Constellation Energy Partners LLC
Form 10-Q
August 09, 2012
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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, 2012

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 9, 2012: 23,681,878 units.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

(Unaudited)

	June 30, 2012	December 31, 2011
	(In 000 s)	
ASSETS		
Current assets		
Cash	$ 7,095	$ 17,176
Accounts receivable	4,787	6,394
Prepaid expenses	1,420	1,243
Risk management assets (see Note 4)	21,020	20,283
Total current assets	34,322	45,096
Oil and natural gas properties (See Note 6)		
Oil and natural gas properties, equipment and facilities	792,627	787,322
Material and supplies	1,636	1,243
Less accumulated depreciation, depletion, amortization, and impairments	(530,831)	(522,480)
Net oil and natural gas properties	263,432	266,085
Other assets		
Debt issue costs (net of accumulated amortization of $7,111 at June 30, 2012 and $6,465 at December 31, 2011)	1,779	2,423
Risk management assets (see Note 4)	16,368	17,603
Other non-current assets	3,519	3,099
Total assets	$ 319,420	$ 334,306
LIABILITIES AND MEMBERS EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 1,051	$ 1,404
Accrued liabilities	7,223	10,638
Royalty payable	1,639	2,134
Risk management liabilities (see Note 4)		378
Total current liabilities	9,913	14,554
Other liabilities		
Asset retirement obligation	14,507	14,047
Risk management liabilities (see Note 4)	412	286
Other non-current liabilities	452	99
Debt	88,400	98,400
Total other liabilities	103,771	112,832
Total liabilities	113,684	127,386
Commitments and contingencies (See Note 8)		

Members equity		
Class A units, 483,531 and 485,033 units authorized, issued and outstanding, respectively	4,057	4,030
Class B units, 24,124,378 and 24,124,378 units authorized, respectively, and 23,693,018 and 23,766,632 issued and outstanding, respectively	198,799	197,453
Accumulated other comprehensive income	2,880	5,437
Total members equity	205,736	206,920
Total liabilities and members equity	$ 319,420	$ 334,306

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Income (Loss)

(Unaudited)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(In 000 s except unit data)			
Revenues				
Natural gas sales	$ 13,809	$ 65,253	$ 27,687	$ 89,086
Oil and liquids sales	2,900	2,827	6,180	4,907
Gain / (Loss) from mark-to-market activities (see Note 4)	(4,897)	(43,656)	1,705	(53,765)
Total revenues	11,812	24,424	35,572	40,228
Expenses:				
Operating expenses:				
Lease operating expenses	6,284	6,602	13,045	14,022
Cost of sales	251	542	636	1,061
Production taxes	509	660	1,057	1,431
General and administrative	3,791	4,012	7,732	8,235
Exploration costs				131
(Gain) / Loss on sale of assets	(4)	14		21
Depreciation, depletion, and amortization	4,358	5,893	8,774	11,758
Asset impairments			107	
Accretion expense	192	226	383	452
Total operating expenses	15,381	17,949	31,734	37,111
Other expenses (income)				
Interest expense	1,951	2,691	3,662	5,214
Interest expense-(Gain)/Loss from mark-to-market activities (see Note 4)	(513)	1,385	(605)	715
Interest (income)	(1)		(1)	(1)
Other expense (income)	4	(68)	(93)	(126)
Total other expenses / (income)	1,441	4,008	2,963	5,802
Total expenses	16,822	21,957	34,697	42,913
Net income (loss)	$ (5,010)	$ 2,467	$ 875	$ (2,685)
Change in fair value of commodity hedges	65	75	88	99
Cash settlement of commodity hedges	(1,927)	(1,960)	(2,645)	(2,684)
Other comprehensive income (loss)	(1,862)	(1,885)	(2,557)	(2,585)
Comprehensive income (loss)	$ (6,872)	$ 582	$ (1,682)	$ (5,270)
Earnings (loss) per unit (see Note 2)				
Earnings (loss) per unit Basic	$ (0.21)	$ 0.10	$ 0.04	$ (0.11)
Units outstanding Basic	24,159,301	24,273,244	24,173,012	24,291,246
Earnings (loss) per unit Diluted	$ (0.21)	$ 0.10	$ 0.04	$ (0.11)
Units outstanding Diluted	24,277,769	24,273,244	24,232,246	24,291,246

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 Statements of Cash Flows

(Unaudited)

	Six months ended June 30, 2012	2011
	(In 000 s)	
Cash flows from operating activities:		
Net income (loss)	$ 875	$ (2,685)
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion and amortization	8,774	11,758
Asset impairments (see Note 6)	107	
Amortization of debt issuance costs	646	900
Accretion expense	383	452
Equity (earnings) losses in affiliate	(108)	(162)
(Gain) Loss from disposition of property and equipment		21
Bad debt expense	26	8
(Gain) Loss from mark-to-market activities	(2,310)	54,480
Unit-based compensation programs	681	714
Changes in Assets and Liabilities:		
Change in net risk management assets and liabilities		
(Increase) decrease in accounts receivable	1,580	(780)
(Increase) decrease in prepaid expenses	(177)	(74)
(Increase) decrease in other assets	(599)	(792)
Increase (decrease) in accounts payable	(353)	(227)
Increase (decrease) in accrued liabilities	(4,014)	(3,746)
Increase (decrease) in royalty payable	(495)	202
Increase (decrease) in other liabilities	353	79
Net cash provided by operating activities	5,369	60,148
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash acquired		280
Development of oil and natural gas properties	(6,869)	(4,651)
Proceeds from sale of assets	1,505	56
Distributions from equity affiliate	100	230
Net cash used in investing activities	(5,264)	(4,085)
Cash flows from financing activities:		
Members distributions		
Proceeds from issuance of debt		
Repayment of debt	(10,000)	(49,500)
Units tendered by employees for tax withholdings	(183)	(296)
Equity issue costs		(46)
Debt issue costs	(3)	(647)
Net cash used in financing activities	(10,186)	(50,489)
Net (decrease) increase in cash	(10,081)	5,574

Cash and cash equivalents, beginning of period	17,176	7,892
Cash and cash equivalents, end of period	$ 7,095	$ 13,466
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 668	$ 116
Cash received during the period for interest	$ 1	$ 1
Cash paid during the period for interest	$ (1,974)	$ (3,035)

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	Total Members
	Units	Amount	Units	Amount	(Loss)	Equity
			(In 000 s, except unit amounts)			
Balance, December 31, 2011	485,033	$ 4,030	23,766,632	$ 197,453	$ 5,437	$ 206,920
Distributions						
Units tendered by employees for tax withholding	(1,594)	(4)	(78,131)	(179)		(183)
Change in fair value of commodity hedges					88	88
Cash settlement of commodity hedges					(2,645)	(2,645)
Unit-based compensations programs	92	14	4,517	667		681
Net income		17		858		875
Balance, June 30, 2012	483,531	$ 4,057	23,693,018	$ 198,799	$ 2,880	$ 205,736

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, 2012, 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, 2011, which was filed on March 1, 2012. Certain amounts in the consolidated financial statements and notes thereto have been reclassified to conform to the 2012 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, un the laws of the State of Delaware. We completed our initial public offering on November 20, 2006, and currently trade on the NYSE MKT LLC (NYSE MKT) under the symbol CEP . Through subsidiaries, both PostRock Energy Corporation (NASDAQ: PSTR) (PostRock) and Exelon Corporation (NYSE: EXC) (Exelon), own a portion of our outstanding units. As of June 30, 2012, Constellation Energy Partners Management, LLC (CEPM), a subsidiary of PostRock, owns all of our Class A units and 5,918,894 of our Class B common units. Constellation Energy Partners Holdings, LLC (CEPH), a subsidiary of Exelon, owns all of our Class C management incentive interests 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.

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, 2011.

Earnings per Unit

Basic earnings per unit (EPU) are computed by dividing net income attributable to unitholders by the weighted average number of units outstanding during each period. At June 30, 2012, we had 483,531 Class A units and 23,693,018 Class B common units outstanding. Of the Class B common units, 805,288 units are restricted unvested common units granted and outstanding. We also have an additional 399,240 unvested Class B common units that have been granted but are subject to performance conditions which vest, if earned, on January 2, 2013.

The following table presents earnings per common unit amounts:

	Income	Weighted Average Unit Outstanding	Per Unit Amount
	(In 000 s except unit data)		
For the three months ended June 30, 2012			
Basic EPU:			

Income (loss) allocable to unitholders	$ (5,010)	24,159,301	$ (0.21)
Diluted EPU:			
Income (loss) allocable to unitholders	$ (5,010)	24,277,769	$ (0.21)

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	Income	Weighted Average Units Outstanding (In 000 s except unit data)	Per Unit Amount
For the six months ended June 30, 2012			
Basic EPU:			
Income (loss) allocable to unitholders	$ 875	24,173,012	$ 0.04
Diluted EPU:			
Income (loss) allocable to unitholders	$ 875	24,232,246	$ 0.04

	Income	Weighted Average Units Outstanding (In 000 s except unit data)	Per Unit Amount
For the three months ended June 30, 2011			
Basic EPU:			
Income (loss) allocable to unitholders	$ 2,467	24,273,244	$ 0.10
Diluted EPU:			
Income (loss) allocable to unitholders	$ 2,467	24,273,244	$ 0.10

	Income	Weighted Average Units Outstanding (In 000 s except unit data)	Per Unit Amount
For the six months ended June 30, 2011			
Basic EPU:			
Income (loss) allocable to unitholders	$ (2,685)	24,291,246	$ (0.11)
Diluted EPU:			
Income (loss) allocable to unitholders	$ (2,685)	24,291,246	$ (0.11)

Cash

All highly liquid investments with original maturities of three months or less are considered cash. Checks-in-transit were $1.2 million at June 30, 2012, and $1.8 million at December 31, 2011 and are included in accounts payable in our consolidated balance sheets. We have also established an escrow account for $0.6 million related to a vendor dispute, which is included in other assets in our consolidated balance sheets at June 30, 2012, and December 31, 2011. This amount will remain in the escrow account until the dispute has been resolved.

3. RECENT ACCOUNTING PRONOUNCEMENTS AND ACCOUNTING CHANGES

In December 2011, the FASB issued ASU No. 2011-11, *Disclosures about Offsetting Assets and Liabilities,* which requires additional disclosures for financial and derivative instruments that are either (1) offset in accordance with either Accounting Standards Codification (ASC) 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, regardless of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. The guidance is effective beginning on or after January 1, 2013, and will primarily impact the disclosures associated with our commodity and interest rate derivatives. We do not expect this guidance to have any impact on our consolidated financial position, results of operations or cash flows.

In June 2011, the FASB issued ASU 2011-05, *Comprehensive Income (Topic 220)* 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 was eliminated. In December 2011, the FASB issued new authoritative accounting guidance which effectively deferred the requirement to present the reclassification adjustments on the face of the financial statements. The amended guidance was effective for us in the first quarter of 2012 and implementation of this guidance did 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 was effective for interim and annual periods beginning on or after December 15, 2011. The amended guidance was effective for us in the first quarter of 2012 and implementation of this guidance did not have a material impact on our financial statements or our disclosures.

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4. DERIVATIVE AND FINANCIAL INSTRUMENTS

Mark-to-Market Activities

As of June 30, 2012, 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 $87.0 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, 2012.

For the six months ended June 30, 2012 and 2011, we recognized mark-to-market gains of approximately $1.7 million and mark-to-market losses of approximately $53.7 million, respectively, in connection with our commodity derivatives. For the six months ended June 30, 2012 and 2011, we recognized a mark-to-market gain of approximately $0.6 million and a gain of $0.2 million, respectively, in connection with our interest rate derivatives. At June 30, 2012 and December 31, 2011, the fair value of our derivatives accounted for as mark-to-market activities amounted to a net asset of approximately $37.0 million and a net asset of approximately $37.2 million, respectively.

Accumulated Other Comprehensive Income

Prior to the first quarter of 2009, we accounted for certain of our commodity 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 $2.9 million and $5.4 million at June 30, 2012 and December 31, 2011, 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
September 30, 2012	$ 1,722	$ (63)	$ 1,659
December 31, 2012	1,271	(50)	1,221
Total	$ 2,993	$ (113)	$ 2,880

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.

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 and interest rate 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. 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. Our commodity derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of oil and natural gas prices, and an appropriate discount rate. Our interest rate derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of the LIBOR interest rates, and an appropriate discount rate. We prioritize the use of the highest level inputs available in determining fair value such that fair value measurements are determined using the highest and best use as determined by market participants and the assumptions that they would use 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.

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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, 2012 and December 31, 2011.

At June 30, 2012	**Commodity and Interest Rate Derivatives Level 1**	**Level 2**	**Level 3**	**Netting and Cash Collateral***	**Total Net Fair Value**
			(In 000 s)		
Risk management assets	$	$ 47,209	$	$ (9,821)	$ 37,388
Risk management liabilities	$	$ (10,233)	$	$ 9,821	$ (412)
Total net assets and liabilities	$	$ 36,976	$	$	$ 36,976

* *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. Amounts shown represent the impact of netting assets and liabilities with our counterparties for which the right of offset exists.*

At December 31, 2011	**Commodity and Interest Rate Derivatives Level 1**	**Level 2**	**Level 3**	**Netting and Cash Collateral***	**Total Net Fair Value**
			(In 000 s)		
Risk management assets	$	$ 50,940	$	$ (13,054)	$ 37,886
Risk management liabilities	$	$ (13,718)	$	$ 13,054	$ (664)
Total net assets and liabilities	$	$ 37,222	$	$	$ 37,222

* *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. Amounts shown represent the impact of netting assets and liabilities with our counterparties for which the right of offset exists.*

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, 2012, the impact of non-performance credit risk on the valuation of our net assets from counterparties was $0.5 million, of which $0.4 million was reflected as a decrease to our non-cash mark-to-market gain and $0.1 million was reflected as a reduction to our accumulated other comprehensive income. 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 an increase to our non-cash mark-to-market loss and $0.3 million was reflected as a reduction to our accumulated other comprehensive income.

Fair Value of Financial Instruments

As of June 30, 2012, we have interest rate swaps on $87.0 million of outstanding debt for various maturities extending through November 2014, various commodity swaps for 22,818,854 MMbtu of natural gas production through December 2014, various basis swaps for 12,821,389 MMbtu of natural gas production in the Cherokee Basin through December 2014, and various commodity swaps for 257,478 Bbls of oil production through December 2015.

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The following represents the fair value for our risk management assets and liabilities, as of June 30, 2012, and 2011, and December 31, 2011:

Derivative Type	Location of Asset/ (Liability) on Balance Sheet	Fair Value of Asset/ (Liability) on Balance Sheet (in 000 s) Quarter Ended June 30, 2012	Year Ended December 31, 2011
Commodity-MTM	Risk management assets-current	$ 25,724	$ 27,208
Commodity-MTM	Risk management assets-non-current	21,485	23,732
	Total gross assets	47,209	50,940
Commodity-MTM	Risk management assets-current	(4,704)	(6,925)
Commodity-MTM	Risk management assets-non-current	(917)	(1,325)
Commodity-MTM	Risk management liabilities-current		(378)
Commodity-MTM	Risk management liabilities-non-current	(412)	(286)
Interest Rate-MTM	Risk management assets-non-current	(4,200)	(4,804)
	Total gross liabilities	(10,233)	(13,718)
	Total net assets and liabilities	$ 36,976	$ 37,222

Derivative Type	Location of Gain / (Loss) in Income	Amount of Gain / (Loss) in Income (in 000 s) Quarter Ended June 30, 2012	Quarter Ended June 30, 2011
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ (4,897)	$ (43,656)
Commodity-MTM	Natural gas sales	7,307	49,282
Commodity-MTM	Oil and liquids sales	34	
Interest Rate-MTM	Interest expense-Gain/(Loss) from mark-to- market activities	513	(1,385)
Interest Rate-MTM [a]	Interest expense	(793)	(526)
	Total	$ 2,164	$ 3,715

Derivative Type	Location of Gain / (Loss) in Income	Amount of Gain / (Loss) in Income (in 000 s) Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Commodity-MTM	Gain/(Loss) from mark-to-market activities	$ 1,705	$ (53,765)
Commodity-MTM	Natural gas sales	13,266	59,077
Commodity-MTM	Oil and liquids sales	123	
Interest Rate-MTM	Interest expense-Gain/(Loss) from mark-to- market activities	605	(715)

Interest Rate-MTM [a]	Interest expense	(1,285)	(1,062)
	Total	$ 14,414	$ 3,535

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Derivative Type	Location of Gain / (Loss) for Effective and Ineffective Portion of Derivative in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income - Effective Quarter Ended June 30, 2012	Quarter Ended June 30, 2011
Commodity-Cash Flow	Natural gas sales	$ 1,927	$ 1,960
	Total	$ 1,927	$ 1,960

Derivative Type	Location of Gain / (Loss) for Effective and Ineffective Portion of Derivative in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income - Effective Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Commodity-Cash Flow	Natural gas sales	$ 2,645	$ 2,684
	Total	$ 2,645	$ 2,684

(a) These tables for 2011 reflect the impact of revising our June 30, 2011 quarterly data for a non-cash mark-to-market correction to interest expense. The net impact of this non-cash adjustment was a decrease to our interest expense in the amount of $0.8 million for the three months and six months ended June 30, 2011, and a $(0.04) impact on earnings per unit. This non-cash adjustment had been revised during the twelve months ended December 31, 2011. We have determined that the adjustment is not material to our consolidated financial statements for any of the 2011 quarterly periods affected or to the 2011 annual period.

At June 30, 2012, the carrying values of our cash, 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 for our reserve-based credit facility approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms, which is a Level 2 measurement in the fair value hierarchy and represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties. Our reserve-based credit facility is discussed in Note 5.

The carrying value and the fair market value of the awards granted under our unit-based compensation plans are discussed in Note 10.

5. DEBT

Reserve-Based Credit Facility

On June 3, 2011, we executed a second amendment to our $350.0 million reserve-based credit facility with The Royal Bank of Scotland plc as administrative agent and a syndicate of lenders extending its maturity date to 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. As of June 30, 2012, the lenders and their percentage commitments in the reserve-based credit facility are The Royal Bank of Scotland plc (26.84%), Wells Fargo Bank N.A. (Wells Fargo) (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, 2012, our borrowing base was $90.0 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, using, among other things, the oil and natural gas prices prevailing at such time. Our latest semi-annual borrowing base redetermination occurred during the second quarter of 2012 and our outstanding balance at November 13, 2012, will become a current liability. 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, 2012, no letters of credit were 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. A change of control is generally defined as the occurrence of both of the following events: (i) wholly owned subsidiaries of Constellation Energy Group, Inc. are the owner of 20% or less of an interest in us (which has now occurred) and (ii) any person or group of persons acting in concert are the owner of more than 35% of an interest in us. 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.

The reserve-based credit facility limits our ability to pay distributions to unitholders. 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 June 30, 2012, 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 PostRock s or Exelon s ownership in us.

Debt Issue Costs

As of June 30, 2012, our unamortized debt issue costs were approximately $1.8 million. These costs are being amortized over the life of our reserve-based credit facility through November 2013.

Funds Available for Borrowing

As of June 30, 2012 and 2011, we had $88.4 million and $115.5 million, respectively, in outstanding debt under our reserve-based credit facility. As of June 30, 2012, we had $1.6 million in remaining borrowing capacity under our reserve-based credit facility.

Compliance with Debt Covenants

At June 30, 2012, 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, 2012, our actual Total Net Debt to annual Adjusted EBITDA ratio was 2.1 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 1.5 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 7.3 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. 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 our reserve-based credit facility, the outstanding debt balance at November 13, 2012, will become a current liability.

6. OIL AND NATURAL GAS PROPERTIES

Natural gas properties consist of the following:

	June 30, 2012	December 31, 2011
	(In 000 s)	
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 790,344	$ 785,089
Unproved property	1,371	1,321
Total property costs	791,715	786,410
Materials and supplies	1,636	1,243
Land	912	912
Total	794,263	788,565
Less: Accumulated depreciation, depletion, amortization and impairments	(530,831)	(522,480)
Natural gas properties and equipment, net	$ 263,432	$ 266,085

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

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(In 000 s)	
DD&A of oil and natural gas-related properties and assets	$ 8,774	$ 11,758
Asset Impairments	107	
Total	$ 8,881	$ 11,758

Impairment of Oil and Natural Gas Properties and Other Non-Current Assets

In the first quarter of 2012, we recorded a total non-cash impairment charge of approximately $0.1 million to impair certain of our wells in the Woodford Shale. This impairment was recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by estimated cash flows reported in a third party reserve report. This report was based upon future oil and natural gas prices, which are based on observable inputs adjusted for basis differentials, which are Level 2 inputs in the fair value hierarchy. Significant assumptions in valuing the proved reserves included the reserve quantities, anticipated operating costs, anticipated production taxes, future expected oil and natural gas prices and basis differentials, anticipated production declines, and an appropriate discount rate commensurate with the risk of the underlying cash flow estimates for the properties of 10.0%. The impairment was primarily caused by the impact of lower future oil and natural gas prices on future expected cash flows during the first quarter of 2012. After the impairment, the remaining net capitalized costs subject to impairment in the Woodford Shale is approximately $3.6 million. Cash flow estimates for the impairment testing exclude derivative instruments used to mitigate the risk of lower future oil and natural gas prices. This asset impairment has no impact on our cash flows, liquidity position, or debt covenants.

Asset Sales

Through the six months ended June 30, 2012, we sold our interests in 14 gross non-operated oil wells in Kansas and Nebraska for approximately $1.4 million in cash, and sold approximately $0.1 million in trucks and equipment resulting in no material gain or loss on the asset sales.

Useful Lives

Our furniture, fixtures, and equipment are depreciated over a life of one to five 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 none and $0.1 million in the six months ended June 30, 2012 and 2011, 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

Both PostRock and Exelon, through subsidiaries, own a portion of our outstanding units. As of June 30, 2012, CEPM, a subsidiary of PostRock, owns all of our Class A units and 5,918,894 of our Class B common units. CEPH, a subsidiary of Exelon, owns all of our Class C management incentive interests and all of our Class D interests.

Class C Management Incentive Interests

CEPH, a subsidiary of Exelon, 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. None of these applicable tests have yet to be met and CEPH has not been entitled to receive any management incentive interest distributions.

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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 and third-party litigation and lawsuits. As of June 30, 2012, 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.

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 oil and 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.

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:

	For the Six Months Ended June 30, 2012	For the Year Ended December 31, 2011
	(In 000 s)	
Asset retirement obligation, beginning balance	$ 14,047	$ 13,024
Liabilities incurred	80	143
Liabilities settled	(3)	(27)
Revisions to prior estimates		
Accretion expense	383	907
Asset retirement obligation, ending balance	$ 14,507	$ 14,047

Additional asset 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, 2012, and December 31, 2011, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing asset retirement obligations.

10. COMPENSATION

We recognized approximately $0.7 million and $0.7 million of non-cash compensation expense related to our unit-based compensation plans in the six months ended June 30, 2012, and June 30, 2011, respectively. As of June 30, 2012, we had approximately $2.7 million in unrecognized compensation expense related to our unit-based compensation plans expected to be recognized through the first quarter of 2015.

2012 Compensation Actions

Long-term Incentives

On June 4, 2012, the Company made (i) a performance-based grant to be settled in Class B common units of the Company, if earned, and (ii) a performance-based grant to be settled in cash, if earned, to each of our named executive officers under the 2009 Omnibus Incentive Compensation Plan or the Long-Term Incentive Plan, as applicable, in each case based on actual performance relative to pre-determined, equally weighted 2012 goals for natural gas and oil and natural gas liquids production at stated threshold, target and maximum performance levels, as applicable.

Unit-Based Awards

The unit-based awards contain a threshold and target payout level. No award payouts will be made for actual performance below a threshold level. For performance within the target range, award payouts will be made at 100%. For actual performance between the threshold and target level, award payouts will be determined using a linear interpolation between the threshold level and the low end

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of the target level. Awards will be earned based upon 2012 performance and issuance of the earned units will be made on January 2, 2013, except in the case of death, disability, involuntary termination or certain change of control events, which may accelerate the unit grants. The target awards of these unit-based grants are not part of the target-level bonuses of the named executive officers under their employment agreements.

The pre-determined 2012 performance levels required for a unit-based payout on January 2, 2013, are:

Performance Level	*Payout %*	*Natural Gas Production (weighted 50%)*	*Oil/NGL Production (weighted 50%)*
Target	100%	from 11.4 Bcf to 14.0 Bcf*	from 144 Mbbls to 176 Mbbls*
Threshold	50%	at least 10.2 Bcf	at least 128 Mbbls

* Achievement of the performance metric anywhere within this range will result in a payout of 100% of the target Class B common units, with a linear interpolation between the threshold performance level and the low end of the target range performance level.

The target unit grants for the named executive officers are as follows:

Mr. Brunner 190,114 Class B common units

Mr. Ward 95,057 Class B common units

Ms. Mellencamp 76,046 Class B common units

Mr. Hiney 38,023 Class B common units

The number of target units under these awards was calculated based on the 20-day simple average of the Company s closing common unit price on NYSE MKT through April 5, 2012, or $2.63. During the second quarter of 2012, we recognized approximately $0.1 million of non-cash compensation expense related to these grants. As of June 30, 2012, we had approximately $0.6 million in unrecognized compensation expense related to these grants that is expected to be recognized through the fourth quarter of 2012.

Cash-Based Awards

The cash-based awards contain a threshold, target and maximum payout level. No award payouts will be made for actual performance below a threshold level. For performance within the target range, award payouts will be made at 100%. For actual performance at a maximum level, award payouts will be made at 200%. For actual performance between the threshold and target level and between the target and maximum levels, award payouts will be determined using a linear interpolation between the low and high ends of the target levels, respectively. For actual performance above the target level, each executive also will be paid the cash value of the award times the corresponding percentage above the target performance level (100%) for the performance level achieved. Awards will be earned based upon 2012 performance and will be 100% vested as of December 31, 2012. Payment of the earned cash-based awards will be made on January 2, 2014, except in the case of death, disability, involuntary termination or certain change of control events, which may accelerate payment. The target cash values of the grants are part of the target-level bonuses of the named executive officers under their employment agreements.

The pre-determined 2012 performance levels required for a cash payout on January 2, 2014, are:

Performance Level	*Payout %*

		Natural Gas Production (weighted 50%)	*Oil/NGL Production (weighted 50%)*
Maximum	200%	at least 15.2 Bcf	at least 192 Mbbls
Target	100%	from 11.4 Bcf to 14.0 Bcf*	from 144 Mbbls to 176 Mbbls*
Threshold	50%	at least 10.2 Bcf	at least 128 Mbbls

* Achievement of the performance metric anywhere within this range will result in a payout of 100% of the cash value, with a linear interpolation between the threshold performance level and the low end of the target range performance level and between the high end of the target range performance level and the maximum performance level, respectively.

The target cash payouts for the named executive officers are as follows:

Mr. Brunner	$500,000
Mr. Ward	$250,000
Ms. Mellencamp	$200,000
Mr. Hiney	$100,000

On April 5, 2012, the compensation committee and board of managers made service-based grants to certain other key employees other than our named executive officers. The service-based grants made to certain other key employees under our 2009 Omnibus Incentive Compensation Plan total approximately $1.3 million. The grants, which will be settled in cash, vest 50% on December 31, 2012, and 50% on December 31, 2013, except in the case of an involuntary termination upon certain change of control events, which may accelerate payment for certain key employees.

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During the second quarter of 2012, we recognized approximately $0.6 million of compensation expense related to both of these cash-based award grants discussed above. As of June 30, 2012, we had approximately $1.8 million in unrecognized compensation expense related to these grants that is expected to be recognized through the fourth quarter of 2013.

Unit-Based Awards Granted in 2011

In the second quarter of 2011, the compensation committee of our board of managers and our 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 PostRock 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. The carrying value and the fair market value of these awards was approximately $0.9 million and $0.2 million at the grant date and June 30, 2012, respectively, and is reported as a non-current liability on our balance sheet. There are no significant non-cash compensation expenses related to the program for the six months ended June 30, 2012, as the value of these awards has fallen as the market price for our common units has declined.

11. DISTRIBUTIONS TO UNITHOLDERS

Distributions through June 30, 2012

Beginning in June 2009, we suspended our quarterly distributions to unitholders. For the six months ended June 30, 2012, 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 13 for additional information.

Distributions through June 30, 2011

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.

12. MEMBERS EQUITY

2012 Equity

At June 30, 2012, we had 483,531 Class A units and 23,693,018 Class B common units outstanding, which included 129,369 unvested restricted common units issued under our Long-Term Incentive Plan and 675,919 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan. See Note 13 for additional information.

At June 30, 2012, we had granted 345,221 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 215,852 have vested. We also granted an additional 76,046 performance units under our Long-Term Incentive Plan that are subject to performance conditions which vest, if earned, on January 2, 2013.

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At June 30, 2012, we had granted 1,323,419 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 647,500 have vested. We also granted an additional 323,194 performance units under our 2009 Omnibus Incentive Compensation Plan that are subject to performance conditions which vest, if earned, on January 1, 2013.

For the six months ended June 30, 2012, 78,131 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.2 million, have been returned to their respective plan and are available for future grants.

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.

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.

13. SUBSEQUENT EVENTS

The following subsequent events have occurred between June 30, 2012, and August 8, 2012:

Distribution

Our board of managers has suspended the quarterly distribution to our unitholders for the quarter ended June 30, 2012, which continues the suspension we first announced in June 2009.

Members Equity

2012 Equity

At August 8, 2012, we had 483,304 Class A units and 23,681,878 Class B common units outstanding, which included 94,914 unvested restricted common units issued under our Long-Term Incentive Plan and 665,840 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan.

At August 8, 2012, we had granted 336,599 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 241,685 have vested. We also granted an additional 76,046 performance units under our Long-Term Incentive Plan that are subject to performance conditions which vest, if earned, on January 2, 2013.

At August 8, 2012, we had granted 1,320,901 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 655,061 have vested. We also granted an additional 323,194 performance units under our 2009 Omnibus Incentive Compensation Plan that are subject to performance conditions which vest, if earned, on January 1, 2013.

Through August 8, 2012, 89,271 common units have been tendered by our employees for tax withholding purposes. These units, costing approximately $0.2 million, have been returned to their respective plan and are available for future grants.

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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.

Overview

We are a limited liability company formed in 2005 to acquire oil and natural gas properties. Our oil and natural gas reserves are 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. Our current primary business objective is to create long-term value and to generate stable cash flows allowing us to make 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 and oil opportunities on our existing properties;

- reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient hedging programs; and

- make accretive, right-sized 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.

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 Class B common units are currently listed on the NYSE MKT 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 PostRock and CEPM are to PostRock Energy Corporation and its subsidiary Constellation Energy Partners Management, LLC, respectively. References in this Quarterly Report on Form 10-Q to Exelon and CEPH are to Exelon Corporation and its subsidiary Constellation Energy Partners Holdings, LLC, respectively. References in this Quarterly Report on Form 10-Q to Constellation, CCG, and CHI are to Constellation Energy Group, Inc., Constellation Energy Commodities Group, Inc., and Constellation Holdings, Inc., 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

interest (income) expense, net which includes:

  - interest expense

  - interest expense gain/(loss) mark-to-market activities

  - interest (income)

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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.

We are unable to reconcile our forecast range of Adjusted EBITDA to GAAP net income or operating income because we do not predict the future impact of adjustments to net income (loss), such as (gains) losses from mark-to-market activities and equity investments or asset impairments due to the difficulty of doing so, and we are unable to address the probable significance of the unavailable reconciliation, in significant part due to ranges in our forecast impacted by changes in oil and natural gas prices and reserves which affect certain reconciliation items.

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, 2012	June 30, 2011	June 30, 2012	June 30, 2011
	(In 000 s)			
Reconciliation of Net Income (Loss) to Adjusted EBITDA:				
Net income (loss)	$ (5,010)	$ 2,467	$ 875	$ (2,685)
Adjusted by:				
Interest expense/(income), net	1,437	4,076	3,056	5,928
Depreciation, depletion and amortization	4,358	5,893	8,774	11,758
Asset impairments			107	
Accretion expense	192	226	383	452
(Gain)/Loss on sale of assets	(4)	14		21
Exploration costs				131
Unit-based compensation programs	394	341	681	714
(Gain)/Loss on mark-to-market activities	4,897	43,656	(1,705)	53,765
Adjusted EBITDA	$ 6,264	$ 56,673	$ 12,171	$ 70,084

Our Adjusted EBITDA increased from $5.9 million in the first quarter of 2012 to $6.3 million in the second quarter of 2012, or a 6% increase. Our Adjusted EBITDA increased from quarter-to-quarter because of lower total cash operating expenses and higher realized prices received for our oil and natural gas sales.

Our Adjusted EBITDA was $12.2 million for the six months ended June 30, 2012, lower than our Adjusted EBITDA of $70.1 million in the same period in 2011. During 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 December 2014. At that time, we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million which was used to reduce our outstanding debt level. As a result of this resetting of our swap positions, we would expect that our operating cash flows and Adjusted EBITDA would be lower. This is because of the expected decrease in the value of future cash hedge settlements on the reset NYMEX positions from January 2012 through December 2014. 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 reduced the amount of our outstanding debt with the one-time cash payment we received.

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We anticipate that our 2012 capital expenditures could allow us to maintain our 2012 production at relatively the same level as in 2011. Our current 2012 capital budget is expected to be between $15.0 million and $19.0 million and will focus on higher return oil opportunities and capital efficient recompletions. We intend to manage our business to operate within the cash flows that are generated by our existing asset base.

Significant Operational Factors

Realized Prices. Our average realized price for the six months ended June 30, 2012, was $5.32 per Mcfe including hedge settlements and $3.22 per Mcfe excluding hedge settlements. After deducting the cost of sales associated with third party gathering, our average realized prices were $5.22 per Mcfe including hedge settlements and $3.12 per Mcfe excluding hedge settlements.

Production. Our production for the six months ended June 30, 2012, was 6.4 Bcfe, or an average of 34,989 Mcfe per day, compared with approximately 7.0 Bcfe, or an average of 38,503 Mcfe per day, for the six months ended June 30, 2011. This 2012 production is lower than the production for the same period in 2011 because of the natural production declines associated with our existing wells not yet being offset by the anticipated new production from our 2012 drilling program. A substantial portion of our 2012 drilling program is expected to be completed during the last half of the year.

Capital Expenditures and Drilling Results. During the first six months of 2012, we spent approximately $6.9 million in cash capital expenditures, primarily consisting of development expenditures focused on oil completions in the Cherokee Basin. We have completed 21 net wells and 27 net recompletions during the first half of 2012 and have 24 net wells and net recompletions in progress.

Hedging Activities. As of June 30, 2012, all of our commodity and interest rate derivatives are accounted for as mark-to-market activities. For the six months ended June 30, 2012, the unrealized non-cash mark-to-market gain for our commodity derivatives was approximately $1.7 million as compared to an unrealized non-cash mark-to-market loss of $53.7 million for the same period in 2011. We experience earnings volatility as a result of using the mark-to-market accounting method for our open derivative positions. This accounting treatment can cause extreme earnings volatility as the positions for future oil and natural gas production or interest rates 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 or interest payments are made. Further detail of our commodity derivative positions and their accounting treatment is outlined below in Cash Flow From Operations-Open Commodity Hedge Positions .

Debt Reduction. At June 30, 2012, we had $88.4 million in outstanding debt. Through August 8, 2012, we reduced our outstanding debt from a high of $220.0 million in 2009 to $88.4 million or by 59.8%.

Operating Expense Reductions. We continue to look for opportunities to lower our operating expenses. For the six months ended June 30, 2012, we have reduced our lease operating expenses by 7.0% and our general and administrative expenses by 6.1% as compared to the same period in 2011. We will continue to look for opportunities to further reduce our structural general and administrative expenses over the next 12 to 18 months.

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)		
		Variance		Variance

	June 30, 2012	June 30, 2011	$	%	June 30, 2012	June 30, 2011	$	%
Revenues:								
Natural gas sales	$ 13,131	$ 64,070	$ (50,939)	(79.5)%	$ 26,071	$ 86,737	$ (60,666)	(70.0)%
Oil and liquids sales	$ 2,900	$ 2,827	$ 73	2.5%	$ 6,180	$ 4,907	$ 1,273	25.9%
Gain / (Loss) from mark-to-market activities	(4,897)	(43,656)	38,759	(88.8)%	1,705	(53,765)	55,470	(103.2)%
Other	$ 678	$ 1,183	$ (505)	(42.7)%	$ 1,616	$ 2,349	$ (733)	(31.2)%
Total revenues	11,812	24,424	(12,612)	(51.6)%	35,572	40,228	(4,656)	(11.6)%
Operating expenses:								
Lease operating expenses	6,284	6,602	(318)	(4.8)%	13,045	14,022	(977)	(7.0)%
Cost of sales	251	542	(291)	(53.7)%	636	1,061	(425)	(40.1)%
Production taxes	509	660	(151)	(22.9)%	1,057	1,431	(374)	(26.1)%
General and administrative expenses	3,791	4,012	(221)	(5.5)%	7,732	8,235	(503)	(6.1)%
Exploration costs						131	(131)	(100.00)%
(Gain) / loss on sale of assets	(4)	14	(18)	(128.6)%		21	(21)	(100.00)%
Depreciation, depletion and amortization	4,358	5,893	(1,535)	(26.0)%	8,774	11,758	(2,984)	(25.4)%

	For the Three Months Ended				(Dollars in 000 s) For the Six Months Ended			
	June 30, 2012	June 30, 2011	Variance $	Variance %	June 30, 2012	June 30, 2011	Variance $	Variance %
Asset impairments					107		107	
Accretion expenses	192	226	(34)	(15.0)%	383	452	(69)	(15.3)%
Total operating expenses	15,381	17,949	(2,568)	(14.3)%	31,734	37,111	(5,377)	(14.5)%
Other expenses (income):								
Interest expense	1,951	2,691	(740)	(27.5)%	3,662	5,214	(1,552)	(29.8)%
Interest expense-(Gain)/loss from mark-to-market activities	(513)	1,385	(1,898)	(137.0)%	(605)	715	(1,320)	(184.6)%
Interest income	(1)		(1)		(1)	(1)		0.0%
Other (income) expense	4	(68)	72	(105.9)%	(93)	(126)	33	(26.2)%
Total other expenses (income)	1,441	4,008	(2,567)	(64.0)%	2,963	5,802	(2,839)	(48.9)%
Total expenses	16,822	21,957	(5,135)	(23.4)%	34,697	42,913	(8,216)	(19.1)%
Net income (loss)	$ (5,010)	$ 2,467	$ (7,477)	(303.1)%	$ 875	$ (2,685)	$ 3,560	132.6%
Net production:								
Natural gas production (MMcf)	2,966	3,417	(451)	(13.2)%	6,015	6,693	(678)	(10.1)%
Oil and liquids production (MBbl)	29	21	8	38.1%	58	46	12	26.1%
Total production (MMcfe)	3,142	3,545	(403)	(11.4)%	6,368	6,969	(601)	(8.6)%
Average daily production (Mcfe/d)	34,527	38,956	(4,429)	(11.4)%	34,989	38,503	(3,514)	(9.1)%
Average sales prices:								
Natural gas price per Mcf with hedge settlements	$ 4.69	$ 19.10	$ (14.41)	(75.5)%	$ 4.62	$ 13.31	$ (8.69)	(65.3)%
Natural gas price per Mcf without hedge settlements	$ 2.19	$ 4.10	$ (1.91)	(46.6)%	$ 2.40	$ 4.08	$ (1.68)	(41.2)%
Oil and liquids price per Bbl with hedge settlements	$ 96.83	$ 134.62	$ (37.79)	(28.1)%	$ 104.97	$ 106.67	$ (1.70)	(1.6)%
Oil and liquids price per Bbl without hedge settlements	$ 98.83	$ 134.62	$ (35.79)	(26.6)%	$ 104.43	$ 106.67	$ (2.24)	(2.1)%
Total price per Mcfe with hedge settlements	$ 5.32	$ 19.20	$ (13.88)	(72.3)%	$ 5.32	$ 13.49	$ (8.17)	(60.6)%
Total price per Mcfe without hedge settlements	$ 2.98	$ 4.75	$ (1.77)	(37.3)%	$ 3.22	$ 4.63	$ (1.41)	(30.5)%
Average unit costs per Mcfe:								
Field operating expenses[a]	$ 2.16	$ 2.05	$ 0.11	5.4%	$ 2.21	$ 2.22	$ (0.01)	(0.5)%
Lease operating expenses	$ 2.00	$ 1.86	$ 0.14	7.5%	$ 2.05	$ 2.01	$ 0.04	2.0%
Production taxes	$ 0.16	$ 0.19	$ (0.03)	(15.8)%	$ 0.17	$ 0.21	$ (0.04)	(19.0)%
General and administrative	$ 1.21	$ 1.13	$ 0.08	7.1%	$ 1.21	$ 1.18	$ 0.03	2.5%
General and administrative w/o unit-based compensation	$ 1.09	$ 1.05	$ 0.04	3.8%	$ 1.11	$ 1.09	$ 0.02	1.8%
Depreciation, depletion and amortization	$ 1.39	$ 1.66	$ (0.27)	(16.3)%	$ 1.38	$ 1.69	$ (0.31)	(18.3)%

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

Three months ended June 30, 2012 compared to three months ended June 30, 2011

Oil and natural gas sales. Oil and natural gas sales decreased $51.4 million, or 75.5%, to $16.7 million for the three months ended June 30, 2012 as compared to $68.1 million for the same period in 2011. Of this decrease, $43.9 million was attributable to lower cash hedge settlements from our hedge program, $5.6 million was attributable to lower market prices for our natural gas production partially offset by higher market prices for our oil production, and $1.9 million was attributable to decreased natural gas production volumes partially offset by higher oil production volumes. Production for the three months ended June 30, 2012 was 3.1 Bcfe, which was 0.4 Bcfe lower than the same period in 2011. This decrease was associated with natural declines in our natural gas production in the Cherokee Basin, partially offset by increased oil production from our properties in the Cherokee Basin and in the Central Kansas Uplift. Production from our Black Warrior Basin and Woodford Shale properties remained level. Due to the decrease in the level of our drilling activities during 2010 and 2011, our maintenance drilling programs have not been sufficient to offset the natural decline rate of production associated with our existing wells. We hedged approximately 78% of our actual production through June 30, 2012, and approximately 73% of our actual production during the same period in 2011.

Cash hedge settlements received for our commodity derivatives were approximately $7.3 million for the three months ended June 30, 2012. Cash hedge settlements received for our commodity derivatives were approximately $51.2 million for the three months ended June 30, 2011. This difference is due to our lower hedged prices and hedged volumes in 2012 and the impact of significantly lower market prices for natural gas during 2012. The primary reason our cash hedge settlements were lower in 2012 was due to the reset of our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production beginning in January 2012 through December 2014 where we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million in 2011.

As discussed below, the loss from our unrealized non-cash mark-to-market activities decreased by $38.8 million for the three months ended June 30, 2012, as compared to the same period in 2011. Our realized prices before our hedging program decreased from 2011 to 2012 primarily due to net lower market prices for our natural gas production. This was offset by our hedging program and the mark-to-market gains and losses discussed below.

Hedging and mark-to-market activities. All of our derivatives are accounted for as mark-to-market activities. For the three months ended June 30, 2012, the unrealized non-cash mark-to-market loss was approximately $4.9 million as compared to an unrealized non-cash mark-to-market loss of $43.7 million for the same period in 2011. These losses represent the change in the estimated fair value of our open derivative positions for each period. In 2012, we have fewer volumes hedged at a lower price than during the same period in 2011. The 2012 non-cash loss represents approximately $5.1 million from the impact of future expected oil and natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities, offset by $0.2 million related to non-performance risk associated with our counterparties. The 2011 non-cash loss represented approximately $43.2 million from the impact of the reset of our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production from January 2012 through 2014 and $0.5 million related to non-performance risk associated with our counterparties.

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, 2012, lease operating expenses decreased $0.3 million, or 4.8%, to $6.3 million, compared to expenses of $6.6 million for the same period in 2011. This decrease in lease operating expenses is primarily related to $0.2 million in lower expenses in the Black Warrior Basin and $0.1 million in lower expenses in the Cherokee Basin, while our Woodford Shale properties remained flat. By category, our lease operating expenses were lower in 2012 as compared to 2011 by $0.3 million because of decreases of $0.1 million in road and lease maintenance, $0.1 million in gas compression and $0.1 million in labor.

For the three months ended June 30, 2012, per unit lease operating expenses were $2.00 per Mcfe compared to $1.86 per Mcfe for the same period in 2011. This increase is attributable to 11.4% lower production in 2012 as compared to the same period in 2011, offset by a decrease in total spending of 4.8% in 2012 as compared to the same period in 2011.

For the three months ended June 30, 2012, production taxes decreased $0.2 million, or 22.9%, to $0.5 million, compared to expenses of $0.7 million for the same period in 2011. This decrease was primarily the result of lower market prices for natural gas in 2012 and the impact of production taxes on 0.4 Bcfe in lower production in 2012, offset by higher market prices for oil in 2012.

Cost of sales. For the three months ended June 30, 2012, cost of sales decreased by $0.3 million, or 53.7%, to $0.2 million, compared to $0.5 million for the same period in 2011. 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 in 2012, 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 5.5%, to $3.8 million for the three months ended June 30, 2012, as compared to $4.0 million for the same period in 2011. Our general and administrative expenses were lower in 2012 as compared to 2011 because of $0.2 million in lower labor and $0.1 million in lower consulting and professional services, offset by $0.1 million in higher non-cash unit-based compensation expenses.

Our per unit costs were $1.21 per Mcfe for the three months ended June 30, 2012 compared to $1.13 per Mcfe for the same period in 2011. This increase is attributable to the impact of 0.4 Bcfe in lower production offset by a decrease in total spending of approximately $0.2 million.

Exploration Costs. There were no exploration costs for the three months ended June 30, 2012 and June 30, 2011.

Gain/loss on sale of asset. Our gain/loss on the sale of assets decreased approximately $0.02 million, or 128.6%, to less than a $0.01 million gain for the three months ended June 30, 2012, as compared to a loss of less than $0.02 million for the same period in 2011. In 2012, we sold trucks and surplus equipment at a gain of less than $0.01 million. In 2011, we sold surplus equipment for proceeds of less than $0.04 million, which exceeded the book value of the assets.

Depreciation, depletion and amortization expense and Asset Impairments. 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 oil or natural gas production changes, depletion would change in the same direction.

Our depreciation, depletion and amortization expense for the three months ended June 30, 2012 was $4.4 million, or $1.39 per Mcfe, compared to $5.9 million, or $1.66 per Mcfe, for the same period in 2011. This decrease in 2012 depreciation, depletion, and amortization reflects the increase in our reserve base at December 31, 2011, primarily due to increased oil reserves as a result of our successful drilling programs and reserve revisions as a result of lower operating expenses in the Cherokee Basin, increased capital expenditures incurred for our drilling programs in 2012 and a 0.4 Bcfe decrease in production volumes during 2012 as compared to 2011. 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 2011 reserve report to calculate our depletion rate during the first three quarters of 2012 and will use our 2012 reserve report to record our depletion in the fourth quarter of 2012.

Interest expense. Interest expense for the three months ended June 30, 2012 decreased $2.6 million, or 64.7%, to $1.5 million as compared to $4.1 million in interest expense for the same period in 2011. This decrease was primarily due to $1.9 million in lower non-cash mark-to-market losses on our interest rate swaps that are accounted for as mark-to-market activities, lower market interest expense on our outstanding debt of $0.9 million, lower amortization of debt issue costs of $0.1 million, and higher interest rate swap settlements of $0.3 million, while capitalized interest essentially remained level during 2012 as compared to the same period in 2011. At June 30, 2012, we had an outstanding balance under our reserve-based credit facility of $88.4 million as compared to $115.5 million at June 30, 2011. The average interest rate on our outstanding debt was approximately 6.0% in 2012 compared to 5.4% in 2011. We use interest rate swaps to reduce our exposure to changes in the LIBOR rate. If we reduce our outstanding debt balance to the level of, or lower than, the $87.0 million in outstanding interest rate swaps, our cash interest costs for our effective LIBOR rate would begin to approximate the cash settlements on our interest rate swaps.

Interest income. Interest income for the three months ended June 30, 2012, was less than $0.01 million as compared to less than $0.01 million for the same period in 2011. During 2012, 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, 2012, the balance was an unrealized gain of $2.9 million compared to an unrealized gain of $5.4 million at December 31, 2011. 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 six months of 2012.

Our 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, 2012, and as an unrealized loss of $1.9 million for the same period in 2011. This loss reflects the settlements during 2012 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 accumulated other comprehensive income (loss) will be amortized to earnings as the positions settle by December 2012.

Six months ended June 30, 2012 compared to six months ended June 30, 2011

Oil and natural gas sales. Oil and natural gas sales decreased $60.1 million, or 64.0%, to $33.9 million for the six months ended June 30, 2012 as compared to $94.0 million for the same period in 2011. Of this decrease, $48.4 million was attributable to lower cash hedge settlements from our hedge program, $9.0 million was attributable to lower market prices for our natural gas production partially offset by higher market prices for our oil production, and $2.8 million was attributable to decreased natural gas production volumes partially offset by higher oil production volumes. Production for the six months ended June 30, 2012 was 6.4 Bcfe, which was 0.6 Bcfe lower than the same period in 2011. This decrease was associated with natural declines in our natural gas production in the Cherokee Basin, partially offset by increased oil production from our properties in the Cherokee Basin and in the Central Kansas Uplift. Production from our Black Warrior Basin and Woodford Shale properties remained level. Due to the decrease in the level of our drilling activities during 2010 and 2011, our 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 through June 30, 2012, and approximately 74% of our actual production during the same period in 2011.

Cash hedge settlements received for our commodity derivatives were approximately $13.4 million for the six months ended June 30, 2012. Cash hedge settlements received for our commodity derivatives were approximately $61.8 million for the six months ended June 30, 2011. This difference is due to our lower hedged prices and hedged volumes in 2012 and the impact of significantly lower market prices for natural gas during 2012. The primary reason our cash hedge settlements were lower in 2012 was due to the

reset of our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production beginning in January 2012 through December 2014 where we received a one-time cash payment from our swap counterparties totaling approximately $41.3 million in 2011.

As discussed below, the gain from our unrealized non-cash mark-to-market activities increased $55.5 million for the six months ended June 30, 2012, as compared to the same period in 2011. Our realized prices before our hedging program decreased from 2011 to 2012 primarily due to net lower market prices for our natural gas production. This was offset by our hedging program and the mark-to-market gains and losses discussed below.

Hedging and mark-to-market activities. All of our derivatives are accounted for as mark-to-market activities. For the six months ended June 30, 2012, the unrealized non-cash mark-to-market gain was approximately $1.7 million as compared to an unrealized non-cash mark-to-market loss of $53.7 million for the same period in 2011. These gains and losses represent the change in the estimated fair value of our open derivative positions for each period. In 2012, we have lower natural volumes and higher oil volumes hedged at a lower price than during the same period in 2011. The 2012 non-cash gain represents approximately $2.2 million from the impact of future expected oil and natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities, offset by $0.5 million related to non-performance risk associated with our counterparties. The 2011 non-cash loss represents approximately $53.6 million from the impact of the reset of our NYMEX fixed-for-floating price swaps to $5.75 per MMBtu for our natural gas production from January 2012 through 2014 and $0.1 million related to non-performance risk associated with our counterparties.

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, 2012, lease operating expenses decreased $1.0 million, or 7.0%, to $13.0 million, compared to expenses of $14.0 million for the same period in 2011. This decrease in lease operating expenses is primarily related to $0.6 million in lower expenses in the Cherokee Basin and $0.4 million in lower expenses in the Black Warrior Basin, while our Woodford Shale properties remained flat. By category, our lease operating expenses were lower in 2012 as compared to 2011 by $1.0 million because of decreases of $0.3 million in road and lease maintenance, $0.3 million in gas compression, $0.2 million in labor costs and $0.2 million in insurance.

For the six months ended June 30, 2012, per unit lease operating expenses were $2.05 per Mcfe compared to $2.01 per Mcfe for the same period in 2011. This increase is attributable to 8.6% lower production in 2012 as compared to the same period in 2011, offset by a decrease in total spending of 7.0% in 2012 as compared to the same period in 2011.

For the six months ended June 30, 2012, production taxes decreased $0.4 million, or 26.1%, to $1.0 million, compared to expenses of $1.4 million for the same period in 2011. This decrease was primarily the result of lower market prices for natural gas in 2012 and the impact of production taxes on 0.6 Bcfe in lower production in 2012, offset by higher market prices for oil in 2012.

Cost of sales. For the six months ended June 30, 2012, cost of sales decreased by $0.5 million, or 40.1%, to $0.6 million, compared to $1.1 million for the same period in 2011. 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 in 2012, 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 $0.5 million, or 6.1%, to $7.7 million for the six months ended June 30, 2012, as compared to $8.2 million for the same period in 2011. Our general and administrative expenses were lower in 2012 as compared to 2011 because of $0.3 million in lower audit, consulting, and professional services, $0.2 million in lower labor costs and $0.2 million in lower office, telecommunications, and travel expenses, offset by $0.2 million in higher board of managers compensation for our Class A managers.

Our per unit costs were $1.21 per Mcfe for the six months ended June 30, 2012 compared to $1.18 per Mcfe for the same period in 2011. This increase is attributable to the impact of 0.6 Bcfe in lower production offset by a decrease in total spending of approximately $0.5 million.

Exploration Costs. Exploration costs decreased $0.1 million, or 100.0%, to none for the six months ended June 31, 2012, as compared to $0.1 million for the same period in 2011. 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 of $0.1 million in 2012 is primarily the result of lower lease abandonments in the Cherokee Basin and no dry holes in 2012, while there was one dry hole in 2011.

Gain/loss on sale of asset. Our gain/loss on the sale of assets decreased by approximately $0.02 million, or 100.0%, to none for the six months ended June 30, 2012, as compared to a loss of less than $0.02 million for the same period in 2011. In 2012, we sold 14 wells in the Central Kansas Uplift and surplus equipment and trucks at a loss of less than $0.01 million. 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 and Asset Impairments. 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 oil or natural gas production changes, depletion would change in the same direction.

Our depreciation, depletion and amortization expense for the six months ended June 30, 2012 was $8.8 million, or $1.38 per Mcfe, compared to $11.8 million, or $1.69 per Mcfe, for the same period in 2011. This decrease in 2012 depreciation, depletion, and amortization reflects the increase in our reserve base at December 31, 2011, primarily due to increased oil reserves as a result of our successful drilling programs and reserve revisions as a result of lower operating expenses in the Cherokee Basin, increased capital expenditures incurred for our drilling programs in 2012 and a 0.6 Bcfe decrease in production volumes during 2012 as compared to 2011. 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 2011 reserve report to calculate our depletion rate during the first three quarters of 2012 and will use our 2012 reserve report to record our depletion in the fourth quarter of 2012.

Our asset impairments for the six months ended June 30, 2012 were $0.1 million, compared to none for the same period in 2011. Our non-cash impairment charges in 2012 were $0.1 million to impair certain of our wells in the Woodford Shale. This impairment was recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by estimated cash flows reported in a third party reserve report. The impairment was primarily caused by the impact of lower future natural gas prices during the first quarter of 2012 on future expected cash flows.

Interest expense. Interest expense for the six months ended June 30, 2012 decreased $2.9 million, or 48.4%, to $3.0 million as compared to $5.9 million in interest expense for the same period in 2011. This decrease was primarily due to lower market interest expense on our outstanding debt of $1.5 million, $1.3 million in lower non-cash mark-to-market gains on our interest rate swaps that are accounted for as mark-to-market activities, lower amortization of debt issue costs of $0.3 million, and higher interest rate swap settlements of $0.2 million, while capitalized interest essentially remained level during 2012 as compared to the same period in 2011. At June 30, 2012, we had an outstanding balance under our reserve-based credit facility of $88.4 million as compared to $115.5 million at June 30, 2011. The average interest rate on our outstanding debt was approximately 6.0% in 2012 compared to 5.4% in 2011. We use interest rate swaps to reduce our exposure to changes in the LIBOR rate. If we reduce our outstanding debt balance to the level of, or lower than, the $87.0 million in outstanding interest rate swaps, our cash interest costs for our effective LIBOR rate would begin to approximate the cash settlements on our interest rate swaps.

Interest income. Interest income for the six months ended June 30, 2012, was less than $0.01 million as compared to less than $0.01 million for the same period in 2011. During 2012, 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, 2012, the balance was an unrealized gain of $2.9 million compared to an unrealized gain of $5.4 million at December 31, 2011. 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 six months of 2012.

Our 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, 2012, and as an unrealized loss of $2.6 million for the same period in 2011. This loss reflects the settlements during 2012 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 accumulated other comprehensive income (loss) will be amortized to earnings as the positions settle by December 2012.

Liquidity and Capital Resources

During 2011 and through August 8, 2012, we utilized our cash flow from operations as our primary source of capital. Our primary use of capital during this time was for the reduction of outstanding debt and the development of existing oil and natural gas properties within our asset base.

Based upon our current business plan for 2012, we anticipate that we will continue to generate sufficient operating cash flows to meet our working capital needs and fund a planned capital expenditure program that could maintain our total production relatively level with our production in 2011. The timing of any reinstatement of a quarterly distribution to our unitholders is uncertain at this time. The decision to reinstate any future quarterly distributions will consider, among other things, our outstanding borrowings and the borrowing base under our reserve-based credit facility and cash reserves that are set by our board of managers for the proper conduct of our business. Some of the additional factors that could influence this decision include the renewal or replacement of our reserve-based credit facility and the level of commodity prices at that time. Any future quarterly distributions must be approved by our board of managers.

We will be monitoring the capital resources available to us to meet our future financial obligations and our planned 2012 capital expenditures. Our current expectation is that we will manage our business to operate within the cash flows that are generated. We expect that our 2012 capital expenditures will range between approximately $15.0 million and $19.0 million. 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 2012, we anticipate that our cash flow from operations can meet any planned capital expenditures and other cash requirements for the next twelve months without increasing our debt or issuing additional equity securities, although we may raise additional capital if conditions warrant an acceleration of growth opportunities. Future cash flows and our borrowing capacity are subject to a number of variables, including the level of oil and natural gas production, the market prices for those products and our hedge positions. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain our reduced debt level, planned levels of capital expenditures, operating expenses, or any cash distributions that we may make to unitholders.

During 2012, the market price for natural gas declined to the lowest level in ten years due to a record amount of natural gas in storage, significant supply growth and a warmer than normal winter, while oil prices have remained at high levels due to strong worldwide demand for crude oil products and tensions in the Middle East. We have a significant amount of our natural gas production hedged for 2012 through 2014 and our oil production hedged from 2012 through 2015. Our results will not be fully impacted by significant increases or decreases in oil and natural gas prices because of our hedging program. For 2012, we forecast total net production of between 13.3 Bcfe and 14.1 Bcfe. We have hedged approximately 78% of the midpoint of this forecast, including hedges for the balance of 2012 on 3.1 Bcfe of our Mid-Continent natural gas production at an average price, including basis, of $4.62 per Mcfe, 2.4 Bcfe of our remaining natural gas production at an average price of $5.18 per Mcfe, and 46 MBbl of our oil production at an average price of $103.53 per barrel. This hedge position locks in a significant portion of our expected operating cash flows for 2012, although we are still exposed to increases or decreases in oil and natural gas prices on our unhedged volumes. 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.

Sources of Debt and Equity Financing

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 2012, we did not borrow any additional daily, short-term or long-term amounts under our reserve-based credit facility. As of August 8, 2012, the borrowing base under our reserve-based credit facility was $90.0 million and we had $88.4 million of debt outstanding under the facility, leaving us with $1.6 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. Our reserve-based credit facility is discussed below in further detail.

In the first quarter of 2011, we filed a 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 any acquisitions. This registration statement will expire in two years. As a smaller reporting company, any sales of securities under our shelf registration statement during the preceding rolling 12 months is limited to one-third of our public float. Our public float is calculated by multiplying the highest closing price of our Class B common units within the last 60 days by the number of outstanding Class B common units held by non-affiliates, currently including PostRock. 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 reserve-based credit facility with The Royal Bank of Scotland plc as administrative agent and a syndicate of lenders extending its maturity date to 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. As of August 8, 2012, the lenders and their percentage commitments in the reserve-based credit facility are The Royal Bank of Scotland plc (26.84%), Wells Fargo Bank N.A. (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 August 8, 2012, our borrowing base was $90.0 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, using, among other things, the oil and natural gas prices prevailing at such time. 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 August 8, 2012, no letters of credit were 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. A change of control is generally defined as the occurrence of both of the following events (i) wholly owned subsidiaries of Constellation Energy Group, Inc. are the owner of 20% or less of an interest in us (which has now occurred) and (ii) any person or group of persons acting in concert are the owner of more than 35% of an interest in us. 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.

The reserve-based credit facility limits our ability to pay distributions to unitholders. 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 June 30, 2012, 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 PostRock s or Exelon s ownership in us.

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At June 30, 2012, 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, 2012, our actual Total Net Debt to annual Adjusted EBITDA ratio was 2.1 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 1.5 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 7.3 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 our borrowing base, as determined by our lenders, to a level that is below our outstanding debt. If it becomes necessary to reduce debt by amounts that exceed our operating cash flows, we could reduce capital expenditures, suspend our quarterly distributions to unitholders, sell oil and natural gas properties, liquidate in-the-money derivative positions, 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 $87.0 million of the $88.4 million outstanding on our reserve-based credit facility at August 8, 2012. These positions are outlined below in Cash Flow From Operations-Open Commodity Hedge Positions .

Cash Flow from Operations

Our net cash flow provided by operating activities for the six months ended June 30, 2012 was $5.4 million, compared to net cash flow provided by operating activities of $60.1 million for the same period in 2011. This decrease in operating cash flow was primarily attributable to the impact of lower reported oil and natural gas sales revenues of $60.1 million. This decrease in oil and natural gas sales is a result of $48.3 million in lower cash hedge settlements as a result of our hedge restructuring in 2011, $9.0 million from lower market prices for natural gas offset by higher market prices for oil, and $2.8 million as a result of lower production volumes. The decrease in operating cash flows from lower oil and natural gas sales was partially offset by the impact of approximately $2.3 million in lower operating expenses, primarily as a result of lower total spending in both administrative and lease operating expenses and the impact of lower production taxes and cost of sales, and a $2.1 million net change in working capital and other items. The change in our working capital from 2011 to 2012 was attributable to lower accrued liabilities of $4.0 million, lower accounts receivable of $1.6 million, lower royalty payables of $0.5 million, and lower accounts payable of $0.4 million, offset by increased other liabilities of $0.4 million and increased other assets of $0.2 million. Our accrued liabilities decreased after the payments associated with our 2011 incentive compensation programs were made. Our other assets increased as a result of establishing an escrow account for $0.6 million related to a vendor dispute. Our accounts payable increased due to timing of invoice payments. Our receivables balance and our royalty payable balance both decreased due to lower production volumes for our estimated oil and natural gas sales and lower market prices for natural gas. The decrease in prepaid expenses 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 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.

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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 currently post collateral with our counterparties under any of these agreements. This is significant since we are able to lock in 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
2012					2,821,945	$ 5.15	2,740,584	$ 5.22	5,562,529	$ 5.18
2013	2,651,577	$ 5.22	2,254,332	$ 5.57	2,193,682	$ 5.62	2,134,704	$ 5.65	9,234,295	$ 5.50
2014	2,082,454	$ 5.31	2,031,497	$ 5.36	1,978,427	$ 5.41	1,929,652	$ 5.45	8,022,030	$ 5.38
									22,818,854	

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 $
2012					1,680,023	$ 0.54	1,462,286	$ 0.58	3,142,309	$ 0.56
2013	1,402,816	$ 0.39	1,335,077	$ 0.39	1,273,525	$ 0.39	1,223,985	$ 0.39	5,235,403	$ 0.39
2014	1,178,422	$ 0.39	1,133,022	$ 0.39	1,084,270	$ 0.39	1,047,963	$ 0.39	4,443,677	$ 0.39
									12,821,389	

MTM Fixed Price 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
2012					20,151	$ 103.08	25,605	$ 103.88	45,756	$ 103.53
2013	23,937	$ 102.15	22,461	$ 102.13	21,127	$ 102.14	19,902	$ 102.14	87,427	$ 102.14
2014	18,748	$ 100.16	17,685	$ 100.20	16,680	$ 100.25	15,751	$ 100.30	68,864	$ 100.23
2015	14,942	$ 99.73	14,175	$ 99.76	13,469	$ 99.79	12,845	$ 99.81	55,431	$ 99.77
									257,478	

Investing Activities Acquisitions and Capital Expenditures

Cash used in investing activities was $5.3 million for the six months ended June 30, 2012, compared to $4.1 million for the same period in 2011. Our cash capital expenditures were $6.9 million in 2012, which primarily consisted of development expenditures in the Cherokee Basin. We have completed 21 net wells and 27 net recompletions during the first six months of 2012 and have 24 net wells and net recompletions in progress. We also sold 14 wells in the Central Kansas Uplift for $1.4 million and $0.1 million in trucks and equipment during the first half of 2012 and received approximately $0.1 million in distributions from an equity affiliate.

Our cash capital expenditures were $4.4 million for the six months ended June 30, 2011, which primarily consisted of development expenditures in the Cherokee Basin and in the Black Warrior Basin. During the first half of 2011, we 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 June 30, 2011. One of the wells in progress was in the Black Warrior Basin and 1 of the wells was 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.

The current 2012 capital budget of $15.0 million to $19.0 million is expected to be sufficient to maintain our production relatively level with our production in 2011. We currently expect that any future capital expenditures will continue to be funded using our cash flow from operations. We currently expect to focus a significant part of our 2012 capital budget on higher return oil opportunities and capital efficient recompletion opportunities. We currently believe that natural gas prices in excess of $6.00 per Mcfe produce rates of return that generally support capital spending on drilling new wells that produce only coalbed methane.

The amount and timing of our capital expenditures is largely discretionary and within our control. If oil or natural gas prices decline to levels below acceptable levels, and the borrowing base under our reserve-based credit facility is 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. These and other matters are outside of our control and could affect the timing of our capital expenditures. Based upon current oil and natural gas price expectations and expected 2012 production levels, we anticipate that our cash flow from operations will meet any planned capital expenditures and other cash requirements for the next twelve months. We also would have access to any available borrowing capacity under our reserve-based credit facility if additional funds are needed. 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 our operations and other capital resources will provide cash in sufficient amounts during 2012 to maintain our planned levels of capital expenditures, to maintain the outstanding debt level under our reserve-based credit facility, or to commence, maintain or increase any quarterly distribution to unitholders. 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 by financing activities was $10.2 million for the six months ended June 30, 2012, compared to $50.5 million used by financing activities for the same period in 2011. During the first six months of 2012, we used $10.0 million of our existing cash balance to reduce our outstanding debt level to $88.4 million. We also used $0.2 million to fund the cost of units tendered by employees for tax withholdings for unit-based compensation. We suspended our $0.13 per unit quarterly distributions to unitholders for the quarter ended June 30, 2009, through the quarter ended June 30, 2012, to reduce our outstanding indebtedness. For additional information on our distribution, refer below to Outlook.

Our net cash used by financing activities was $50.5 million for the six months ended June 30, 2011. During the first six months of 2011, we used $49.5 million in operating cash flows to reduce our outstanding debt level, including $41.3 million in one-time 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. 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, 2012, and 2011, we had approximately $1.8 million and $3.0 million, respectively, in debt issue costs remaining to be amortized through November 2013.

Contractual Obligations

At June 30, 2012, we had the following contractual obligations or commercial commitments:

	Payments Due By Year[(1)(2)] (in thousands)					
	2012	2013	2014	2015	Thereafter	Total
Reserve-Based Credit Facility	$	$ 88,400	$	$	$	$ 88,400
Support Services Agreement	489					489
Offices Leases	424	408	422	451	301	2,006
Total	$ 913	$ 88,808	$ 422	$ 451	$ 301	$ 90,895

(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 6.0% at June 30, 2012.

At June 30, 2012, our asset retirement obligation was approximately $14.5 million.

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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 8, 2012, 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 $4.0 million in purchases through December 31, 2013. As of August 8, 2012, 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 8, 2012, 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 30, 2012. As of August 8, 2012, 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 8, 2012, we have no past due receivables from J.P. Morgan Ventures Energy Corporation.

Derivative Counterparties

As of August 8, 2012, all of our derivatives are with The Royal Bank of Scotland plc, Societe Generale, The Bank of Nova Scotia, ING Capital Markets LLC, and Wells Fargo Bank, N.A. These derivative counterparties are lenders, or affiliated with a lender, in our reserve-based credit facility. All of our derivatives are currently collateralized by the assets securing our reserve-based credit facility and therefore currently do not require the posting of cash collateral. As of August 8, 2012, each of these financial institutions has an investment grade credit rating. The Royal Bank of Scotland plc, and 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 8, 2012, the banks and their percentage commitments in our reserve-based credit facility are: The Royal Bank of Scotland plc (26.84%), Wells Fargo Bank N.A. (21.95%), The Bank of Nova Scotia (21.95%), ING Capital LLC (14.63%), and Societe Generale (14.63%). As of August 8, 2012, each of these financial institutions has an investment grade credit rating.

Outlook

During 2012, we expect that our business will continue to be affected by the factors described in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2011, 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 2012 Expected Results

Our 2012 business plan and forecast is focused on prioritizing oil production in the execution of our capital program, actively managing our operating expenses and maintaining a debt balance relative to our existing borrowing base of our reserve-based credit facility. 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.

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For 2012, we currently anticipate:

- Our production to be between 13.3 Bcfe and 14.1 Bcfe, approximately 78% 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 $42.5 million to $46.0 million.
- Our Adjusted EBITDA to be in a range of $29.5 million to $31.5 million.
- Our total capital expenditures to be between $15.0 million to $19.0 million. We expect to drill and recomplete wells primarily in the Cherokee Basin. 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, emphasizing oil opportunities to the extent available in the Cherokee Basin.
- Our operating cash flows to be sufficient to allow us to maintain our outstanding debt level relative to our existing borrowing base of $90.0 million.
- The timing of any reinstatement of a quarterly distribution to our unitholders is uncertain at this time. The decision to reinstate any future quarterly distributions will consider, among other things, our outstanding borrowings and the borrowing base under our reserve-based credit facility and cash reserves that are set by our board of managers for the proper conduct of our business. Some of the additional factors that could influence this decision include the renewal or replacement of our reserve-based credit facility and the level of commodity prices at that time. All future quarterly distributions must be approved by our board of managers.
- We will continue to look for opportunities to lower operating costs, with a goal of further reducing our structural general and administrative costs by approximately 25% over the next 12 to 18 months.
- At the present time, we are actively pursuing merger and acquisition opportunities that could lead to enhanced unitholder value.

Impact of 2012 Plan

Our 2012 operating plan is intended to generate operating cash flows to make sufficient capital expenditures for our 2012 production to remain relatively level with our 2011 production. The timing of any reinstatement of a quarterly distribution to our unitholders is uncertain at this time. We expect that this plan will maintain or improve our operational performance and our liquidity position. Achievement of the objectives in this plan would allow us the ability to grow our business by making additional incremental accretive acquisitions of oil and natural gas properties. We will look for additional opportunities to create long-term value and to generate stable cash flows thereby allowing us to make quarterly distributions to our unitholders.

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, 2012, 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, 2011, which was filed on March 1, 2012. The policies disclosed included the accounting for oil 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 Issued But Not Yet Adopted

As of June 30, 2012, 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.

In December 2011, the FASB issued ASU No. 2011-11, *Disclosures about Offsetting Assets and Liabilities,* which requires additional disclosures for financial and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, regardless of whether they are offset

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in accordance with either ASC 210-20-45 or ASC 815-10-45. The guidance is effective beginning on or after January 1, 2013, and will primarily impact the disclosures associated with our commodity and interest rate derivatives. We do not expect this guidance to have any impact on our consolidated financial position, results of operations or cash flows.

New Accounting Pronouncements

In June 2011, the FASB issued ASU 2011-05, *Comprehensive Income (Topic 220)* 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 was eliminated. In December 2011, the FASB issued new authoritative accounting guidance which effectively deferred the requirement to present the reclassification adjustments on the face of the financial statements. The amended guidance was effective for us in the first quarter of 2012 and implementation of this guidance did 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. The amended guidance was effective for us in the first quarter of 2012 and implementation of this guidance did not have a material impact on our financial statements or our disclosures.

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 about 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 continues to show signs of improvement, 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, the U.S. had a warmer than normal winter, production from shale gas plays has increased the supply of natural gas 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 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 or in the event of further reductions in credit availability by banks due to stress in the financial markets, including as a result of the debt crisis in Europe. We have suspended our cash distribution since June 2009 and lowered our maintenance capital spending in 2009, 2010, and 2011. This lower maintenance capital spending has resulted in declining production which lowered our future operating cash flows. We currently expect that our 2012 capital expenditures will be sufficient to maintain our production relatively level with our production in 2011. Until natural gas prices show signs of a sustained recovery, we anticipate that the majority of our capital spending will be focused on any oil opportunities in our existing asset base as well as our most capital efficient recompletion opportunities. 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 potential reinstatement of our distributions to unitholders.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas 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 natural gas 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 Pipe Line (Texas, Oklahoma) and Southern Star Central Gas Pipeline (Texas, Oklahoma, Kansas) with respect to our natural gas properties in the Cherokee Basin, the Inside FERC price for the CenterPoint Energy Gas Transmission (East) for our natural gas 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

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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, any potential distributions to unitholders, or further debt reduction, if warranted. 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, or affiliated with a lender, 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 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 risk 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, 2012	$ 41,176	$ 31,213	$ (9,963)	$ 51,139	$ 9,963

Interest Rate Risk

At June 30, 2012, the one-month LIBOR rate was 0.246%, the three-month LIBOR rate was 0.461%, and our applicable margin on LIBOR borrowings was 3.50%. At June 30, 2012, the ABR rate was 3.25%, and our applicable margin on ABR borrowings was 2.50%. At June 30, 2012, we had debt outstanding of $88.4 million. This entire amount incurred interest at a one-month LIBOR rate plus an applicable margin of 3.50% based on utilization. We had no debt outstanding at the three-month LIBOR or ABR rates. At June 30, 2012, the carrying value and fair value of our debt is $88.4 million.

As of August 8, 2012, the borrowing base under our reserve-based credit facility was $90.0 million and we had $88.4 million of debt outstanding. As a result, the applicable margin on our outstanding borrowings is 3.50% based on utilitization as of August 8, 2012.

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

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Increase	Fair Value	(Decrease)
			(in 000 s)		
Impact of changes in LIBOR on derivative interest rate instruments at June 30, 2012	$ (4,200)	$ (4,023)	$ 177	$ (4,377)	$ (177)

We enter into hedging arrangements to reduce the impact of volatility of changes in the LIBOR interest rate on our interest payments for $87.0 million of our outstanding debt balance of $88.4 million at August 8, 2012. If we reduce our outstanding debt balance to $87.0 million or lower, our cash interest costs for our effective LIBOR rate would begin to approximate the settlements on these interest rate swaps. At August 8, 2012, 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	2.370%
September 20, 2014	$ 31,000	2.520%
October 19, 2014	$ 23,500	2.680%

October 22, 2014	$	7,500	2.610%
November 20, 2014	$	14,000	2.535%

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Item 4. Controls and Procedures

A control system, no matter how well designed 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 June 30, 2012 (the Evaluation Date). Based on such evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that, as of the Evaluation Date, our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and is accumulated and communicated to our management, including our Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

During the six months ended June 30, 2012, 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.

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Part II Other Information

Item 1. Legal Proceedings

Royalty Litigation

On October 28, 2011, Jerry and Betty Wattenbarger and Patricia Webb, individually and as class representatives on behalf of similarly situated persons, filed a Class Action petition in the District Court of Nowata County, Oklahoma against the Company, CEP Mid-Continent, LLC, a subsidiary of the Company, and Newfield Exploration Mid-Continent, Inc., alleging Plaintiffs own oil, gas and mineral interests in lands and wells located in Nowata County, Oklahoma, subject to oil and gas leases owned and operated by Defendants and that Defendants have underpaid royalties due and owing on the true value received or that should have been received by Defendants for production from Plaintiffs mineral interests. Plaintiffs have alleged, among other things, breach of implied covenant to market; breach of express and implied lease obligations; violation of statutory law; breach of duty of good faith and fair dealing and of the duty to act as a reasonably prudent operator; breach of fiduciary duty; constructive fraud and failure to disclose facts surrounding deductions made from royalty payments. Plaintiffs seek certification of a statewide class of plaintiffs, specify that the class claims against the Company and its subsidiary relate to the proper payment for production occurring on or after February 1, 2007, and currently limit damage claims against all Defendants to no more than $75,000 with respect to each Plaintiff and no more than $5 million in the aggregate for the Plaintiffs and the individual putative class members, in each case exclusive of interest and costs, but inclusive of any attorneys fees. On December 1, 2011, the case was removed by Defendants to the United States District Court for the Northern District of Oklahoma, and on December 28, 2011, Defendants filed their answer to Plaintiff s petition.

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, 2011 that was filed with the SEC on March 1, 2012. 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 2011 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.

Tax Risks to Unitholders

The value of an investment in our units could be affected by recent and potential federal tax increases.

Absent new legislation extending existing tax rates, in taxable years beginning after December 31, 2012, the highest marginal United States federal income tax rate applicable to ordinary income and long-term capital gains of individuals will increase to 39.6% and 20%, respectively. These rates are subject to change by new legislation at any time.

The Health Care and Education Reconciliation Act of 2010 included a provision that, in taxable years beginning after December 31, 2012, subjects certain individuals, estates and trusts to an Unearned Income Medicare Contribution tax of 3.8% on certain income. In the case of an individual having a modified adjusted gross income in excess of $200,000 (or $250,000 for married taxpayers filing joint returns), the provision imposes a tax equal to 3.8% of the lesser of such excess and the individual s net investment income, which will include net income and gain from the ownership or disposition of our units.

These recent federal tax increases, and any other future potential federal tax increases, may negatively impact the value of an investment in our common units.

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 a credit facility 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 distributions;
- 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;
- lack of support from a sponsor or a change in sponsor; 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. 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, anticipa estimate, predict, potential, pursue, target, continue, the negative of such terms or other comparable terminology.

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

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

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Item 6. Exhibits

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

1. Financial Statements:

Consolidated Balance Sheets   Constellation Energy Partners LLC at June 30, 2012 and December 31, 2011

Consolidated Statements of Operations and Comprehensive Income/(Loss)   Constellation Energy Partners LLC for the six months ended June 30, 2012 and June 30, 2011

Consolidated Statements of Cash Flows   Constellation Energy Partners LLC for the six months ended June 30, 2012 and June 30, 2011

Consolidated Statements of Changes in Members   Equity   Constellation Energy Partners LLC for the six months ended June 30, 2012

Notes to Consolidated Financial Statements

EXHIBIT INDEX

Exhibit Number	Description
*+10.1.	Amendment to Grant Agreement Relating to 2012 Performance Award Executives (Units)
*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 Label Linkbase Document

* Filed herewith

\+ Management contract or compensatory plan or arrangement.

** Pursuant to Rule 406T of Regulation S-T, the interactive data files on Exhibit 101 hereto are not deemed filed or part of a registration statement or prospectus for purposes of Section 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability under those actions.

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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 9, 2012	By /s/ MICHAEL B. HINEY Michael B. Hiney Chief Accounting Officer and Controller