	8,652	$ 102.25	8,367	$ 102.25	35,295	$ 102.25
2015	8,095	$ 101.10	7,834	$ 101.10	7,588	$ 101.10	7,326	$ 101.10	30,843	$ 101.10
									191,765	

All of our derivatives were accounted for as mark-to-market activities as of June 30, 2011. The net risk management asset for our commodity and interest rate derivatives was $27.2 million at June 30, 2011, as compared to a net risk management asset of $83.4 million at December 31, 2010. These values represent the fair value of our derivative positions at those respective dates. This value has declined from 2010 to 2011 primarily because of a one-time cash payment from our derivative counterparties of $41.3 million as a result of our NYMEX hedge restructuring, cash settlements on 2011 derivative positions of $19.4 million, and the change in the non-performance risk related to our counterparties of $0.2 million, offset by the impact of expected future market prices for natural gas and interest rates of $3.6 million, and the addition of oil derivative positions of $1.1 million. As a result of resetting the NYMEX fixed-to-floating price to $5.75 per MMBtu for our NYMEX swap agreements from January 2012 through December 2014, we would expect that our operating cash flows and reported Adjusted EBITDA will now be lower during that time. This is because of the expected decrease in the value of future cash hedge settlements on the reset NYMEX positions. We believe the expected lower operating cash flows and Adjusted EBITDA should not impact our future ability to comply with the financial covenant ratios contained in our reserve-based credit facility because we have reduced the amount of our outstanding debt.

Investing Activities Acquisitions and Capital Expenditures

Cash used in investing activities was $4.1 million for the six months ended June 30, 2011, compared to $2.6 million for the same period in 2010. Our cash capital expenditures were $4.4 million in 2011, which primarily consisted of development expenditures in the Cherokee Basin and in the Black Warrior Basin. During the first half of 2011, we have completed 10 net wells and 24 net recompletions in the Cherokee Basin and 5 net wells in the Black Warrior Basin. We had 2 net wells in progress and 14 net recompletions in progress at the end of the quarter. One of the wells in progress is in the Black Warrior Basin and 1 of the wells is in the Central Kansas Uplift. We also received $0.3 million in post-closing adjustments related to our acquisition of oil properties in the Central Kansas Uplift and received $0.2 million in distributions from an equity affiliate.

Our capital expenditures were $2.8 million for the six months ended June 30, 2010, of which $2.3 million related to drilling expenditures for our 2010 capital program in the Cherokee Basin and $0.5 million related to the acquisition of additional interests in seven natural gas wells in the Cherokee Basin and in the Black Warrior Basin.

The current 2011 capital budget of $12.0 million to $14.0 million is expected to be below our 2011 estimated maintenance capital level of $23.0 million and our 2010 estimated maintenance capital level of $25.3 million. We expect that our current and future capital expenditures will continue to be funded using our cash flow from operations. We believe this decreased level of maintenance capital spending will result in lower production volumes in 2011. Once market conditions warrant, we expect to evaluate the resumption of capital spending at a level sufficient to maintain our then current production rate. Given the current proportion of natural gas relative to oil in our asset base, we believe that natural gas prices in excess of $6.00 per Mcfe produce rates of return that generally support capital spending at maintenance levels.

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, and the borrowing base under our reserve-based credit facility is further reduced, drilling costs escalate, or our efforts to exploit oil potential in our asset base prove to be unsuccessful, we could choose to defer a portion of these planned capital expenditures until later periods. We routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, availability of funds under our reserve-based credit facility, 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 oil and 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 facility will meet any planned capital expenditures and other cash requirements for the next twelve months. In 2011, we expect that our excess operating cash flows will be used to reduce our outstanding debt level. However, future cash flows are subject to a number of variables, including the level of oil and 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 further impact our planned capital spending.

Financing Activities

Our net cash used in financing activities was $50.5 million for the six months ended June 30, 2011, compared to $15.4 million used in financing activities for the same period in 2010. During 2011, we used $49.5 million in operating cash flows to reduce our outstanding debt level, including $41.3 million in cash proceeds received when we executed a transaction to reset our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production beginning in January 2012 through 2014. Through August 5, 2011, we reduced our outstanding debt in 2011 from $165.0 million to $109.25 million, or by 33.8%. We also used $0.3 million to fund the cost of units tendered by employees for tax withholdings for unit-based compensation and $0.6 million in additional debt issue costs associated with the second amendment to our reserve-based credit facility. At June 30, 2011, we had approximately $3.0 million in debt issue costs remaining to be amortized through November 2013.

We have suspended our $0.13 per unit quarterly distributions to unitholders since the quarter ended June 30, 2009, to reduce our outstanding indebtedness. Given our current focus on debt reduction, we anticipate that our distribution will remain suspended through the fourth quarter of 2011. Assuming that the quarterly distribution rate would have remained at $0.13 per unit for each quarter in 2011, this suspension of the quarterly distribution would provide approximately $12.9 million in cash flow during 2011 that could be used to reduce our outstanding debt balance under our reserve-based credit facility. For each of the quarterly periods since March 31, 2008, we have also suspended $4.3 million out of the $6.7 million in distributions on the Class D interests that have yet to be paid. We expect that these quarterly distributions on the Class D interests, and all future quarterly distributions on the Class D interests, will remain suspended until such time as distributions are permitted under our reserve-based credit facility and limited liability company agreement. For additional information, refer to Outlook .

Our net cash used in financing activities was $15.4 million for the six months ended June 30, 2010. During 2010, we used $15.0 million in operating cash flows to reduce our outstanding debt level from $195.0 million to $180.0 million or by 7.7%. At June 30, 2010, we had approximately $4.6 million in debt issue costs remaining to be amortized through November 2012.

Contractual Obligations

At June 30, 2011, we had the following contractual obligations or commercial commitments:

	Payments Due By Year(1)(2) (in thousands)					
	2011	**2012**	**2013**	**2014**	**Thereafter**	**Total**
Reserve-Based Credit Facility	$	$	$ 115,500	$	$	$ 115,500
Support Services Agreement	906					906
Offices Leases	416	424	408	422	752	2,422
Total	$ 1,322	$ 424	$ 115,908	$ 422	$752	$ 118,828

(1) This table does not include any liability associated with derivatives.
(2) This table does not include interest as interest rates are variable. The average interest rate on our outstanding debt was approximately 5.4% at June 30, 2011.

At June 30, 2011, our asset retirement obligation was approximately $13.5 million.

Off-Balance Sheet Arrangements

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

Credit Markets and Counterparty Risk

We actively monitor the credit exposure and risks associated with our counterparties. Additionally, we continue to monitor global credit markets to limit our potential exposure to credit risk where possible. Our primary credit exposures result from the sale of oil and natural gas and our use of derivatives. Through August 5, 2011, we have not suffered any losses with our counterparties as a result of nonperformance.

Certain key counterparty relationships are described below:

Macquarie Energy LLC

Macquarie Energy LLC (Macquarie), a subsidiary of Sydney, Australia-based Macquarie Group Limited, purchases a portion of our natural gas production in the Cherokee Basin. We have received a guarantee from Macquarie Bank Limited for up to $8.0 million in purchases through December 31, 2011. As of August 5, 2011, we have no past due receivables from Macquarie.

Scissortail Energy, LLC

Scissortail Energy, LLC (Scissortail), a subsidiary of Copano Energy, L.L.C., purchases a portion of our natural gas production in Oklahoma and Kansas. As of August 5, 2011, we have no past due receivables from Scissortail.

ONEOK Energy Services Company, L.P.

ONEOK Energy Services Company, L.P. (ONEOK), a subsidiary of ONEOK, Inc., purchases a portion of our natural gas production in Oklahoma and Kansas. We have received a guarantee from ONEOK, Inc. for up to $3.0 million in purchases through November 23, 2011. As of August 5, 2011, we have no past due receivables from ONEOK.

J.P. Morgan Ventures Energy Corporation

J.P. Morgan Ventures Energy Corporation purchases the majority of our natural gas production in Alabama. The payment for the purchases is guaranteed by JP Morgan Chase & Company through June 30, 2014. As of August 5, 2011, we have no past due receivables from J.P. Morgan Ventures Energy Corporation.

Derivative Counterparties

As of August 5, 2011, all of our derivatives are with BNP Paribas, The Royal Bank of Scotland plc, Societe Generale, The Bank of Nova Scotia, and ING Capital LLC. These banks are lenders who participate in our reserve-based credit facility. All of our derivatives are collateralized by the assets securing our reserve-based credit facility and therefore currently do not require the posting of cash collateral. As of August 5, 2011, each of these financial institutions has an investment grade credit rating but BNP Paribas, The Royal Bank of Scotland plc, Societe Generale are on review for a possible downgrade by Moody s Investor Service. However, it would take a multiple ratings downgrade for each of these banks to fall below investment grade.

Reserve-Based Credit Facility

As of August 5, 2011, the banks and their percentage commitments in our reserve-based credit facility are: The Royal Bank of Scotland plc (26.84%), BNP Paribas (21.95%), The Bank of Nova Scotia (21.95%), ING Capital LLC (14.63%), and Societe Generale (14.63%). As of August 5, 2011, each of these financial institutions has an investment grade credit rating.

Outlook

During 2011, 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.

Full Year 2011 Expected Results

Our 2011 business plan and forecast is focused on further reducing our outstanding debt level and promoting financial flexibility by limiting capital expenditures and an anticipated continued suspension of our quarterly distribution through the fourth quarter of 2011. We currently expect our operating environment to be characterized by continued low natural gas prices and increasing cost pressures, including higher service costs and healthcare costs.

For 2011, we currently anticipate:

- Our production to be between 13.4 Bcfe and 14.2 Bcfe, approximately 74% of which is currently hedged at prices that are attractive relative to the price levels we currently observe in the commodity markets.

- Our operating expenses to be actively managed, resulting in a range of $48.0 million to $52.0 million.

Continued success in the drilling of our oil prospects has lead us to seek authorization from our board of managers to increase our 2011 capital budget by an additional $2.0 million to further exploit oil potential in our asset base. We now expect our total capital expenditures to be at the high end of $12.0 million to $14.0 million, which assumes a decline rate of 15 percent and a dollar per flowing Mcfe range of $3,200 to $3,800. Despite this increase in our capital budget, it remains at a level below our estimated maintenance level of capital expenditures of $23.0 million for 2011 and $25.3 million for 2010. We now expect to drill and complete approximately 70 to 80 net wells and recompletions, both in the Black Warrior Basin and in the Cherokee Basin. We have very limited amounts of lease expirations during 2011 and 2012, which generally allows us to reduce our drilling activities without losing our undeveloped locations. We expect to actively review our drilling and recompletion opportunities and anticipate allocating capital to the highest value-added projects across all of our available opportunities.

Our operating cash flows to allow for an additional $11.25 million to $16.25 million reduction of our outstanding debt level at December 31, 2011, below our $115.5 million balance at June 30, 2011.

Our quarterly distributions to our unitholders to remain suspended through the fourth quarter of 2011. All future quarterly distributions must be approved by our board of managers.

Impact of 2011 Plan

Our 2011 operating plan is intended to further reduce our outstanding debt by continuing our reduction of capital expenditures and continuing the suspension of our quarterly distribution to unitholders. We expect that these plans will result in lower production levels in 2011. Our limited capital spending will likely result in lower production levels continuing into future periods. We do not believe, however, that during a period of limited capital expenditures, we would lose any significant leased acreage. These plans are expected to reduce our leverage, continue to improve our liquidity position, and reduce future cash interest expenses on our outstanding unhedged debt. When we forecast over the next five years, we currently expect that our existing asset base and hedge portfolio will allow us fund a limited capital program while substantially reducing our outstanding debt.

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 estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of our financial statements. Below, we have provided an expanded discussion of our more critical accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in the preparation of the consolidated financial statements.

As of June 30, 2011, there were no changes with regard to the critical accounting policies disclosed in our Annual Report on Form 10-K for the year ended December 31, 2010, which was filed on February 25, 2011. The policies disclosed included the accounting for oil and natural gas properties, oil and 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 and New Accounting Pronouncements Issued But Not Yet Adopted

The impact of new accounting pronouncements is further discussed in Note 3 to 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 oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Global Financial and Energy Markets

The U.S. economy has continued to improve but the level of improvement has been insufficient to materially increase the demand for natural gas, which accounts for a majority of our production. Concurrently, production from shale gas plays has increased the supply of natural gas in the U.S. and inventories of natural gas in storage remain at record high levels. As a result, future expected prices for natural gas remain depressed relative to the price levels observed at the time our assets were acquired. At the same time, oil prices have dramatically increased in part due to the impact of a lower U.S. dollar and unrest in the Middle East.

We expect that our ability to issue debt and equity securities may continue to be limited over the next year. We also anticipate that the borrowing base of our reserve-based credit facility could be further reduced, particularly if future expected market prices for natural gas prices remain depressed or decline further, thereby reducing our borrowing base. In response to the credit crisis and the decline in the market prices for natural gas, we have suspended our cash distribution since June 2009 and lowered our maintenance capital spending in 2009 and 2010, and currently intend to do so again in 2011. This lower maintenance capital spending will result in declining production which could lower our future operating cash flows. Because of the increase in oil prices, we expect to focus our limited capital spending on oil opportunities in our operating areas. If market prices for natural gas remain depressed or oil prices decrease, our future cash flows from operations will be reduced for our unhedged production. We continue to monitor the financial and energy markets to determine if we should further revise the timing and scope of our future drilling programs, financing activities, and acquisition activities to determine the impact of these activities on the reinstatement of our distributions to unitholders.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas production and to some extent our oil production. Realized pricing is primarily driven by the NYMEX (Henry Hub) and Inside FERC prices for Southern Natural Gas Company (Louisiana) with respect to our properties in the Black Warrior Basin and the Inside FERC prices for CenterPoint Energy Gas Transmission (East), Natural Gas Pipeline Company of America (Midcontinent), the CenterPoint Energy Gas Transmission (East), ONEOK Gas Transportation (Oklahoma), Panhandle Eastern Pipeline (Texas, Oklahoma) and Southern Star Central Gas Pipeline (Texas, Oklahoma, Kansas) with respect to our properties in the Cherokee Basin, the Inside FERC price for the CenterPoint Energy Gas Transmission (East) for our properties in the Woodford Shale, NYMEX West Texas Intermediate (Cushing, Oklahoma) for our oil production and the spot market prices applicable to all of our oil and natural gas production. Historically, pricing for oil and natural gas has been volatile and unpredictable and we expect this volatility to continue in the future. We are currently operating in an environment characterized by low natural gas prices which tends to lower the revenues that we realize on our unhedged natural gas production and limit the amount of operating cash flows available for maintenance capital expenditures, distributions to unitholders, or debt reduction. The prices we receive for oil and natural gas production depend on many factors outside our control, including weather, economic conditions, and the total supply of oil and natural gas available for sale in the market.

We have entered into hedging arrangements with respect to a portion of our projected future production through various derivatives that hedge the future prices received. These hedging activities are intended to support commodity sales prices at targeted levels and to manage our exposure to commodity price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes. The use of hedging transactions also involves the risk that one or more of the counterparties will be unable to meet the financial terms of the transactions executed. We attempt to minimize this risk by entering into our derivative transactions with counterparties that are lenders in our reserve-based credit facility. 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 oil and natural gas production, and as a result, we are subject to commodity price risks on our remaining unhedged oil and 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 at June 30, 2011	$ 30,582	$ 17,006	$ (13,576)	$ 44,158	$ 13,576

Interest Rate Risk

At June 30, 2011, the one-month LIBOR rate was 0.186%, the three-month LIBOR rate was 0.246%, and our applicable margin on LIBOR borrowings was 3.25%. At June 30, 2011, the ABR rate was 3.25%, and our applicable margin on ABR borrowings was 2.25%. At June 30, 2011, we had debt outstanding of $115.5 million. This amount incurred interest at various one-month and three-month LIBOR rates plus an applicable margin of 3.25% based on utilization. We had no debt outstanding at the ABR rates. At June 30, 2011, the carrying value and fair value of our debt is $115.5 million.

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

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	Fair Value	10 Percent Increase Fair Value	Increase (in 000 s)	10 Percent Decrease Fair Value	(Decrease)
Impact of changes in LIBOR on derivative interest rate instruments at June 30, 2011	$ (3,408)	$ (2,897)	$ 511	$ (3,919)	$ (511)

We enter into hedging arrangements to reduce the impact of volatility of changes in the LIBOR interest rate on our interest payments for $93.0 million of our outstanding debt balance of $109.25 million at August 5, 2011. If we reduce our outstanding debt balance to $93.0 million or lower, our cash interest costs for our effective LIBOR rate would begin to approximate the settlements on these interest rate swaps. At June 30, 2011, we have the following outstanding interest rate swaps that fix our LIBOR rate:

Maturity Date	Total Debt Hedged (in 000 s)	LIBOR Fixed Rate
August 20, 2014	$ 11,000	2.37%
September 20, 2014	$ 31,000	2.52%
October 19, 2014	$ 23,500	2.68%
October 22, 2014	$ 7,500	2.61%
November 20, 2014	$ 14,000	2.535%
November 20, 2014	$ 6,000	2.69%

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 six months ended June 30, 2011, 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

Litigation Related to Trust Termination

On January 8, 2009, we were served by Trust Venture, on behalf of the Trust, with a purported derivative action filed in the Circuit Court of Tuscaloosa County, Alabama (the Court). The lawsuit related to the non-operating NPI held by the Trust on certain wells owned by Robinson s Bend Production II, LLC (RBP II), a subsidiary of the Company, in the Robinson s Bend Field in Alabama, and alleged, among other things, a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserted that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit sought unspecified damages and an accounting of the NPI. The Court made the Trust a nominal party to the lawsuit. On February 4, 2011, the parties entered into a settlement agreement subject to approval by the Court. At a preliminary hearing on February 17, 2011, the Court approved a form of notice of a settlement among the parties to be sent by the Trust to its unitholders. On April 13, 2011, the Court approved the settlement and the effective date of the settlement was June 13, 2011. The settlement with Trust Venture, its successor and the Trust provided, among other things:

RBP II made a payment of $1.2 million to reimburse Trust Venture and its successor for their legal fees and expenses incurred in prosecuting the lawsuit;

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RBP II made an irrevocable offer to purchase the NPI relating to the Robinson s Bend Field from the Trust for at least $1 million, when it is separately offered for sale by the Trust at public auction within 180 days of the effective date of the settlement, with such bid amount to be deposited by RBP II in a third-party escrow account pending the public auction. RBP II, as well as any other bidders at the auction, shall have a right to submit a higher topping bid;

The parties agreed that the cumulative deficit balance in the NPI account is approximately $5.8 million as of September 30, 2010, and that no further payments will be due to the Trust with respect to the NPI unless and until the cumulative deficit balance is reduced to zero;

Trust Venture and its successor agreed, on behalf of the Trust, that all prior and current calculations, charges and deductions contained in such cumulative deficit NPI balance are in compliance with the terms of the Conveyance and, to the extent applicable thereunder, do not exceed competitive contract charges prevailing in the area for any such operations and services;

The Water Gathering and Disposal Agreement between RBP II and another subsidiary of the Company was amended to reduce the fee from $1.00 per barrel to $0.53 per barrel beginning on the first day of the month following the effective date of the settlement and to extend the term for an additional ten years, and Trust Venture and its successor agreed, on behalf of the Trust, that the fees under such agreement do not exceed competitive contract charges prevailing in the area for the operations and services provided under such agreement during the extended term of such agreement; and

A mutual release among the parties became effective and the lawsuit was dismissed with prejudice.

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in Item 1A. to Part I of our Annual Report on Form 10-K for the year ended December 31, 2010 that was filed on February 25, 2011. An investment in our Class B common units involves various risks. When considering an investment in us, careful consideration should be given to the risk factors described in our 2010 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.

Forward-Looking Statements

This Quarterly Report on Form 10-Q contains forward-looking statements as defined by the SEC that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about:

the volatility of realized oil and natural gas prices;

the conditions of the capital markets, inflation, interest rates, availability of credit facilities to support business requirements, liquidity, and general economic and political conditions;

the discovery, estimation, development and replacement of oil and natural gas reserves;

our business, financial, and operational strategy;

our drilling locations;

technology;

our cash flow, liquidity and financial position;

the ability to extend or refinance our reserve-based credit facility;

the level of our borrowing base under our reserve-based credit facility;

the resumption or amount of our cash distribution;

the impact from any termination of the NPI sharing arrangement or any change in the calculation of the NPI;

our hedging program and our derivative positions;

our production volumes;

our lease operating expenses, general and administrative costs and finding and development costs;

the availability of drilling and production equipment, labor and other services;

- our future operating results;
- our prospect development and property acquisitions;
- the marketing of oil and natural gas;
- competition in the oil and natural gas industry;
- the impact of the current global credit and economic environment;
- 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, including environmental regulation, and taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas producing countries;
- support from our former sponsor or a change in significant unitholders; and
- our strategic plans, objectives, expectations, forecasts, budgets, estimates and intentions for future operations.

All of these types of statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations and other items within this Quarterly Report on Form 10-Q. In some cases, forward-looking statements can be identified by terminology such as may, could, should, expect, plan, project, intend, anticipate, believe, estimate, predict, potential, the negative of such terms or other comparable terminology.

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

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Reserved

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 six months ended June 30, 2011 and June 30, 2010

Consolidated Balance Sheets Constellation Energy Partners LLC at June 30, 2011 and December 31, 2010

Consolidated Statements of Cash Flows Constellation Energy Partners LLC for the six months ended June 30, 2011 and June 30, 2010

Consolidated Statements of Changes in Members Equity Constellation Energy Partners LLC for the six months ended June 30, 2011

Notes to Consolidated Financial Statements

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EXHIBIT INDEX

Exhibit Number	Description
*10.1.	Form of Grant Agreement Relating to Unit-Based Awards Executives.
*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.
**101.INS	XRBL Instance Document
**101.SCH	XRBL Schema Document
**101.CAL	XRBL Calculation Linkbase Document
**101.LAB	XRBL Label Linkbase Document
**101.PRE	XRBL Presentation Linkbase Document
**101.DEF	XRBL Definition Linkbase Document

* Filed herewith
** Furnished herewith

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SIGNATURES

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

CONSTELLATION ENERGY PARTNERS LLC
(Registrant)

Date: August 5, 2011

By /s/ MICHAEL B. HINEY
Michael B. Hiney

Chief Accounting Officer and Controller

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