EATON VANCE SENIOR FLOATING RATE TRUST
Form SC TO-C
July 09, 2018

AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON JULY 9, 2018

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

SCHEDULE TO

Tender Offer Statement Under Section 14(D)(1) or 13(E)(1) of the

Securities Exchange Act Of 1934

Eaton Vance Senior Floating-Rate Trust

(Name of Subject Company (Issuer))

Eaton Vance Senior Floating-Rate Trust

(Name of Filing Person (Issuer))

Auction Preferred Shares Series A, B, C and D, Par Value $0.01 Per Share

(Title of Class of Securities)

Series A – 27828Q204

Series B – 27828Q303

Series C – 27828Q402

Series D – 27828Q501

(CUSIP Number of Class of Securities)

Maureen A. Gemma, Esquire

Eaton Vance Management

Two International Place

Boston, Massachusetts 02110

(617) 482-8260

(Name, Address and Telephone Number of Person Authorized to Receive Notices

and Communications on Behalf of the Person(s) Filing Statement)

Transaction Valuation*	**Amount Of Filing Fee***
Not Applicable	Not Applicable

* No Filing fee is required because this filing includes only preliminary communications made before the commencement of a tender offer.

[_] Check the box if any part of the fee is offset as provided by Rule 0-11(a)(2) and identify the filing with which the offsetting fee was previously paid. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

Amount Previously Paid:	Not Applicable	Filing Party:	Not Applicable
Form of Registration No.:	Not Applicable	Date Filed:	Not Applicable

[x] Check the box if the filing relates solely to preliminary communications made before the commencement of a tender offer.

Check the appropriate boxes below to designate any transactions to which the statement relates:

[_]	third party tender offer subject to Rule 14d-1.
[x]	issuer tender offer subject to Rule 13e-4.
[_]	going-private transaction subject to Rule 13e-3.
[_]	amendment to Schedule 13D under Rule 13d-2.

Check the following box if the filing is a final amendment reporting the results of the tender offer. [_]

Items 1-11.

Not Applicable.

Item 12. Exhibits.

Exhibit No.	Document
99.1	Press release issued by the Fund dated June 29, 2018

Item 13.

Not Applicable.

Exhibit Index

<u>Exhibit No.</u> **<u>Document</u>**

99.1 Press Release issued by the Fund dated June 29, 2018

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"bottom"> **Percentage of**
Total Units
Beneficially
Owned

Name of Beneficial Owner	**Number**	**Percentage**	**Number**	**Percentage**	**Percentage**
PostRock Energy Corporation(1)	5,918,894	20.8%	484,505	30%	21.3%
Sanchez Energy Partners I, LP(2)	4,724,407	16.6%	1,130,512	70%	19.5%
Bradley Louis Radoff(3)	2,360,000	8.3%			7.8%
Richard H. Bachmann	60,612	*			*
Stephen R. Brunner	738,007	2.6%			2.5%
Elizabeth A. Crawford	19,495	*			*

Michael B. Hiney(4)					
95,251	*			*	
Richard S. Langdon					
40,100	*			*	
Lisa J. Mellencamp(4)					
193,975	*			*	
Antonio R. Sanchez, III(2)					
4,724,407	16.6%	1,130,512	70%	19.5%	
John N. Seitz					
51,612	*			*	
Charles C. Ward					
328,722	1.2%			1.1%	
Gerald F. Willinger					
All managers and executive officers as a group (8 persons)					
1,238,548	4.4%			4.1%	

* Less than 1%

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(1) Ownership data as reported on Schedule 13D/A filed on July 29, 2013, by PostRock Energy Corporation, White Deer Energy L.P., White Deer Energy TE L.P., White Deer Energy FI L.P., Edelman & Guill Energy L.P., Edelman & Guill Energy Ltd., Thomas J. Edelman, and Ben A. Guill. PostRock Energy Corporation, through its direct ownership of CEPM may be deemed to beneficially own the Class B common units and Class A units held by CEPM. The address of PostRock Energy Corporation and CEPM is 210 Park Avenue, Oklahoma City, Oklahoma 73102. The address of the other entities reported is White Deer Energy L.P., 667 Madison Avenue, 4th Floor, New York, New York 10065.

(2) Ownership data as reported on Form 3 on August 13, 2013 and Schedule 13D on August 19, 2013 by Sanchez Energy Partners I, LP, SEP Management I, LLC, Sanchez Oil & Gas Corporation, A. R. Sanchez, Jr. and Antonio R. Sanchez, III. These securities are owned directly by Sanchez Energy Partners I, LP., which is controlled by its general partner, SEP Management I, LLC, a wholly-owned subsidiary of Sanchez Oil & Gas Corporation. Sanchez Oil & Gas Corporation is managed by A.R. Sanchez, Jr. and Antonio R. Sanchez, III. Each of SEP Management I, LLC, Sanchez Oil & Gas Corporation, A. R. Sanchez, Jr. and Antonio R. Sanchez, III may be deemed to share voting and dispositive power over the units held by Sanchez Energy Partners I, LP. Each of SEP Management I, LLC, Sanchez Oil & Gas Corporation, A. R. Sanchez, Jr. and Antonio R. Sanchez, III disclaims beneficial ownership of these securities except to the extent of such person s pecuniary interest therein.

(3) Ownership data as reported on Schedule 13G/A filed on February 14, 2014 by Bradley Louis Radoff. The address of Mr. Radoff is 1177 West Loop South, Suite 1625, Houston, Texas 77027. The filing lists 2,360,000 Class B common units owned by Mr. Radoff, who has sole voting power.

(4) Ms. Mellencamp resigned as an executive officer in January 2013, and Mr. Hiney resigned as an executive officer in May 2013.

Equity Compensation Plan Information

The following table reflects our equity compensation plan information for our Long-Term Incentive Plan and our 2009 Omnibus Incentive Compensation Plan as of December 31, 2013:

	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	Number of securities remaining available for future issuance under equity compensation plans
Plan Category			
Equity compensation plans approved by security holders(a)		$	386,600
Equity compensation plans not approved by security holders		$	
Total		$	386,600

(a) As of April 15, 2013, the number of securities remaining available for future issuance under our Long-Term Incentive Plan was 102,398 and the number remaining available under our 2009 Omnibus Incentive Plan was 281,252.

Item 13. Certain Relationships and Related Transactions, and Manager Independence

PostRock, Exelon and SOG, through subsidiaries, own a number of our units. As of December 31, 2013, CEPM , a subsidiary of PostRock, owned 484,505 of our Class A units and 5,918,894 of our Class B common units. CE PH, a subsidiary of Exelon, owned all of our Class C management incentive interests and all of our Class D interests. SEP I, a subsidiary of SOG, owned 1,130,512 of our Class A units, 4,724,407 of our Class B common units and one Class Z unit.

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As discussed in Item 10. Managers, Executive Officers and Corporate Governance-Corporate Governance-Committees of the Board of Managers Conflicts Committee , either our board of managers or the board s conflicts committee reviews all related person transactions.

Our board of managers has established a conflicts committee to review specific matters that the board believes may involve conflicts of interest, including transactions with related persons such as PostRock, Exelon and SOG or their affiliates, including CEPM, CEPH and SEP I. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to our Company. Our operating agreement provides that members of the conflicts committee may not be officers or employees of our Company, or directors, officers or employees of any of our affiliates, and must meet the independence standards for service on an audit committee of a board of directors as established by NYSE MKT and SEC rules. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to our Company and approved by all of our unitholders. Our board is not required by the terms of our operating agreement to submit the resolution of a potential conflict of interest to the conflicts committee, and may itself resolve such conflict of interest if the board determines that (i) the terms of the related person transaction are no less favorable to us than those generally being provided to or available from unrelated third parties or (ii) the transaction is fair and reasonable to us, taking into account the totality of the relationships between the parties involved. Any matters approved by the board in this manner will be deemed approved by all of our unitholders. For 2012 and 2013, there were no related party transactions with PostRock, Exelon and SOG or their affiliates that were reviewed or required to be reviewed by the conflicts committee.

PostRock as an Interested Unitholder

In 2011, PostRock acquired certain of our Class A units and Class B common units in two separate transactions which represented a 21.3% ownership interest in us at December 31, 2013. Approval of the purchase of these units was neither required nor given by our board of managers or conflicts committee. We believe PostRock is now an interested unitholder under Section 203 of the Delaware General Corporation Law, which is applicable to us pursuant to our operating agreement. Section 203, as it applies to us, prohibits an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in business combinations with us for three years following the time such person becomes an interested unitholder without the approval of our board of managers and the vote of 66⅔% of our outstanding Class B common units, excluding those held by the interested unitholder. Section 203 broadly defines business combination to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. In addition to limiting our ability to enter into transactions with PostRock or its affiliates, this provision of our operating agreement could have an anti-takeover effect with respect to transactions not approved in advance by our board of managers, including discouraging takeover attempts that might result in a premium over the market price for our common units. We believe the Section 203 restrictions related to these unit purchases expire in December 2014.

SOG

In August 2013, SOG acquired certain of our Class A units and Class B common units and one Class Z unit in one transaction which represented a 19.5% ownership interest in us at December 31, 2013. These units were issued to SOG, along with cash, in exchange for oil and natural gas properties located in Texas and Louisiana.

In August 2013, the Company also entered into a Registration Rights Agreement with SOG pursuant to which the Company granted to SOG certain registration rights related to the unit consideration thereunder. Under the Registration Rights Agreement, the Company granted SOG demand registration rights with respect to the preparation and filing with the SEC of one or more registration statements for the purpose of registering the resale of the securities that will be registered.

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Board Independence

A majority of our managers are required to be independent in accordance with NYSE MKT listing standards. For a manager to be considered independent, the board of managers must affirmatively determine that such manager has no material relationship with us. When assessing the materiality of a manager s relationship with us, the board of managers considers the issue from both the standpoint of the manager and from that of persons and organizations with whom or with which the manager has an affiliation. The board of managers has adopted standards to assist it in determining if a manager is independent. A manager will be deemed to have a material relationship with us and will not be deemed to be an independent manager if;

- the manager has been an employee (other than as an interim executive officer for less than one year), or an immediate family member of the manager has been an executive officer, of us at any time during the past three years:

- the manager has received, or an immediate family member of the manager has received, more than $120,000 in any twelve-month period in direct compensation from us, other than manager and committee fees or other forms of deferred compensation for priors service (provided such compensation is not contingent in any way on continued service), at any time during the past three years;

- the manager has been a partner of or employed by, or an immediate family member of the manager has been a partner of or employed by, our internal or external auditor at any time during the past three years;

- the manager has been employed, or an immediate family member of the manager has been employed, as an executive officer of another company where any of our present executives serve on that company s compensation committee at any time during the past three years; or

- the manager has been an executive officer or an employee, or an immediate family member of the manager has been an executive officer, of a company that makes payments to, or receives payments from us for property or services in an amount that, in any single fiscal year, exceeds the greater of $200,000, or 5% of such other company s consolidated gross revenues, at any time during the past three years.

An immediate family member includes a person s spouse, parents, children, siblings, mothers- and fathers-in-law, sons- and daughters-in-law, brothers- and sisters-in-law, and anyone (other than domestic employees) who resides in said person s home.

The board of managers has determined that each of Messrs. Bachmann, Langdon and Seitz is independent under the NYSE MKT listing standards. In addition, the audit, compensation and nominating and corporate governance committees are composed entirely of independent managers in accordance with NYSE MKT listing standards, SEC requirements and other applicable laws, rules and regulations. There are no transactions, relationships or other arrangements between us and our independent managers that need to be considered under the NYSE MKT listing standards in determining that such persons are independent.

Item 14. Principal Accounting Fees and Services

We engaged our principal accountant, KPMG LLP (KPMG) , to audit our financial statements and perform other professional services beginning in the fiscal year ended December 31, 2013. Prior to the engaging of KPMG, our principal accountant was PricewaterhouseCoopers LLP. PricewaterhouseCoopers LLP, audited our financial statements and performed other professional services for the fiscal year ended December 31, 2012.

Audit Fees. The aggregate fees billed for the financial statement audit or services provided in connection with statutory or regulatory filings for the years ended 2013 and 2012 were $600 ,000 and $804,201, respectively.

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Audit-Related Fees. There have been no audit-related fees billed by KPMG for the year ended 2013. The re were no aggregate audit-related fees billed by PricewaterhouseCoopers LLP for the year ended 2012.

Tax Fees. There were no tax fees billed by KPMG for the year ended 2013. The aggregate fees related to the preparation of K-1 statements and tax services for the year ended 2012 were $381,390, billed by PricewaterhouseCoopers LLP.

All Other Fees. The re were no other fees billed by our principal accountant for the years ended 2013 and 2012.

Audit Committee Pre-Approval Policies and Practices

Our audit committee must pre-approve any audit and permissible non-audit services performed by our independent registered public accounting firm. In addition, the audit committee has oversight responsibility to ensure the independent registered public accounting firm is not engaged to perform certain enumerated non-audit services, including but not limited to bookkeeping, financial information system design and implementation, appraisal or valuation services, internal audit outsourcing services and legal services. The audit committee has adopted an audit and non-audit services pre-approval policy, which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent registered public accounting firm must be approved. Pursuant to the policy, all services must be reviewed and approved and the chairman of the audit committee has been delegated the authority to specifically pre-approve services, which pre-approval is subsequently reviewed with the committee. All of the services described as Audit-Related Fees, Tax Fees and All Other Fees were approved by the audit committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

1. Financial Statements:

Report of Independent Registered Public Accounting Firm dated March 27, 2014 of KPMG LLP

Report of Independent Registered Public Accounting Firm dated March 8, 2013 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Loss Constellation Energy Partners LLC for the two years ended December 31, 2013

Consolidated Balance Sheets Constellation Energy Partners LLC at December 31, 2013 and December 31, 2012

Consolidated Statements of Cash Flows Constellation Energy Partners LLC for the two years ended December 31, 2013

Consolidated Statements of Changes in Members Equity Constellation Energy Partners LLC for the two years ended December 31, 2013

Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

Schedules are omitted as not applicable or not required

3. Exhibits Required by Item 601 of Regulation S-K.

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Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.2	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC, Kansas Production EQR, LLC and Kansas Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.3	Agreement of Merger, dated as of July 12, 2007, among AMVEST Osage, Inc., AMVEST Oil & Gas, Inc. and CEP Mid-Continent LLC, f/k/a CEP Cherokee Basin LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).
2.4	Purchase and Sale Agreement, dated as of August 2, 2007, between Newfield Exploration Mid-Continent Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).
2.5	Nominee Agreement, dated as of September 21, 2007, by and between Newfield Exploration Mid-Continent Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
2.6	Asset Purchase and Sale Agreement, dated as of May 12, 2005, by and among Everlast Energy LLC, RB Marketing Company LLC, Robinson s Bend Operating Company LLC and CBM Equity IV, LLC (incorporated herein by reference to Exhibit 10.9 to Amendment No. 2 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on September 29, 2006.
2.7	Agreement for Purchase and Sale, dated as of February 19, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.8	First Amendment to Agreement for Purchase and Sale, dated as of March 31, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.9	Oil and Gas Purchase Contract, dated as of October 1, 1993, by and between Torch Energy Marketing, Inc. and Torch Royalty Company (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2 to the Registration Statement on Form S-1 filed by Constellation Energy Partners LLC on June 29, 2006, File No. 333-134995).
2.1	Membership Interest Purchase and Sale Agreement, dated February 1, 2013 between Constellation Energy Partners LLC and Constellation Commodities Upstream LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report and Form 8-K filed by Constellation Energy Partners LLC on February 4, 2013, File No. 001-33147).
2.11	

Contribution Agreement, dated as of August 9, 2013, by and between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K field by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).

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Exhibit Number	Description
3.1	Certificate of Formation of Constellation Energy Partners LLC, as amended (incorporated herein by reference to Exhibit 3.1 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 12, 2007, File No. 001-33147).
3.2	Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
3.3	Amendment No. 1 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of April 23, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
3.4	Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of July 25, 2007. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).
3.5	Amendment No. 3 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of September 21, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).
3.6	Amendment No. 4 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of December 28, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on December 28, 2007, File No. 001-33147).
3.7	Amendment No. 5 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of August 9, 2013 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).
10.1	Second Amended and Restated Credit Agreement dated as of May 30, 2013, among Constellation Energy Partners LLC, as borrower, Societe Generale, as administrative agent, and the lenders party hereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 31, 2013, File No. 001-33147).
10.2	Trademark License Agreement, dated as of November 20, 2006, by and among Constellation Energy Group, Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
10.3	Exploration and Development Agreement, dated July 25, 2005, by and between The Osage Nation and AMVEST Osage, Inc. (incorporated herein by reference to Exhibit 10.23 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.4	Substituted and Replaced First Amendment to the Exploration and Development Agreement, dated October 18, 2006, by and between The Osage Nation and AMVEST Osage, Inc. (incorporated herein by reference to Exhibit 10.24 to the Annual Report on Form 10-K filed by Constellation Energy

	Partners LLC on February 27, 2009, File No. 001-33147).
10.5	Assignment, Assumption and Ratification Agreement, dated as of July 25, 2007, by and between AMVEST Osage, Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 10.25 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).

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Exhibit Number	Description
10.6	Water Gathering and Disposal Agreement, dated as of August 9, 1990, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.17 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.7	First Amendment to Water Gathering and Disposal Agreement, dated as of October 1, 1993, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.18 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.8	Second Amendment to Water Gathering and Disposal Agreement, dated as of November 30, 2004, by and between Robinson s Bend Operating Company, LLC and Everlast Energy LLC (incorporated herein by reference to Exhibit 10.19 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.9	Third Amendment, dated June 13, 2011, to Water Gathering and Disposal Agreement dated November 30, 2004, by and between Robinson s Bend Operating II, LLC, Robinson s Bend Production II, LLC and Torch Energy Associates Ltd. (incorporated herein by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 15, 2011, File No. 001-33147).
10.1	Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Stephen R. Brunner (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).
10.11	Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Charles C. Ward (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).
10.12	Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Lisa J. Mellencamp (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).
10.13	Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Michael B. Hiney (incorporated herein by reference to Exhibit 10.4 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).
10.14	Employment Agreement, dated as of February 15, 2013, between Elizabeth Ann Evans and CEP Services Company, Inc. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on February 19, 2013, File No. 001-33147).
10.15	Constellation Energy Partners LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 20, 2006, File No. 001-33147).
10.16	Constellation Energy Partners LLC 2009 Omnibus Incentive Compensation Plan (incorporated herein by reference to Exhibit A to the Proxy Statement filed by Constellation Energy Partners LLC on

October 22, 2009, File No. 001-33147).

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Exhibit Number	Description
10.17	Form of Grant Agreement Relating to Notional Units with DERs Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.9 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 4, 2009, File No. 001-33147).
10.18	Form of Grant Agreement Relating to Notional Units with DERs Independent Managers (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.10 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 4, 2009, File No. 001-33147).
10.19	Form of Grant Agreement Relating to Restricted Units Executives (under the 2009 Omnibus Incentive Compensation Plan incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on March 3, 2010, File No. 001-33147).
+10.20	Form of Amended and Restated Grant Agreement Relating to Unit-Based Awards Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on August 5, 2011, File No. 001-33147).
+10.21	Amendment to Amended and Restated Grant Agreement Relating to Unit-Based Awards-Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on May 10, 2012, File No. 001-33147).
+10.22	Form of Grant Agreement Relating to Restricted Units Independent Managers (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.30 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 25, 2010, File No. 001-33147).
+10.23	Registration Rights Agreement, dated as of August 9, 2013, between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).
*21.1	List of subsidiaries of Constellation Energy Partners LLC.
*23.1	Consent of KPMG LLP.
*23.2	Consent of PricewaterhouseCoopers LLP.
*23.3	Consent of Netherland, Sewell & Associates, Inc.
*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.
*99.1	Report of Netherland, Sewell & Associates, Inc.

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Exhibit Number	Description
*101.INS	XRBL Instance Document
*101.SCH	XRBL Schema Document
*101.CAL	XRBL Calculation Linkbase Document
*101.LAB	XRBL Label Linkbase Document
*101.PRE	XRBL Presentation Linkbase Document
*101.DEF	XRBL Definition Linkbase Document

* Filed herewith
\+ Management contract or compensatory plan or arrangement.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders and Board of Managers of Constellation Energy Partners LLC:

We have audited the accompanying consolidated balance sheet of Constellation Energy Partners LLC and subsidiaries as of December 31, 2013, and the related consolidated statements of operations and comprehensive loss, members equity, and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit. The accompanying consolidated financial statements of Constellation Energy Partners LLC and subsidiaries as of December 31, 2012, were audited by other auditors whose report thereon dated March 8, 2013, expressed an unqualified opinion on those statements, before the discontinued operations adjustments described in Note 2 to the consolidated financial statements.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the 2013 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Constellation Energy Partners LLC and subsidiaries as of December 31, 2013, and the results of their operations and their cash flows for the year then ended in conformity with U.S. generally accepted accounting principles.

We also have audited the adjustments described in Note 2 that were applied to retrospectively adjust the 2012 consolidated financial statements for discontinued operations. In our opinion, such adjustments are appropriate and have been properly applied. We were not engaged to audit, review, or apply any procedures to the 2012 consolidated financial statements of the Company other than with respect to the adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2012 consolidated financial statements taken as a whole.

/s/ KPMG LLP

Houston, Texas

March 27, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders and Board of Managers of Constellation Energy Partners LLC:

In our opinion, the consolidated balance sheets as of December 31, 2012 and the related consolidated statements of operations and comprehensive income (loss), of cash flows and of changes in members equity for the year then ended, before the effects of the adjustments to retrospectively reflect the discontinued operations described in Note 2, present fairly, in all material respects, the financial position of Constellation Energy Partners LLC and its subsidiaries at December 31, 2012, and the results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America (the 2012 financial statements before the effects of the adjustments discussed in Note 2 are not presented herein). These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit, before the effects of the adjustments described above, of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

Subsequent to December 31, 2012, the Company entered into an asset sale transaction and extended its reserve based credit facility to March 31, 2014.

We were not engaged to audit, review, or apply any procedures to the adjustments to retrospectively reflect the discontinued operations described in Note 2 and accordingly, we do not express an opinion or any other form of assurance about whether such adjustments are appropriate and have properly applied. Those adjustments were audited by other auditors

/s/ PricewaterhouseCoopers LLP

Houston, Texas

March 8, 2013

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Loss

(In thousands, except per unit data)

	Year Ended December 31, 2013	2012
Revenues		
Natural gas sales	$ 23,129	$ 34,019
Oil and liquid sales	20,948	12,508
Total revenues	44,077	46,527
Expenses:		
Operating expenses:		
Lease operating expenses	18,858	19,411
Cost of sales	1,455	1,299
Production taxes	2,601	1,646
General and administrative	22,214	15,747
Loss on sale of assets	4	7
Depreciation, depletion and amortization	18,972	11,732
Asset impairments (See Note 7)	2,357	109
Accretion expense	519	459
Total operating expenses	66,980	50,410
Other expense / (income)		
Interest expense	3,150	5,734
Other income	(196)	(155)
Total other expenses	2,954	5,579
Total expenses	69,934	55,989
Loss from continuing operations	(25,857)	(9,462)
Loss from discontinued operations	(2,686)	(77,081)
Net loss	$ (28,543)	$ (86,543)
Change in fair value of commodity hedges		202
Cash settlement of commodity hedges		(5,639)
Other comprehensive loss		(5,437)
Comprehensive loss	$ (28,543)	$ (91,980)
Loss per unit (See Note 1)		

Loss from continuing operations per unit				
Class A units Basic and diluted	$	(0.55)	$	(0.39)
Class B units Basic and diluted	$	(1.01)	$	(0.39)
Discontinued operations per unit				
Class A units Basic and diluted	$	(0.06)	$	(3.19)
Class B units Basic and diluted	$	(0.10)	$	(3.19)
Net loss per unit				
Class A units Basic and diluted	$	(0.61)	$	(3.58)
Class B units Basic and diluted	$	(1.11)	$	(3.58)
Weighted Average Units Outstanding				
Class A units Basic and diluted		933,613		483,564
Class B units Basic and diluted		25,210,106		23,687,946
Distributions declared and paid per unit	$		$	

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

(In thousands, except unit data)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 4,894	$ 1,959
Accounts receivable	6,678	5,615
Prepaid expenses	2,547	1,309
Risk management assets (See Note 5)	9,141	17,965
Current assets from discontinued operations		1,886
Total current assets	23,260	28,734
Oil and natural gas properties (See Note 7)		
Oil and natural gas properties, equipment and facilities	639,156	594,020
Material and supplies	1,054	771
Less accumulated depreciation, depletion, amortization, and impairments	(495,215)	(474,669)
Net oil and natural gas properties	144,995	120,122
Other assets		
Debt issue costs (net of accumulated amortization of $9,003 and $7,775, respectively)	824	1,168
Risk management assets (See Note 5)	1,461	7,431
Restricted cash	1,748	600
Other non-current assets	2,245	2,594
Long-term assets from discontinued operations		67,373
Total assets	$ 174,533	$ 228,022
LIABILITIES AND MEMBERS EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 12	$ 480
Accrued liabilities	12,763	7,174
Royalty payable	1,242	1,418
Risk management liabilities (See Note 5)		523
Debt (See Note 6)		50,000
Current liabilities from discontinued operations		1,578
Total current liabilities	14,017	61,173
Other liabilities		
Asset retirement obligation	9,513	7,665

Risk management liabilities (See Note 5)				637
Other non-current liabilities		1,398		589
Debt (See Note 6)		50,700		34,000
Other long-term liabilities from discontinued operations				7,692
Total other liabilities		61,611		50,583
Total liabilities		75,628		111,756
Commitments and contingencies (See Note 10)				
Members equity				
Class A units, 1,615,017 and 483,418 units authorized, issued and outstanding at December 31, 2013 and 2012, respectively		2,591		2,326
Class B units, 28,848,785 and 24,124,378 units authorized, and 28,462,185 and 23,687,507 issued and outstanding at December 31, 2013 and 2012, respectively		96,314		113,940
Total members equity		98,905		116,266
Total liabilities and members equity	$	174,533	$	228,022

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Cash Flows

(In thousands)

	Year Ended December 31, 2013	2012
Cash flows from operating activities:		
Net loss	$ (28,543)	$ (86,543)
Adjustments to reconcile net loss to cash provided by operating activities:		
Depreciation, depletion and amortization	18,972	11,732
Asset impairments (See Note 7)	2,357	109
Amortization of debt issuance costs	1,289	1,310
Accretion expense	519	459
Equity earnings in affiliate	(271)	(173)
Loss from disposition of property and equipment	4	7
Bad debt expense	44	35
Mark-to-market on derivatives:		
Total gains	1,551	(14,640)
Cash settlements	12,082	22,189
Unit-based compensation programs	1,049	1,497
Discontinued operations	2,686	77,081
Changes in Assets and Liabilities:		
Increase in accounts receivable	(1,106)	(924)
Increase in prepaid expenses	(1,238)	(144)
Decrease in other assets	8	
Decrease in accounts payable	(468)	(370)
Increase (decrease) in accrued liabilities	4,824	(2,446)
Increase (decrease) in royalty payable	(176)	115
Increase in other liabilities	559	493
Net cash provided by continuing operations	14,142	9,787
Net cash provided by discontinued operations	1,062	4,421
Net cash provided by operating activities	15,204	14,208
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash acquired	(20,221)	(252)
Development of natural gas properties	(15,694)	(15,336)
Proceeds from sale of property and equipment	58,987	1,508
Increase in cash held for escrow	(1,148)	(600)
Distributions from equity affiliate	245	230
Net cash provided by (used in) continuing operations	22,169	(14,450)
Net cash used in discontinued operations		(302)

Net cash (used in) investing activities		22,169		(14,752)
Cash flows from financing activities:				
Members distributions				
Proceeds from issuance of debt		16,894		
Repayment of debt		(50,194)		(14,400)
Units tendered by employees for tax withholdings		(185)		(200)
Debt issue costs		(953)		(55)
Net cash used in continuing operations		(34,438)		(14,655)
Net cash used in discontinued operations				
Net cash used in financing activities		(34,438)		(14,655)
Net increase (decrease) in cash		2,935		(15,199)
Cash and cash equivalents, beginning of period		1,959		17,158
Cash and cash equivalents, end of period	$	4,894	$	1,959
Supplemental disclosures of cash flow information:				
Change in accrued capital expenditures	$	(1,674)	$	307
Cash received during the period for interest	$		$	1
Cash paid during the period for interest	$	(1,881)	$	(3,650)
Cash paid during the period for income taxes	$	(75)	$	(19)

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Changes in Members Equity

(In thousands, except unit data)

	Class A		Class B		Accumulated Other Comprehensive	Total Members
	Units	Amount	Units	Amount	Income	Equity
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	(1,845)	(4)	(90,425)	(196)		(200)
Change in fair value of commodity hedges					202	202
Cash settlement of commodity hedges					(5,639)	(5,639)
Unit-based compensation programs	230	31	11,300	1,495		1,526
Net loss		(1,731)		(84,812)		(86,543)
Balance, December 31, 2012	483,418	$ 2,326	23,687,507	$ 113,940	$	$ 116,266
Distributions						
Units tendered by employees for tax withholding	(2,853)	(4)	(139,810)	(181)		(185)
Unit-based compensation programs	3,940	21	190,081	1,028		1,049
Units issued for acquisition of properties	1,130,512	818	4,724,407	9,500		10,318
Net loss		(570)		(27,973)		(28,543)
Balance, December 31, 2013	1,615,017	$ 2,591	28,462,185	$ 96,314	$	$ 98,905

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013 and 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Basis of Presentation

Constellation Energy Partners LLC (CEP, we, us, our or the Company) was organized as a limited liability company on February 7, 2005, under 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, PostRock Energy Corporation (NASDAQ: PSTR) (PostRock), Exelon Corporation (NYSE: EXC) (Exelon) and Sanchez Oil & Gas Corporation (SOG) own a portion of our outstanding units. As of December 31, 2013, Constellation Energy Partners Management, LLC (CEPM), a subsidiary of PostRock, owned 484,505, or 30%, 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, owned all of our Class C management incentive interests and all of our Class D interests. Sanchez Energy Partners I, LP (SEP I), an affiliate of SOG, owned 1,130,512, or 70%, of our Class A units and 4,724,407 of our Class B common units.

We are currently focused on the acquisition, development and production of oil and natural gas properties, as well as midstream assets. Our proved reserves are located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas and in Texas and Louisiana.

Accounting policies used by us conform to accounting principles generally accepted in the United States of America. 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.

Use of Estimates

Estimates and assumptions are made when preparing financial statements under accounting principles generally accepted in the United States of America. These estimates and assumptions affect various matters, including:

reported amounts of revenue and expenses in the Consolidated Statements of Operations and Other Comprehensive Loss during the reported periods,

reported amounts of assets and liabilities in the Consolidated Balance Sheets at the dates of the financial statements,

- disclosure of quantities of reserves and use of those reserve quantities for depreciation, depletion and amortization, and

- disclosure of contingent assets and liabilities at the date of the financial statements.

These estimates involve judgments with respect to numerous factors that are difficult to predict and are beyond management s control. As a result, changes in facts and circumstances or additional information may result in revised estimates or actual amounts may materially differ from these amounts.

Reclassifications

Certain reclassifications have been made to the prior periods to conform to the current period presentation. These reclassifications had no effect on total assets, total liabilities, total unitholders equity, net income or net cash provided by or used in operating, investing or financing activities.

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Discontinued Operations

In February 2013, we sold all of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama. The related results of operations and cash flows have been classified as discontinued operations in the consolidated statements of operations, balance sheets, statements of cash flows and consolidated financial information. Unless otherwise indicated, information presented in the Notes to Consolidated Financial Statements relates only to the Company s continuing operations. Information related to discontinued operations is included in Note 2. *Discontinued Operations.*

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash equivalents. Checks-in-transit were none in 2013 and $0.6 million in 2012 and are included in accounts payable in our consolidated balance sheets.

Restricted Cash

Restricted cash at December 31, 2013 of $1.7 million is held in escrow in relation to the sale of the Robinson s Bend Field assets and related to litigation involving one of our service providers. Restricted cash at December 31, 2012 was comprised of $0.6 million held in escrow related to litigation involving on e of our service providers.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject us to a concentration of credit risk consist of cash and cash equivalents, accounts receivable and derivative financial instruments. We place our cash with high credit quality financial institutions. We place our derivative financial instruments with financial institutions that participate in our reserve-based credit facility and maintain an investment grade credit rating. Substantially all of our accounts receivables are due from purchasers of oil and natural gas. These sales are generally unsecured and, in some cases, may carry a parent guarantee. As we generally have fewer than 10 large customers for our oil and natural gas sales, we routinely assess the financial strength of our customers. Bad debt expense is recognized on an account-by-account review and when recovery is not probable. Our allowance for doubtful accounts was less than $0.1 million in each of 2012 and 2013. We have no off-balance-sheet credit exposure related to our operations or customers.

For the year ended December 31, 2013, five customers accounted for approximately 22%, 20%, 17%, 14% and 8% of our sales revenues. For the year ended December 31, 2012, five customers accounted for approximately 28%, 10%, 9%, 9% and 8% of our sales revenues.

Oil and Natural Gas Properties

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for our oil and natural gas exploration, development and production activities. Leasehold acquisition costs, property acquisition and the costs of development of proved areas are capitalized. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

Accounting rules require that we price our oil and natural gas proved reserves at the preceding twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. Such SEC-required prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Our proved reserve estimates exclude the effect of any derivatives we have in place.

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Depreciation, Depletion and Amortization

Depreciation and depletion of producing oil and natural gas properties is recorded at the field level, based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs (including wells and related equipment and facilities) are amortized on the basis of proved developed reserves. It has been our historical practice to use our year-end reserve report to adjust our depreciation, depletion, and amortization expense for the fourth quarter. Depreciation, depletion, and amortization expense is calculated using year-end reserve reports based on the SEC-required price. As more fully described in Note 15, proved reserves estimates are subject to future revisions when additional information becomes available.

Asset Retirement Obligation

As described in Note 11, estimated asset retirement costs are recognized when the asset is acquired or placed in service, and are amortized over proved developed reserves using the units-of-production method. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

Unsuccessful Wells

Geological, geophysical and dry hole costs on oil and natural gas properties relating to unsuccessful exploratory wells are charged to expense as incurred.

Impairment

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. The cash flow estimates are based upon third party reserve reports using future expected oil and natural gas prices adjusted for basis differentials. Cash flow estimates for the impairment testing exclude derivative instruments. Refer to Note 7 for additional information.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that we expect to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period. The valuation allowances are reviewed at least annually.

Property acquisition costs are capitalized when incurred.

Support Equipment and Facilities

Support equipment and facilities consist of certain of our water treatment facilities, gathering lines, roads, pipelines and other various support equipment. Items are capitalized when acquired and depreciated using the straight-line method over the useful life of the assets.

Materials and Supplies

Materials and supplies consist of well equipment, parts and supplies. They are valued at the lower of cost or market, using either the specific identification or first-in first-out method, depending on the inventory type. Materials and supplies are capitalized as used in the development or support of our oil and natural gas properties.

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Oil and Natural Gas Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Proved reserves are calculated based on various factors, including consideration of an independent reserve engineers report on proved reserves and an economic evaluation of all of our properties on a well-by-well basis. The process used to complete the estimates of proved reserves at December 31, 2013 and 2012 is described in detail in Note 15.

Reserves and their relation to estimated future net cash flows impact depletion and impairment calculations. As a result, adjustments to depletion and impairments are made concurrently with changes to reserve estimates. The accuracy of reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Derivatives and Hedging Activities

We use derivative financial instruments to achieve a more predictable cash flow from our oil and natural gas production by reducing our exposure to price fluctuations. Additionally, we use derivative financial instruments in the form of interest rate swaps to mitigate interest rate exposure on our borrowings under our reserve-based credit facility.

We account for all our open derivatives as mark-to-market activities. All derivative instruments are recorded in the consolidated balance sheet as either an asset or a liability measured at fair value with changes in fair value recognized in earnings. All of our open derivatives are effective as economic hedges of our commodity price or interest rate exposure. These contracts are accounted for using the mark-to-market accounting method. Using this method, the contracts are carried at their fair value on our consolidated balance sheets under the captions Risk management assets and Risk management liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statements of operations and comprehensive income (loss) under the caption Oil and liquid sales or Natural gas sales and settled interest rate swaps as Interest expense.

Revenue Recognition

Sales of oil and natural gas are recognized when oil or natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale are reasonably assured and the sales price is fixed or determinable. Oil and natural gas is sold on a monthly basis. Most of our sales contracts pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil or natural gas, and prevailing supply and demand conditions, so that the price of the oil or natural gas fluctuates to remain competitive with other available energy supplies. As a result, revenues from the sale of oil and natural gas will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our oil and natural gas contracts are customary in the industry.

Gas imbalances occur when sales are more or less than the entitled ownership percentage of total gas production. We use the entitlements method when accounting for gas imbalances. Any amount received in excess is treated as a liability. If less than the entitled share of the production is received, the excess is recorded as a receivable. There were no gas imbalance positions at December 31, 2013 or 2012, respectively.

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Income Taxes

CEP and each of its wholly-owned subsidiary LLCs are treated as a partnership for federal and state income tax purposes. All of our taxable income or loss, which may differ considerably from net income or loss reported for financial reporting purposes, is passed through to the federal income tax returns of its members. As such, no federal income tax for these entities has been provided for in the accompanying financial statements. CEP is subject to franchise tax obligations in Kansas and Texas and state tax obligations in Alabama and Oklahoma. CEP also has informational filing requirements in Georgia, Indiana, Louisiana, Maine, Missouri, New Jersey, New York, Oregon, Pennsylvania, and West Virginia because we have resident unitholders in these states.

Our wholly-owned subsidiary, CEP Services Company, Inc. is a taxable entity. For the years ended December 31, 2013, and 2012, the current federal and state tax liability for the entity was less than $0.1 million and $0.1 million, respectively. The entity has no deferred tax assets or liabilities. Taxes are paid to the IRS or the applicable states in quarterly installments.

Earnings per Unit

Basic earnings per unit (EPU) is computed by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. To determine net income (loss) allocated to each class of ownership (Class A and Class B), we first allocate net income (loss) in accordance with the amount of distributions made for the period by each class, if any. The remaining net income (loss) is allocated to each class in proportion to the class weighted average number of units outstanding for the period, as compared to the weighted average number of units for all classes for the period.

As of December 31, 2013 and 2012, we had unvested restricted common units outstanding, which were considered dilutive securities. These units will be considered in the diluted weighted average common units outstanding number in periods of net income. In periods of net losses, these units are excluded for the diluted weighted average common unit outstanding number as they are not participating securities.

The following table presents our calculation of basic and diluted units outstanding for the periods indicated:

	Year Ended December 31,	
	2013	**2012**
Weighted average units outstanding during period:		
Class A units Basic and Diluted	933,613	483,564
Class B Common units Basic and Diluted	25,210,106	23,687,946
	26,143,719	24,171,510

At December 31, 2013, we had 380,327 Class B common units that were restricted unvested common units granted and outstanding. These units were excluded from the diluted weighted average common unit outstanding number.

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The following table presents our basic and diluted income per unit for the year ended December 31, 2013 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Loss from continuing operations	$ (25,857)		
Distributions		$	$
Assumed allocation of loss from continuing operations	(25,857)	(517)	(25,340)
Discontinued operations	(2,686)	(54)	(2,632)
Assumed net loss to be allocated	$ (28,543)	$ (571)	$ (27,972)
Basic and diluted loss from continuing operations per unit		$ (0.55)	$ (1.01)
Basic and diluted loss from discontinued operations per unit		$ (0.06)	$ (0.10)
Basic and diluted loss per unit		$ (0.61)	$ (1.11)

The following table presents our basic and diluted income per unit for the year ended December 31, 2012 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Loss from continuing operations	$ (9,462)		
Distributions		$	$
Assumed allocation of loss from continuing operations	(9,462)	(189)	(9,273)
Discontinued operations	(77,081)	(1,542)	(75,539)
Assumed net loss to be allocated	$ (86,543)	$ (1,731)	$ (84,812)
Basic and diluted loss from continuing operations per unit		$ (0.39)	$ (0.39)
Basic and diluted loss from discontinued operations per unit		$ (3.19)	$ (3.19)
Basic and diluted loss per unit		$ (3.58)	$ (3.58)

Comprehensive Loss

Comprehensive loss includes net earnings (loss) as well as unrealized gains and losses on derivative instruments that were previously accounted for as cash flow hedges.

Environmental Cost

We record environmental liabilities at their undiscounted amounts on our balance sheets in other current and long-term liabilities when our environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies clean-up experience and data released by the Federal Environmental Protection Agency (EPA) or other organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and we recognize a current period charge in operation and maintenance expense when clean-up efforts do not benefit future periods.

Unit-Based Compensation

We record compensation expense for all equity grants issued under the Long-Term Incentive Program and the 2009 Omnibus Incentive Compensation Plan based on the fair value at the grant date, recognized over the vesting period.

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Other Contingencies

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against the associated reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

Recent Pronouncements and Accounting Changes

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board (the FASB), which are adopted by us as of the specified effective date. Unless otherwise discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on our consolidated financial statements upon adoption.

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 in accordance with either ASC 210-20-45 or ASC 815-10-45. In January 2013, the FASB issued ASU 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*, an amendment to ASC Topic 210. The update clarifies that the scope of ASU No. 2011-11, *Disclosures about Offsetting Assets and Liabilities*, applies to derivatives accounted for in accordance with ASC Topic 815, *Derivatives and Hedging*, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. The guidance was effective beginning on or after January 1, 2013, and primarily impacts the disclosures associated with our commodity and interest rate derivatives. The adoption of this guidance did not 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 is eliminated. The amended guidance did not have any material impact on our financial statements or our disclosures.

2. DISCONTINUED OPERATIONS

Sale of Robinson s Bend Field Assets

On February 28, 2013, we sold all of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama for $63.0 million, subject to closing adjustments that amounted to approximately $4.0 million. We recorded a loss on the sale of approximately $3.1 million in the three months ended March 31, 2013. The sale of the Robinson s Bend Field assets was initiated to provide the financial flexibility necessary to support our efforts for pursuing opportunities and further developing our properties in the Mid-Continent region, as well as reducing our outstanding debt.

The following amounts relating to the Robinson s Bend Field assets have been reported as discontinued operations in the consolidated statements of operations in the years ending December 31, 2013 and 2012 (in thousands):

	Year Ending December 31, 2013	2012
Revenues	$ 2,304	$ 12,808
Loss from discontinued operations	$ (2,686)	$ (77,081)

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The loss from discontinued operations for the year ended December 31, 2012 included an impairment charge of approximately $73.3 million to impair the asset group that contained our natural gas properties and inventory in the Robinson s Bend Field. This impairment was recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by the cash offer to purchase the assets for $63.0 million, subject to certain post-closing adjustments.

See Note 1 for information regarding earnings per unit, including earnings per unit data relating to income from discontinued operations, which includes loss on sale of discontinued operations in 2013.

The following table provides the major classes of assets and liabilities components of discontinued operations as of December 31, 2013 and 2012 (in thousands):

	December 31, 2013	December 31, 2012
Accounts receivable	$	$ 1,763
Natural gas properties, net	$	$ 67,301
Total discontinued assets	$	$ 69,259
Accounts payable	$	$ 711
Accrued liabilities	$	$ 771
Asset retirement obligation	$	$ 7,692
Total discontinued liabilities	$	$ 9,270

The consolidated statements of cash flows reflect discontinued operations for the years ended December 31, 2013 and 2012.

3. ACQUISITION

Acquisition of Oil, Natural Gas and Natural Gas Liquids Properties from SEP I

On August 9, 2013, we acquired oil, natural gas and natural gas liquids assets in Texas and Louisiana from SEP I for a purchase price of $30.4 million. In conjunction with the acquisitions, SEP I received $20.1 million in cash; 1,130,512 Class A units, which represents 70% of the total Class A units, and 4,724,407 Class B units, which represents 16.6% of the total Class B units. The cash portion of the transaction was financed with cash on hand and a borrowing of $16.7 million under our reserve-based credit facility.

The acquired assets include 67 producing wells in Texas and Louisiana. The primary factors considered by management in acquiring the SEP I properties include the belief that these wells provide an opportunity to significantly increase our reserves, production volumes and drilling portfolio, while maintaining our focus of increasing our oil-weighted assets. The SEP I properties also provide us with access to exploitation and development potential.

The following allocation of the purchase price is preliminary and includes estimates. This preliminary allocation is based on information that was available to management at the time these consolidated financial statements were prepared and takes into account current market conditions and estimated market prices for oil and natural gas. Management has not yet had the opportunity to complete its assessment of fair values of the assets acquired. In addition, the purchase price could change materially as management finalizes adjustments to the purchase price provided for by the purchase and sale agreement, specifically ad valorem taxes, property taxes, franchise taxes and any other state or local taxes . Accordingly, the allocation may change materially as additional information becomes available and is assessed by management.

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The following table summarizes the estimated values of assets acquired and liabilities assumed effective August 1, 2013 (in thousands):

Oil and natural gas properties, equipment and facilities	$ 31,497
Asset retirement obligation	(1,088)
Net assets acquired	$ 30,409

We will finalize the purchase price allocation within one year of the acquisition date.

We have accounted for our acquisition of oil and natural gas properties using the purchase method of accounting for business combinations, and therefore we have estimated the fair value of the assets acquired and the liabilities assumed as of the acquisition date. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves, (ii) future operating and development costs; (iii) future commodity prices, (iv) estimated future cash flows and (v) a market-based weighted cost of capital rate. These inputs require significant judgments and estimates by the Company s management at the time of the valuation and are the most sensitive and subject to change.

Results of Operations and Pro Forma Information

The following table sets forth revenues and lease operating expenses attributable to the SEP I properties acquired (in thousands):

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	**2012**	**2013**	**2012**
Revenue	$ 3,018	$ 5,036	$ 15,782	$ 20,939
Lease Operating Expenses	$ 819	$ 997	$ 3,047	$ 4,049

We have determined that the presentation of net income attributable to the SEP I properties is impracticable due to the integration of the related operations upon acquisition.

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The following supplemental pro forma information presents consolidated results of operations as if the acquisition of the SEP I properties had occurred on January 1, 2012. The supplemental unaudited pro forma information was derived from a) our historical consolidated statements of operations and b) the statements of operations of SEP I. This information does not purport to be indicative of results of operations that would have occurred had the acquisition occurred on January 1, 2012, nor is such information indicative of any expected future results of operations.

	Pro Forma Three Months Ended December 31,		Pro Forma Twelve Months Ended December 31,	
(In thousands)	2013	2012	2013	2012
Revenue	$ 11,458	$ 18,473	$ 56,841	$ 67,466
Income (loss) from continuing operations	$ (13,066)	$ 1,093	$ (18,514)	$ 3,825
Discontinued operations	$	$ (74,055)	$ (2,686)	$ (77,081)
Net Loss	$ (13,066)	$ (72,962)	$ (21,200)	$ (73,256)
Income (loss) from continuing operations per unit				
Class A units Basic and diluted	$ (0.16)	$ 0.01	$ (0.23)	$ 0.05
Class B units Basic and diluted	$ (0.46)	$ 0.04	$ (0.65)	$ 0.13
Discontinued operations per unit				
Class A units Basic and diluted	$	$ (0.92)	$ (0.03)	$ (0.96)
Class B units Basic and diluted	$	$ (2.55)	$ (0.09)	$ (2.66)
Net loss per unit				
Class A units Basic and diluted	$ (0.16)	$ (0.90)	$ (0.26)	$ (0.91)
Class B units Basic and diluted	$ (0.45)	$ (2.52)	$ (0.74)	$ (2.53)
Weighted average units outstanding				
Class A units Basic and diluted	1,615,017	1,613,924	1,615,103	1,614,076
Class B units Basic and diluted	28,457,577	28,412,032	28,057,592	28,412,353

4. FAIR VALUE MEASUREMENTS

We measure certain financial assets and liabilities at fair value. Fair value is defined as an exit price which represents the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in valuing an asset or liability. The accounting guidance also requires the use of valuation techniques to measure fair value that maximize the use of observable inputs and minimize the use of unobservable inputs. As a basis for considering such assumptions and inputs, a fair value hierarchy has been established which identifies and prioritizes three levels of inputs to be used in measuring fair value.

The three levels of the fair value hierarchy are as follows:

Level 1 Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 Inputs other than the quoted prices in active markets that are observable either directly or indirectly, including: quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar assets and liabilities in markets that are not active or other inputs that are observable or can be corroborated by observable market data.

Level 3 Unobservable inputs that are supported by little or no market data and require the reporting entity to develop its own assumptions.

As required by accounting guidance for fair value measurements, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment

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of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 (in thousands):

	Fair Value Measurements at December 31, 2013				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at December 31, 2013
Risk Mgmt Assets	$	$ 11,577	$	$ (975)	$ 10,602
Risk Mgmt Liabilities		(975)		975	
Total Net Assets and Liabilities	$	$ 10,602	$	$	$ 10,602

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 (in thousands):

	Fair Value Measurements at December 31, 2012				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at December 31, 2012
Risk Mgmt Assets	$	$ 31,030	$	$ (5,634)	$ 25,396
Risk Mgmt Liabilities		(6,794)		5,634	(1,160)
Total Net Assets and Liabilities	$	$ 24,236	$	$	$ 24,236

As of December 31, 2013, the estimated fair value of cash and cash equivalents, accounts receivable, other current assets and current liabilities approximated their carrying value due to their short-term nature.

Fair Value of Financial Instruments

Fair value guidance requires certain fair value disclosures, such as those on our debt and derivatives, to be presented in both interim and annual reports. The estimated fair value amounts of financial instruments have been determined using available market information and valuation methodologies described below.

Reserve-Based Credit Facility We believe that 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. The debt is classified as a Level 2 input 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 further in Note 6.

Derivative Instruments 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 inputs. 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.

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5. DERIVATIVE AND FINANCIAL INSTRUMENTS

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. These transactions are normally price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never our intention to enter into derivative contracts for speculative trading purposes.

Under ASC Topic 815, *Derivatives and Hedging*, all derivative instruments are recorded on the consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We will net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives fair values are recognized currently in earnings unless specific hedge accounting criteria are met. We have elected to designate only a portion of our current derivative contracts as hedges; however, changes in the fair value of all of our derivative instruments are recognized in earnings and included as realized and unrealized gains (losses) on derivative instruments in the consolidated statements of operations.

As of December 31, 2013, we had the following derivative contracts in place for the periods indicated, all of which 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,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2014	1,575,000	$ 5.75	1,592,500	$ 5.75	1,610,000	$ 5.75	1,610,000	$ 5.75	6,387,500	$ 5.75
2015	1,215,420	$ 4.25	1,153,487	$ 4.25	1,096,023	$ 4.26	1,050,219	$ 4.26	4,515,149	$ 4.26
2016	1,010,633	$ 4.21	967,290	$ 4.21	923,541	$ 4.21	893,568	$ 4.22	3,795,032	$ 4.21
									14,697,681	

MTM Fixed Price Basis Swaps Enable Gas Transmission, LLC (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,		September 30,		December 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
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
									4,443,677	

MTM Fixed Price Basis Swaps West Texas Intermediate (WTI)

	For the quarter ended (in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2014	60,928	$ 94.64	57,154	$ 94.67	53,797	$ 94.72	50,597	$ 94.80	222,476	$ 94.70
2015	47,747	$ 90.95	45,065	$ 91.00	42,672	$ 91.04	40,329	$ 91.10	175,813	$ 91.02
2016	17,957	$ 85.50	16,985	$ 85.50	16,048	$ 85.50	15,127	$ 85.50	66,117	$ 85.50
									464,406	

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The table below outlines the classification of our derivative financial instruments on the consolidated balance sheets (in thousands):

Derivative Type	Location of Asset/(Liability) On Balance Sheet	Fair Value of Asset/(Liability) On Balance Sheet December 31, 2013	December 31, 2012
Commodity MTM	Risk management assets current	$ 10,043	$ 19,005
Commodity MTM	Risk management assets non-current	1,534	12,025
	Total gross assets	11,577	31,030
Commodity MTM	Risk management assets current	(903)	(1,040)
Commodity MTM	Risk management assets non-current	(72)	(946)
Commodity MTM	Risk management liabilities current		(523)
Commodity MTM	Risk management liabilities non-current		(637)
Interest Rate MTM	Risk management assets non-current		(3,648)
	Total gross liabilities	(975)	(6,794)
	Total net assets and liabilities	$ 10,602	$ 24,236

The effect of derivative instruments on our consolidated statements of operations was as follows (in thousands):

Derivative Type	Location of Gain/(Loss) in Income	Amount of Gain/(Loss) in Income For the Year Ended December 31, 2013	2012
Commodity MTM	Oil and natural gas sales	$ (1,486)	$ 15,701
Interest Rate MTM	Interest expense	(65)	(1,061)
	Total	$ (1,551)	$ 14,640

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 For the Three Months Ended December 31, 2013	2012
Commodity Cash Flow	Natural gas sales	$	$ 1,271
	Total	$	$ 1,271

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with two counterparties. We generally execute commodity derivative instruments under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election.

We monitor the creditworthiness of our counterparties; however, we are not able to predict sudden changes in counterparties creditworthiness. In addition, if such changes are sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of our counterparties not perform, we may not realize the benefit of some of our derivative instruments with lower commodity prices and my incur losses. We include a measure of counterparty credit risk in our estimates of the fair values of the derivative instruments in an asset position.

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 our 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 December 31, 2013 and 2012, respectively, the impact of non-performance credit risk on the valuation of our net assets from counterparties was not significant

Under the terms of our reserve-based credit facility, we have agreed to hedge 100% of our reasonably estimated projected natural gas production for 2015 and 2016 . All of the required hedges were executed prior to December 31, 2013.

Hedge Liquidation, Repositioning and Novation

In connection with the sale of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama, we liquidated 395,218 MMbtu of NYMEX swaps in 2013 and 1,634,530 MMbtu of NYMEX swaps in 2014 at a cost of $0.3 million. In addition, we reduced our outstanding NYMEX swap positions in 2013 by 1,041,814 MMbtu by executing offsetting trades with one of our counterparties at a fixed price of $3.66 per Mcf . These transactions ensure that our outstanding derivative positions in future periods are lower than our expected future natural gas production in those periods. We also amended a 2014 to 2015 oil trade with one of our hedge counterparties to lower the stated swap price from $98.10 to $93.50 per barrel, on a total of 58,157 barrels of oil. We received proceeds of approximately $0.2 million upon execution of the amendment. The proceeds were used for working capital purposes.

In March 2013, we reduced our outstanding interest rate swaps that fixed our LIBOR rate through 2014 to $30 million, which resulted in additional interest rate swap settlements of $2.1 million. This position was terminated in May 2013 resulting in an offsetting non-cash gain in our mark-to-market interest swap activities.

In May 2013, in conjunction with amendments to our reserve-based credit facility and the exit of certain lenders from our bank syndicate, we novated certain of our commodity hedges to Societe General, which increased our natural gas settlement cost by $0.3 million.

6. DEBT

Reserve-Based Credit Facility

In May 2013, we refinanced our $350.0 million reserve-based credit facility with Societe Generale as administrative and collateral agent and a syndicate of lenders, extending its maturity to May 30, 2017 and increasing our borrowing base from $37.5 million to $55.0 million. Borrowings under the reserve-based credit facility are secured by various mortgages of oil and natural gas properties that we and certain of our subsidiaries own, as well as various security and pledge agreements among us and certain of our subsidiaries and the administrative agent. The 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 December 31, 2013, we had borrowed $50.7 million under our reserve-based credit facility and our borrowing base was $55.0 million. At December 31, 2013, the lenders and their percentage commitments in the reserve-based credit facility were Societe Generale (36.36%), OneWest Bank, FSB (36.36%) and BOKF NA, dba Bank of Oklahoma (27.28%).

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 December 31, 2013, no letters of credit were outstanding.

At our election, interest for borrowings is 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

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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. The reserve-based credit facility limits our ability to pay distributions to unitholders and permits us to hedge our projected monthly production, as discussed below, and the interest rate on our borrowings.

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 Accounting Standards Codification (ASC) Topic 815, *Derivatives and Hedging;* ASC Topic 410, *Asset Retirement and Environmental Obligations* and ASC Topic 360, *Property, Plant and Equipment*. All financial covenants are calculated using our consolidated financial information and are discussed below.

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. These events have not both occurred, so a change in control had not occurred as of December 31, 2013. 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 our 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 December 31, 2013, 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, Exelon s or SOG s ownership in us.

Compliance with Financial Covenants

At December 31, 2013, 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 December 31, 2013, our actual Total Net Debt to annual Adjusted EBITDA ratio was 2.6 to 1.0, compared to a required ratio of not greater than 3.5 to 1.0; our actual ratio of consolidated current assets to consolidated current liabilities was 1.3 to 1.0, compared to a required ratio of not less than 1.0 to 1.0 and our actual quarterly Adjusted EBITDA to cash interest expense ratio was 9.3 to 1.0, compared to a required ratio of not less than 2.5 to 1.0.

If we are unable to remain in compliance with the financial covenants contained in our reserve-based credit facility or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of our reserve-based credit facility, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

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 December 31, 2013, our borrowing base was $55.0 million. The borrowing base is re-determined semi-annually, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports 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.

Funds Available for Borrowing

As of December 31, 2013, we had $50.7 million in outstanding debt under our reserve-based credit facility and $4.3 million in remaining borrowing capacity. At December 31, 2012, we had $84 million in outstanding debt under our reserve-based credit facility.

Debt Issue Costs

As of December 31, 2013, our unamortized debt issue costs were approximately $0.8 million. These costs are being amortized over the life of the credit facility. At December 31, 2012, our unamortized debt issue costs were approximately $1.2 million.

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7. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties consist of the following (in thousands):

	December 31,	
	2013	2012
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 636,816	$ 591,889
Unproved property	1,589	1,380
Total property costs	638,405	593,269
Materials and supplies	1,054	771
Land	751	751
Total	640,210	594,791
Less: Accumulated depreciation, depletion, amortization and impairments	(495,215)	(474,669)
Oil and natural gas properties and equipment, net	$ 144,995	$ 120,122

Depreciation, depletion, amortization and impairments consisted of the following (in thousands):

	Year Ended December 31,	
	2013	2012
DD&A of oil and natural gas-related assets	$ 18,972	$ 11,732
Asset Impairments	2,357	109
Total	$ 21,329	$ 11,841

Impairment Charges

Our non-cash asset impairment charges for the year ended December 31, 2013 were $2.3 million, compared to $0.1 million for the same period in 2012. Our non-cash impairment charges in 2013 were approximately $2.1 million to impair the value of our oil and natural gas fields in Texas and Louisiana and $0.2 million to impair certain of our wells in the Woodford Shale.

Our non-cash impairment charges in 2012 were approximately $0.1 million to impair certain properties in the Woodford Shale. The 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.

Asset Sales

In 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 seven years, buildings are depreciated over a life of 20 years and pipeline and gathering systems are depreciated over a life of 25 to 40 years.

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Exploration and Dry Hole Costs

We recorded no exploration and dry hole costs for the years ended December 31, 2013 and 2012. 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.

8 . BENEFIT PLANS

Eligible employees of CEP participate in an employment savings plan. Matching contributions made by us were approximately $0.3 million and $0.5 million years ended December 31, 2013 and 2012, respectively.

9. RELATED PARTY TRANSACTIONS

Unit Ownership

PostRock, Exelon and SOG, through subsidiaries, own a portion of our outstanding units. As of December 31, 2013, CEPM, a subsidiary of PostRock, owned 484,505, or 30%, of our Class A units and 5,918,894 of our Class B common units. CEPH, a subsidiary of Exelon, owned all of our Class C management incentive interests and all of our Class D interests as of December 31, 2013. SEP I, a subsidiary of SOG, owned 1,130,512, or 70%, of our Class A units and 4,724,407 of our Class B common units.

PostRock-Related Announcements

In 2011, PostRock acquired certain of our Class A units and Class B common units in two separate transactions which represented a 21.3% ownership interest in us at December 31, 2013. Approval of the purchase of these units was neither required nor given by our board of managers or conflicts committee. We believe PostRock is now an interested unitholder under Section 203 of the Delaware General Corporation Law, which is applicable to us pursuant to our operating agreement. Section 203, as it applies to us, prohibits an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in business combinations with us for three years following the time such person becomes an interested unitholder without the approval of our board of managers and the vote of 66 2/3% of our outstanding Class B common units, excluding those held by the interested unitholder. Section 203 broadly defines business combination to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. In addition to limiting our ability to enter into transactions with PostRock or its affiliates, this provision of our operating agreement could have an anti-takeover effect with respect to transactions not approved in advance by our board of managers, including discouraging takeover attempts that might result in a premium over the market price for our common units. We believe the Section 203 restrictions related to these unit purchases expire in December 2014.

Sanchez-Related Announcements

In August 2013, SOG acquired certain of our Class A units and Class B common units and one Class Z unit in one transaction which represented a 19.5% ownership interest in us at December 31, 2013. These units were issued to SOG, along with cash, in exchange for oil and natural gas properties located in Texas and Louisiana.

In August 2013, the Company also entered into a Registration Rights Agreement with SOG pursuant to which the Company granted to SOG certain registration rights related to the unit consideration thereunder. Under the Registration Rights Agreement, the Company granted SOG demand registration rights with respect to the preparation and filing with the SEC of one or more registration statements for the purpose of registering the resale of the securities that will be registered.

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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 operating 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 or share in distributions upon liquidation.

Class D Interest

The majority of our properties in the Robinson s Bend Field were subject to a non-operated net profits interest (NPI) held by Torch Energy Royalty Trust (the Trust). Through the NPI, the Trust was entitled to a royalty payment, calculated as a percentage of the net revenue from specified wells in the Robinson s Bend Field (the Trust Wells).

Under the terms of the NPI and related contractual arrangements, the royalty payment we were required to make to the Trust under the NPI was calculated using a sharing arrangement with a pricing formula that had resulted in below-market prices and had the effect of keeping our payments to the Trust significantly lower than if such payments had been calculated on then prevailing market prices.

In order to address the risks of early termination, without the prior consent of our board of managers, of the sharing arrangement in respect of the calculation of amounts payable to the Trust for the NPI and the potential reduction in our revenues resulting therefrom, Constellation Holdings, Inc. (CHI) contributed $8.0 million to us for all of our Class D interests. This contribution was potentially to be distributed to CHI in 24 distributions over a period of approximately six years if the sharing arrangement remained in effect during that period. If the amounts payable by us to the Trust were not calculated based on the continued applicability of the sharing arrangement through December 31, 2012, unless such change was approved in advance by our board of managers and our conflicts committee, the following would occur: the Class D interests would cease receiving the cash distributions; and the Class D interest would only be returned the remaining undistributed amount of the $8.0 million contribution under certain circumstances upon our liquidation.

No payments for the NPI were ever made to the Trust. On January 8, 2009, we were served by Trust Venture, on behalf of the Trust, with a purported derivative action filed in the Circuit Court of Tuscaloosa County, Alabama (the Circuit Court). The lawsuit alleged, among other things, a breach of contract under the conveyance associated with the NPI and the agreement establishing the Trust and asserted that above market rates for services were paid, reducing the amounts paid to the Trust in connection with the NPI. The lawsuit sought unspecified damages and an accounting of the NPI. The lawsuit was settled in June 2011. The settlement with Trust Venture, its successor and the Trust provided, among other things, that we pay $1.2 million to reimburse Trust Venture and its successor for their legal fees and expenses incurred in prosecuting the lawsuit and that we acquire the NPI from the Trust for $1.0 million. When the NPI was assigned to us by the Trust in the fourth quarter of 2011, the NPI was extinguished. We recognized a $1.0 million charge to impair the value of the extinguished NPI contract that was acquired. The finalization of this settlement impacted our Class D interests. The NPI no longer burdened our properties in the Robinson s Bend Field upon their sale in February 2013.

CEPH, a subsidiary of Exelon and the successor to CHI, holds all of our Class D interests. Due to their contingently redeemable feature, the Class D interests were treated as temporary equity. Since the NPI is no longer being paid based upon the sharing arrangement and we have suspended distributions since June 2009, there should be no further distributions required on the Class D interests. Accordingly, the Class D interests were moved from temporary equity to permanent equity (Class A and Class B) in the fourth quarter of 2011. The Class D interests will remain outstanding until the liquidation of CEP and could receive up to $6.7 million under certain circumstances at that time.

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Class Z Unit

SOG holds the one Class Z unit of CEP. This one unit is a non-voting unit, except voting as a separate class must approve the issuance of additional Company securities, other than Class B common units, prior to the issuance of such securities. The Class Z unit is a non-economic interest, without any right to participate in distributions or allocations.

10. COMMITMENTS AND CONTINGENCIES

On August 30, 2013, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPM, Gary M. Pittman and John R. Collins against the Company, certain of its officers and managers, SOG and SEP I in connection with the Company s closing on August 9, 2013 of the purchase of oil and natural gas properties from SEP I and the issuance of units in connection therewith. The plaintiffs contend, among other things, that the issuance of the units to SEP I in connection with the acquisition was not permitted under the Company s operating agreement, that Messrs. Pittman and Collins should not have been removed as the Class A managers of the Company s board of managers, and that SEP I, SOG and our current Class A managers participated in the bad faith conduct of the other defendants and interfered with CEPM s contractual rights under the Company s operating agreement. The plaintiffs allege claims against the Company and certain of its managers and officers relating to breach of contract, breach of the duty of good faith, and breach of the implied covenant of good faith and fair dealing; the plaintiffs also allege aiding and abetting and tortuous interference claims against SOG, SEP I and our current Class A managers. The plaintiffs seek, among other things, declaratory relief reappointing Messrs. Pittman and Collins to the Company s board of managers and removing our current Class A managers therefrom, and an injunction against the Company taking any further action outside the ordinary course of business during the pendency of the litigation, declaratory relief rescinding the units issued by the Company to SEP I, declaratory relief that CEPM has sole voting power with respect to the outstanding Class A units, declaratory relief that the Company officers and managers have breached fiduciary and contractual duties and are not entitled to indemnification from the Company as a result thereof, and monetary damages. The parties to the lawsuit are currently working on the terms of a settlement agreement. In anticipation of a settlement being reached, we have accrued a probable liability of $5.9 million.

11. 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 oil and natural gas wells, and decommissioning of oil and natural gas gathering and other 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.

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The following table is a reconciliation of the ARO (in thousands):

	December 31, 2013	December 31, 2012
Asset retirement obligation, beginning balance	$ 7,665	$ 7,052
Liabilities added from acquisitions	1,088	
Liabilities added from drilling	244	162
Settlements	(3)	(8)
Accretion expense	519	459
Asset retirement obligation, ending balance	$ 9,513	$ 7,665

Additional retirement obligations increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Actual expenditures for abandonments of oil and natural gas wells and other facilities reduce the liability for asset retirement obligation. In 2013 and 2012, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing asset retirement obligations.

12 . UNIT-BASED COMPENSATION

We have the following unit-based compensation plans:

We have the 2009 Omnibus Incentive Compensation Plan (Omnibus Plan), which is a plan under which restricted common unit awards are granted to certain employees in Texas. The Omnibus Plan provides for a variety of unit-based and performance-based awards, including unit options, restricted units, unit grants, notional units, unit appreciation rights, performance awards and other unit-based awards. Awards under the Omnibus Plan may be paid in cash, units or any combinations thereof as determined by the compensation committee of our board of managers.

Restricted unit activity (number of units) under the Omnibus Plan was as follows:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2011	962,281	$ 3.41
Vested	(215,308)	3.40
Granted	7,190	1.32
Returned/Cancelled	(87,385)	3.40
Outstanding at December 31, 2012	666,778	3.39
Vested	(370,363)	2.66
Granted	184,313	1.27

Returned/Cancelled	(144,177)		2.77
Outstanding at December 31, 2013	336,551	$	3.29

We have the Long-Term Incentive Program (L-TIP), which is a plan under which restricted common unit awards are granted to certain field employees in Alabama, Kansas and Oklahoma and to certain employees in Texas.

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Restricted unit activity (number of units) under the L-TIP Plan was as follows:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2011	149,869	$ 3.44
Vested	(56,025)	3.42
Granted	30,000	2.17
Returned/Cancelled	(28,930)	3.42
Outstanding at December 31, 2012	94,914	3.05
Vested	(61,273)	2.24
Granted	38,023	1.17
Returned/Cancelled	(27,888)	2.56
Outstanding at December 31, 2013	43,776	$ 2.87

We recognized approximately $1.0 million and $1.5 million of non-cash compensation expense related to our unit-based compensation plans in the twelve months ended December 31, 2013 and 2012, respectively. As of December 31, 2013, we had approximately $0.5 million in unrecognized compensation expense related to our unit-based compensation plans expected to be recognized through the first quarter of 2015.

13. DISTRIBUTIONS TO UNITHOLDERS

Beginning in June 2009, we suspended our quarterly distributions to unitholders. For twelve months ended December 31, 2013 and 2012, respectively, 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.

14. MEMBERS EQUITY

2013 Equity

At December 31, 2013, we had 1,615,017 Class A units and 28,462,185 Class B common units outstanding, which included 43,776 unvested restricted common units issued under our Long-Term Incentive Plan and 336,551 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan.

At December 31, 2013, we had granted 346,734 common units of the 450,000 common units available under our Long-Term Incentive Plan. Of these grants, 302,958 have vested.

At December 31, 2013, we had granted 1,366,666 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 1,030,115 have vested.

For the year ended December 31, 2013, 139,810 common units were 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.

2012 Equity

At December 31, 2012, we had 483,418 Class A units and 23,687,507 Class B common units outstanding, which included 94,914 unvested restricted common units issued under our Long-Term Incentive Plan and 666,778 unvested restricted common units issued under our 2009 Omnibus Incentive Compensation Plan.

At December 31, 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. Of these grants, 38,023 have vested.

At December 31, 2012, we had granted 1,326,530 common units of the 1,650,000 common units available under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 659,752 have vested. We also granted an additional 323,194 performance units under our 2009 Omnibus Incentive Compensation Plan. Of these grants, 161,597 have vested.

For the year ended December 31, 2012, 90,425 common units were tendered by our employees for tax withholding purposes. These units, costing approximately $0.2 million, were returned to their respective plan and are available for future grants.

15. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES

(UNAUDITED)

The Supplementary Information on Oil and Natural Gas Producing Activities is presented as required by the appropriate authoritative guidance . The supplemental information includes capitalized costs related to oil and natural gas producing activities; costs incurred for the acquisition of oil and natural gas producing activities, exploration and development activities and the results of operations from oil and natural gas producing activities.

Supplemental information is also provided for per unit production costs; oil and natural gas production and average sales prices; the estimated quantities of proved oil and natural gas reserves; the standardized measure of discounted future net cash flows associated with proved reserves and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved reserves.

In February 2013, we sold all of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama. Information related to these assets is classified as discontinued operations.

Costs

The following table sets forth capitalized costs for the years ended December 31, 2013 and 2012 (in thousands):

	December 31, 2013	December 31, 2012
Capitalized costs at the end of the period:(a)		
Oil and natrual gas properties and related equipment (successful efforts method)		
Property costs		
Proved property	$ 636,816	$ 591,889
Unproved property	1,589	1,380
Total property costs	638,405	593,269
Materials and supplies	1,054	771
Land	751	751
Total	640,210	594,791
Less: Accumulated depreciation, depletion, amortization and impairments	(495,215)	(474,669)
Oil and natural gas properties and equipment, net	$ 144,995	$ 120,122

(a) Capitalized costs include the cost of equipment and facilities for our oil and natural gas producing activities. Proved property costs include capitalized costs for leaseholds holding proved reserves; development wells and related equipment and facilities (including uncompleted development well costs); and support equipment. Unproved property costs include capitalized costs for oil and natural gas leaseholds where proved reserves do not exist.

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The following table sets forth costs incurred for oil and natural gas producing activities for the years ended December 31, 2013 and 2012 (in thousands):

	For the year ended December 31,	
	2013	**2012**
Costs incurred for the period:		
Acquisition of properties		
Proved	$ 20,012	$ 75
Unproved	209	177
Development costs	15,694	15,336
Oil and natural gas properties and equipment, net	$ 35,915	$ 15,588

The development costs for the years ended December 31, 2013 and 2012 primarily represent costs to develop our proved undeveloped reserves. The properties acquired in 2013 were in Texas and Louisiana.

We had no exploration and dry hole costs in 2013 and 2012, respectively.

Results of Operations

The revenues and expenses associated directly with oil and natural gas producing activities are reflected in the Consolidated Statements of Operations and Comprehensive Income (Loss). All of our operations are oil and natural gas producing activities located in the United States.

Net Proved Oil and Natural Gas Reserves

The following table sets forth information with respect to changes in proved developed and undeveloped reserves. This information excludes reserves related to royalty and net profit interests. All of our reserves are located in the United States.

	For the year ended December 31,	
	2013	**2012**
(In Mmcfe)		
Beginning balance	92,982	201,330
Extensions and discoveries	4,825	2,049
Purchases of reserves in place	7,150	
Sales of reserves in place	(49,385)	(256)
Revisions of previous estimates	44,727	(97,178)
Production	(9,045)	(12,963)
Ending balance	91,254	92,982

Ending balance from continuing operations	91,254	43,596
Ending balance from discontinued operations(a)		49,386
Total ending balance	91,254	92,982
Proved developed reserves from continuing operations	78,629	40,867
Proved developed reserves from discontinued operations		49,134
Total proved developed reserves	78,629	90,001
Proved undeveloped reserves from continuing operations	12,625	2,729
Proved undeveloped reserves from discontinued operations		252
Total proved undeveloped reserves	12,625	2,981

(a) In February 2013, we sold all of our Black Warrior Basin properties**.**

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Reserves and Related Estimates

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters.

Our December 31, 2013 and 2012 proved reserve estimates were 91.3 Bcfe and 93.0 Bcfe, respectively. For these years, NSAI, an independent petroleum engineering firm, prepared the estimates of our proved reserves which were used to prepare our financial statements.

Our 2013 estimates of total proved reserves decreased 1.7 Bcfe from 2012 due to the sale of our Black Warrior Basin properties in the amount of 49 Bcfe offset by the acquisition of the Sanchez properties, which added 7 Bcfe. We added 4.8 Bcfe due to extensions and discoveries in the Cherokee Basin reserves added for oil opportunities. Our reserve revisions of 44.8 Bcfe are primarily the result of higher natural gas prices. Our reserves are 85% natural gas and are sensitive to lower prices for natural gas and basis differentials in the Mid-Continent region. For the proved reserves, the production weighted average product price over the remaining lives of the properties used in our reserve report were: $97.89 per barrel for oil, $41.21 per barrel for natural gas liquids and $3.706 per Mcf for natural gas. Any of our locations that are scheduled to be drilled after 5 years are classified as probable or possible reserves to the extent they are economic.

Our 2012 estimates of total proved reserves decreased 108.3 Bcfe from 2011 due to a lower SEC-required price for natural gas used to calculate our reserves in 2012. We added 2.0 Bcfe due to extensions and discoveries in the Cherokee Basin reserves added for oil opportunities and 0.2 Bcfe of natural gas reserves. Our reserve revisions of 97.2 Bcfe are primarily the result of lower natural gas prices causing our reserves to no longer be considered economic under SEC rules. Our reserves are 93% natural gas and are sensitive to lower prices for natural gas and basis differentials in the Mid-Continent region. Although we utilize swaps and basis swaps to mitigate commodity price risk and basis differentials, these derivatives are not used when preparing our reserve report based on SEC rules. The SEC-required price used to prepare our reserve report was $2.91 in the Cherokee Basin and $2.85 in the Black Warrior Basin. The SEC-required prices used in the Cherokee Basin and in the Black Warrior Basin declined from 2011 to 2012 by $0.97 and $1.35, respectively. Our actual 2012 production of 12.6 Bcfe is 3.8 Bcfe higher than what our 2011 reserve report estimated for 2012. A significant number of our wells that actually produced natural gas in 2012 were not included in our 2011 reserve report as they were deemed uneconomic at the SEC-required price which excludes the impact of our swaps and basis swaps used to mitigate commodity price risk and basis differentials. Any of our locations that are scheduled to be drilled after 5 years are classified as probable or possible reserves to the extent they are economic.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas Reserves, Including a Reconciliation of Changes Therein

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved oil and natural gas reserves. Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below.

Future cash inflows are calculated by applying the SEC-required prices of oil and natural gas relating to our proved reserves to the year-end quantities of those reserves. Future cash inflows exclude the impact of our hedging program. Future development and production costs represent the estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. In addition, asset retirement obligations are included within future production and development costs. There are no future income tax expenses because CEP is a non-taxable entity.

The assumptions used to compute estimated future cash inflows do not necessarily reflect expectations of actual revenues or costs or their present values. In addition, variations from expected production rates could

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result directly or indirectly from factors outside of our control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production; however, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

The following table summarizes the standardized measure of estimated discounted future cash flows from the oil and natural gas properties (in thousands):

	For the year ended December 31, 2013	2012
Future cash inflows	$ 502,831	$ 360,825
Future production costs	(227,315)	(194,198)
Future estimated development costs	(40,694)	(11,124)
Future net cash flows	234,822	155,503
10% annual discount for estimated timing of cash flows	(91,108)	(65,834)
Standardized measure of discounted estimated future net cash flows related to proved gas reserves	$ 143,714	$ 89,669
Standardized measure from continuing operations	143,714	60,455
Standardized measure from discontinued operations(a)		29,214
Standardized measure of discounted estimated future net cash flows related to proved gas reserves	$ 143,714	$ 89,669

(a) In February 2013, we sold all of our Black Warrior Basin properties.

The following table summarizes the principal sources of change in the standardized measure of estimated discounted future net cash flows (in thousands):

	For the year ended December 31, 2013	2012
Beginning of the period	$ 89,669	$ 160,691
Sales and transfers of oil and natural gas, net of production costs	(21,244)	(39,699)
Net changes in prices and production costs related to future production	50,425	(19,228)
Development costs incurred during the period	5,615	18,818
Changes in extensions and discoveries	28,494	12,590
Revisions of previous quantity estimates	21,455	(83,750)
Sales of reserves in place	(2,297)	(1,476)
Accretion discount	8,967	16,069

Other	(37,370)	25,654
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 143,714	$ 89,669
Standardized measure from continuing operations	143,714	60,455
Standardized measure from discontinued operations(a)		29,214
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 143,714	$ 89,669

(a) In February 2013, we sold all of our Black Warrior Basin properties.

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16. SUBSEQUENT EVENTS

The following events have occurred subsequent to the date of the balance sheet or prior to the filing of this Annual Report on Form 10-K that could have a material impact on our consolidated financial statements or results of operations:

On February 28, 2014, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPH against the Company (the Exelon Litigation) seeking repayment of suspended distributions in relation to the Class D Interests held by CEPH. In 2006, Constellation Holding, Inc (CHI), which merged with and into CEPH in December 2012, purchased the Company s Class D Interests for $8.0 million. The $8.0 million was to be repaid to CEPH in quarterly distributions of $333,333.33 over a period of six years; however, these distributions could be temporarily suspended if a dispute arose over pricing formulas related to the sale of natural gas from the Robinson s Bend properties. A dispute arose, so the distributions were suspended pursuant to the Company s operating agreement and never reinstated. CEPH contends, among other things, that the Company breached its contract to pay the quarterly distributions, acted in bad faith and received unjust enrichment by suspending the quarterly distributions. The Company believes that the allegations contained in the lawsuit are without merit and intends to vigorously defend itself against the claims raised in the complaint. In conjunction with its defense in the Exelon Litigation, the Company anticipates that it will incur legal and other costs that may have a material effect on available cash which could impact CEP s ability to make distributions.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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: March 27, 2014

By /s/ STEPHEN R. BRUNNER

Stephen R. Brunner

Chief Executive

Officer, Chief Operating

Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Constellation Energy Partners LLC, the Registrant, and in the capacities and on the dates indicated.

	Signature	Title	Date
Principal executive officer:			
By	/s/ STEPHEN R. BRUNNER	Chief Executive Officer, Chief	
	Stephen R. Brunner	Operating Officer and President	March 27, 2014
Principal financial officer and treasurer:			
By	/s/ CHARLES C. WARD	Principal Financial Officer and	
	Charles C. Ward	Principal Accounting Officer	March 27, 2014
Managers:			
	/s/ RICHARD H. BACHMANN **Richard H. Bachmann**	Manager	March 27, 2014
	/s/ RICHARD S. LANGDON **Richard S. Langdon**	Manager	March 27, 2014

/s/ Antonio R. Sanchez **Antonio R. Sanchez**	Manager	March 27, 2014
/s/ John N. Seitz **John N. Seitz**	Manager	March 27, 2014
/s/ Gerald F. Willinger **Gerald F. Willinger**	Manager	March 27, 2014

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Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.2	Purchase and Sale Agreement, dated as of March 8, 2007, between EnergyQuest Resources, L.P., Oklahoma Processing EQR, LLC, Kansas Production EQR, LLC and Kansas Processing EQR, LLC and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
2.3	Agreement of Merger, dated as of July 12, 2007, among AMVEST Osage, Inc., AMVEST Oil & Gas, Inc. and CEP Mid-Continent LLC, f/k/a CEP Cherokee Basin LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).
2.4	Purchase and Sale Agreement, dated as of August 2, 2007, between Newfield Exploration Mid-Continent Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).
2.5	Nominee Agreement, dated as of September 21, 2007, by and between Newfield Exploration Mid-Continent Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007).
2.6	Asset Purchase and Sale Agreement, dated as of May 12, 2005, by and among Everlast Energy LLC, RB Marketing Company LLC, Robinson s Bend Operating Company LLC and CBM Equity IV, LLC (incorporated herein by reference to Exhibit 10.9 to Amendment No. 2 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on September 29, 2006.
2.7	Agreement for Purchase and Sale, dated as of February 19, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.8	First Amendment to Agreement for Purchase and Sale, dated as of March 31, 2008, among CoLa Resources LLC and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 3, 2008, File No. 001-33147).
2.9	Oil and Gas Purchase Contract, dated as of October 1, 1993, by and between Torch Energy Marketing, Inc. and Torch Royalty Company (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2 to the Registration Statement on Form S-1 filed by Constellation Energy Partners LLC on June 29, 2006, File No. 333-134995).
2.1	Membership Interest Purchase and Sale Agreement, dated February 1, 2013 between Constellation Energy Partners LLC and Constellation Commodities Upstream LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report and Form 8-K filed by Constellation Energy Partners LLC on February 4, 2013, File No. 001-33147).

2.11	Contribution Agreement, dated as of August 9, 2013, by and between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K field by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).

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Exhibit Number	Description
3.1	Certificate of Formation of Constellation Energy Partners LLC, as amended (incorporated herein by reference to Exhibit 3.1 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 12, 2007, File No. 001-33147).
3.2	Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
3.3	Amendment No. 1 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of April 23, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 24, 2007, File No. 001-33147).
3.4	Amendment No. 2 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of July 25, 2007. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on July 26, 2007, File No. 001-33147).
3.5	Amendment No. 3 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of September 21, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on September 26, 2007, File No. 001-33147).
3.6	Amendment No. 4 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of December 28, 2007 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on December 28, 2007, File No. 001-33147).
3.7	Amendment No. 5 to Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC, dated as of August 9, 2013 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).
10.1	Second Amended and Restated Credit Agreement dated as of May 30, 2013, among Constellation Energy Partners LLC, as borrower, Societe Generale, as administrative agent, and the lenders party hereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 31, 2013, File No. 001-33147).
10.2	Trademark License Agreement, dated as of November 20, 2006, by and among Constellation Energy Group, Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006, File No. 001-33147).
10.3	Exploration and Development Agreement, dated July 25, 2005, by and between The Osage Nation and AMVEST Osage, Inc. (incorporated herein by reference to Exhibit 10.23 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.4	Substituted and Replaced First Amendment to the Exploration and Development Agreement, dated October 18, 2006, by and between The Osage Nation and AMVEST Osage, Inc.

	(incorporated herein by reference to Exhibit 10.24 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).
10.5	Assignment, Assumption and Ratification Agreement, dated as of July 25, 2007, by and between AMVEST Osage, Inc. and CEP Mid-Continent LLC (incorporated herein by reference to Exhibit 10.25 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 27, 2009, File No. 001-33147).

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Exhibit Number	Description
10.6	Water Gathering and Disposal Agreement, dated as of August 9, 1990, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.17 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.7	First Amendment to Water Gathering and Disposal Agreement, dated as of October 1, 1993, by and between Torch Energy Associates Ltd. and Valasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.18 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.8	Second Amendment to Water Gathering and Disposal Agreement, dated as of November 30, 2004, by and between Robinson s Bend Operating Company, LLC and Everlast Energy LLC (incorporated herein by reference to Exhibit 10.19 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on March 4, 2008, File No. 001-33147).
10.9	Third Amendment, dated June 13, 2011, to Water Gathering and Disposal Agreement dated November 30, 2004, by and between Robinson s Bend Operating II, LLC, Robinson s Bend Production II, LLC and Torch Energy Associates Ltd. (incorporated herein by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on June 15, 2011, File No. 001-33147).
10.1	Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Stephen R. Brunner (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).
10.11	Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Charles C. Ward (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).
10.12	Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Lisa J. Mellencamp (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).
10.13	Amended and Restated Employment Agreement, dated April 5, 2012, by and between CEP Services Company, Inc. and Michael B. Hiney (incorporated herein by reference to Exhibit 10.4 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on April 6, 2012, File No. 001-33147).
10.14	Employment Agreement, dated as of February 15, 2013, between Elizabeth Ann Evans and CEP Services Company, Inc. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on February 19, 2013, File No. 001-33147).
10.15	Constellation Energy Partners LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 20, 2006, File No. 001-33147).
10.16	

	Constellation Energy Partners LLC 2009 Omnibus Incentive Compensation Plan (incorporated herein by reference to Exhibit A to the Proxy Statement filed by Constellation Energy Partners LLC on October 22, 2009, File No. 001-33147).
10.17	Form of Grant Agreement Relating to Notional Units with DERs Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.9 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 4, 2009, File No. 001-33147).

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Exhibit Number	Description
10.18	Form of Grant Agreement Relating to Notional Units with DERs Independent Managers (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.10 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 4, 2009, File No. 001-33147).
10.19	Form of Grant Agreement Relating to Restricted Units Executives (under the 2009 Omnibus Incentive Compensation Plan incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on March 3, 2010, File No. 001-33147).
+10.20	Form of Amended and Restated Grant Agreement Relating to Unit-Based Awards Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on August 5, 2011, File No. 001-33147).
+10.21	Amendment to Amended and Restated Grant Agreement Relating to Unit-Based Awards-Executives (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Constellation Energy Partners LLC on May 10, 2012, File No. 001-33147).
+10.22	Form of Grant Agreement Relating to Restricted Units Independent Managers (under the 2009 Omnibus Incentive Compensation Plan) (incorporated herein by reference to Exhibit 10.30 to the Annual Report on Form 10-K filed by Constellation Energy Partners LLC on February 25, 2010, File No. 001-33147).
+10.23	Registration Rights Agreement, dated as of August 9, 2013, between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).
*21.1	List of subsidiaries of Constellation Energy Partners LLC.
*23.1	Consent of KPMG LLP.
*23.2	Consent of PricewaterhouseCoopers LLP.
*23.3	Consent of Netherland, Sewell & Associates, Inc.
*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.
*99.1	Report of Netherland, Sewell & Associates, Inc.

*101.INS	XRBL Instance Document
*101.SCH	XRBL Schema Document
*101.CAL	XRBL Calculation Linkbase Document

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Exhibit Number	Description
*101.LAB	XRBL Label Linkbase Document
*101.PRE	XRBL Presentation Linkbase Document
*101.DEF	XRBL Definition Linkbase Document

* Filed herewith
\+ Management contract or compensatory plan or arrangement.

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ANNEX E

QUARTERLY REPORT ON FORM 10-Q FOR THE FISCAL QUARTER ENDED SEPTEMBER 30, 2014

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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 September 30, 2014

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

Sanchez Production 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

Constellation Energy Partners LLC

(Former name, former address and former fiscal year, if changed since last report)

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 November 10, 2014: 28,735,703 units.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

SANCHEZ PRODUCTION PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)

(In thousands, except per unit data)

(Unaudited)

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Revenues				
Natural gas sales	$ 9,153	$ 7,328	$ 21,752	$ 18,745
Oil sales	11,402	4,680	21,784	13,497
Liquids sales	841	123	1,690	377
Total revenues (See Note 5)	21,396	12,131	45,226	32,619
Expenses:				
Operating expenses:				
Lease operating expenses	5,296	5,191	15,598	13,332
Cost of sales	404	323	1,198	1,122
Production taxes	796	731	2,563	1,840
General and administrative	3,780	3,015	12,942	11,156
(Gain)/loss on sale of assets		31	(23)	8
Depreciation, depletion and amortization	4,836	5,491	13,206	15,056
Asset impairments	43		237	
Accretion expense	151	163	451	409
Total operating expenses	15,306	14,945	46,172	42,923
Other expenses (income)				
Interest expense	511	420	1,569	2,636
Other income	(76)	23	(220)	(149)
Total other expenses	435	443	1,349	2,487
Total expenses	15,741	15,388	47,521	45,410
Income (loss) from continuing operations	5,655	(3,257)	(2,295)	(12,791)
Loss from discontinued operations				(2,686)
Net income (loss)	$ 5,655	$ (3,257)	$ (2,295)	$ (15,477)

Earnings (loss) per unit (See Note 2)								
Earnings (loss) from continuing operations per unit								
Class A units Basic	$	0.23	$	(0.06)	$	(0.05)	$	(0.36)
Class B units Basic	$	0.19	$	(0.12)	$	(0.08)	$	(0.52)
Class A units Diluted	$	0.23	$	(0.06)	$	(0.05)	$	(0.36)
Class B units Diluted	$	0.19	$	(0.12)	$	(0.08)	$	(0.52)
Loss from discontinued operations per unit								
Class A units Basic and diluted	$		$		$		$	(0.08)
Class B units Basic and diluted	$		$		$		$	(0.11)
Net earnings (loss) per unit								
Class A units Basic	$	0.23	$	(0.06)	$	(0.05)	$	(0.44)
Class B units Basic	$	0.19	$	(0.12)	$	(0.08)	$	(0.63)
Class A units Diluted	$	0.23	$	(0.06)	$	(0.05)	$	(0.44)
Class B units Diluted	$	0.19	$	(0.12)	$	(0.08)	$	(0.63)
Weighted Average Units Outstanding								
Class A units Basic		484,505		1,135,725		857,201		703,883
Class B units Basic		28,552,568		26,071,909		28,358,591		24,238,279
Class A units Diluted		484,505		1,135,725		857,201		703,883
Class B units Diluted		28,660,878		26,071,909		28,358,591		24,238,279
Distributions declared and paid per unit	$		$		$		$	

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ PRODUCTION PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Balance Sheets

(In thousands, except unit data)

	September 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 9,671	$ 4,894
Restricted cash (See Note 2)	1,748	
Accounts receivable, net (See Note 2)	6,958	6,678
Prepaid expenses	1,678	2,547
Risk management assets (See Note 5)	4,528	9,141
Total current assets	24,583	23,260
Oil and natural gas properties (See Note 6)		
Oil and natural gas properties, equipment and facilities	645,222	639,156
Material and supplies	1,056	1,054
Less accumulated depreciation, depletion, amortization, and impairments	(508,208)	(495,215)
Net oil and natural gas properties	138,070	144,995
Other assets		
Debt issue costs (net of accumulated amortization of $9,075 and $9,003, respectively)	761	824
Risk management assets (See Note 5)	1,001	1,461
Restricted cash (See Note 2)		1,748
Other non-current assets	1,917	2,245
Total assets	$ 166,332	$ 174,533
LIABILITIES AND MEMBERS EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 75	$ 12
Accrued liabilities	7,862	12,763
Royalty payable	1,172	1,242
Risk management liabilities (see Note 5)	245	
Total current liabilities	9,354	14,017
Other liabilities		
Asset retirement obligation	10,085	9,513
Other non-current liabilities		1,398
Debt (See Note 7)	51,950	50,700

Total other liabilities		62,035		61,611
Total liabilities		71,389		75,628
Commitments and contingencies (See Note 9)				
Members equity				
Class A units, 484,505 and 1,615,017 units authorized, issued and outstanding, respectively		1,694		2,591
Class B units, 28,848,785 and 28,848,785 units authorized, respectively, and 28,735,703 and 28,462,185 issued and outstanding, respectively		93,249		96,314
Total members equity		94,943		98,905
Total liabilities and members equity	$	166,332	$	174,533

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ PRODUCTION PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(In thousands)

(Unaudited)

	Nine months ended September 30, 2014	2013
Cash flows from operating activities:		
Net loss	$ (2,295)	$ (15,477)
Adjustments to reconcile net loss to cash provided by operating activities		
Depreciation, depletion and amortization	13,206	15,056
Asset impairments (See Note 6)	237	
Amortization of debt issuance costs	199	1,228
Accretion expense	451	409
Equity earnings in affiliate	(147)	(224)
(Gain)/loss from disposition of property and equipment	(23)	8
Bad debt expense	80	44
Mark-to-market on derivatives:		
Total (gains) losses	1,134	(371)
Cash settlements	4,184	8,006
Unit-based compensation programs	1,216	828
Discontinued operations		2,686
Changes in Assets and Liabilities:		
Decrease in accounts receivable	(359)	(1,212)
(Increase) decrease in prepaid expenses	869	(110)
(Increase) decrease in other assets	3	(1,107)
Increase (decrease) in accounts payable	63	(434)
Decrease in accrued liabilities	(4,666)	(1,614)
Decrease in royalty payable	(70)	(54)
Increase (decrease) in other liabilities	(1,398)	1,114
Net cash provided by continuing operations	12,684	8,776
Net cash provided by discontinued operations		1,062
Net cash provided by operating activities	12,684	9,838
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash acquired	(1,351)	(20,221)
Development of oil and natural gas properties	(5,025)	(12,564)
Proceeds from sale of assets	58	58,987
Distributions from equity affiliate	180	135

Net cash provided by (used in) continuing operations	(6,138)	26,337
Net cash used in discontinued operations		
Net cash provided by (used in) investing activities	(6,138)	26,337
Cash flows from financing activities:		
Proceeds from issuance of debt	5,750	16,894
Repayment of debt	(4,500)	(50,194)
Repurchase of Class A, Class C and Class D interests	(2,468)	
Units tendered by employees for tax withholdings	(415)	(185)
Debt issue costs	(136)	(925)
Net cash used in continuing operations	(1,769)	(34,410)
Net cash used in discontinued operations		
Net cash used in financing activities	(1,769)	(34,410)
Net increase in cash and cash equivalents	4,777	1,765
Cash and cash equivalents, beginning of period	4,894	1,959
Cash and cash equivalents, end of period	$ 9,671	$ 3,724
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ (219)	$ 333
Cash paid during the period for interest	$ (1,379)	$ (1,405)

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ PRODUCTION PARTNERS LLC and SUBSIDIARIES

Condensed Consolidated Statements of Changes in Members Equity

(In thousands, except unit data)

(Unaudited)

	Class A		Class B		Accumulated Other Comprehensive Income (Loss)	Total Members Equity
	Units	Amount	Units	Amount		
Balance, December 31, 2013	1,615,017	$ 2,591	28,462,185	$ 96,314	$	$ 98,905
Distributions						
Units tendered by employees for tax withholding			(160,182)	(415)		(415)
Unit-based compensation programs			433,700	1,216		1,216
Cancellation of units (See Note 9)	(1,130,512)	(851)		(1,617)		(2,468)
Net income (loss)		(46)		(2,249)		(2,295)
Balance, September 30, 2014	484,505	$ 1,694	28,735,703	$ 93,249	$	$ 94,943

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ PRODUCTION PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Sanchez Production Partners LLC (SPP, we, us, our or the Company) (formerly Constellation Energy Partners LLC) was organized as a limited liability company on February 7, 2005, under 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 SPP . We are currently focused on the acquisition, development and production of oil and natural gas properties and other integrated assets. Our proved reserves are currently located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas and in Texas and Louisiana.

Through subsidiaries, Sanchez Oil & Gas Corporation (SOG) owns a portion of our outstanding units. As of September 30, 2014, Sanchez Energy Partners I, LP (SEP I), a subsidiary of SOG, owned 484,505, or 100%, of our Class A units and 5,139,345, or 17.9%, of our Class B common units.

On October 3, 2014, Constellation Energy Partners LLC (CEP) changed its name to Sanchez Production Partners LLC. The name change was effected pursuant to Section 18-202 of the Delaware Limited Liability Company Act (the DLLCA) by filing a Fourth Certificate of Amendment to Certificate of Formation with the Secretary of State of the State of Delaware. Under the DLLCA and the Company s Second Amended and Restated Operating Agreement, as amended, the name change did not require approval of the Company s unitholders.

On June 26, 2014, we settled the lawsuit brought by Constellation Energy Partners Holdings, LLC (CEPH), a subsidiary of Exelon Corporation, against us in the Court of Chancery of the State of Delaware (the Exelon Litigation). In conjunction with the settlement, we paid CEPH $1.65 million in exchange for all of the Class C management incentive interests and Class D interests held by CEPH, which were all of such interests issued by SPP. Effective with the acquisition of these interests from CEPH, we cancelled the Class C management incentive interests and Class D interests.

On May 8, 2014, the Company and SP Holdings, LLC (the Manager), an affiliate of SOG, entered into a Shared Services Agreement (the Services Agreement) pursuant to which, as of July 1, 2014, the Manager provides services that the Company requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals and acquisition, disposition and financing services.

Basis of Presentation

These unaudited condensed consolidated financial statements include the accounts of SPP 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.

These unaudited condensed consolidated financial statements have been prepared pursuant to the rules of the Securities and Exchange Commission (SEC). Certain information and footnote disclosures, normally included in annual financial statements prepared in accordance with accounting principles generally accepted in

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the United States (U.S. GAAP), have been condensed or omitted pursuant to those rules and regulations. We believe that the disclosures made are adequate to make the information presented not misleading. In the opinion of management, all adjustments, consisting only of normal recurring adjustments, necessary to fairly state the financial position, results of operations and cash flows with respect to the interim consolidated financial statements have been included. The results of operations for the interim periods are not necessarily indicative of the results for the entire year. The year-end balance sheet data was derived from audited financial statements, but does not include all disclosures required by U.S. GAAP.

These unaudited condensed consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto of SPP and our subsidiaries included in our Annual Report on Form 10-K for the year ended December 31, 2013, which was filed with the SEC on March 27, 2014.

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the condensed consolidated financial statements and accompanying footnotes. These estimates and the underlying assumptions affect the amounts of assets and liabilities reported, disclosures about contingent assets and liabilities and reported amounts of revenues and expenses. The estimates that are particularly significant to our financial statements include estimates of our reserves of oil, natural gas and natural gas liquids (NGL); future cash flows from oil and natural gas properties; depreciation, depletion and amortization; asset retirement obligations; certain revenues and operating expenses; fair values of commodity derivatives and fair values of assets and liabilities. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management s best estimates and judgment. Management evaluates its estimates and assumptions on an on-going basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from the estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

Reclassifications

Certain reclassifications have been made to the prior period to conform to the current period presentation. These reclassifications had no effect on total assets, total liabilities, total unitholders equity, net income or net cash provided by or used in operating, investing or financing activities.

Discontinued Operations

In February 2013, we sold all of our Robinson s Bend Field assets in the Black Warrior Basin in Alabama. The related results of operations and cash flows have been classified as discontinued operations in the condensed consolidated statements of operations, balance sheets, statements of cash flows and consolidated financial information for the nine months ended September 30, 2013. Unless otherwise indicated, information presented in the Notes to Condensed Consolidated Financial Statements relates only to the Company s continuing operations. Information related to discontinued operations is included in Note 3. *Acquisitions and Divestiture.*

New Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board (the FASB), which are adopted by us as of the specified effective date. Unless otherwise discussed, management believes that the impact of recently issued standards, which are not effective, will not have a material impact on our condensed consolidated financial statements upon adoption.

In April 2014, the FASB issued Accounting Standards Update (ASU) No. 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. This guidance changes the definition of a

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discontinued operation to include only those disposals of components of an entity that represent a strategic shift that has or will have a major effect on an entity s operations and financial results. This guidance is effective prospectively for fiscal years beginning after December 15, 2014. The effects of this accounting standard on our financial position, results of operations and cash flows are not yet known.

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606).* This guidance outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods and services. The new guidance is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is not permitted. The guidance may be applied retrospectively to each prior period presented or retrospectively with the cumulative effect recognized as of the date of initial application. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements, but do not expect the impact to be material.

In August 2014, the FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity s Ability to Continue as a Going Concern.* This guidance creates a new subtopic ASC 205-40, Presentation of Financial Statements Going Concern, and provides guidance about management s responsibility to evaluate whether there is a substantial doubt about an entity s ability to continue as a going concern and to provide related footnote disclosures. The requirements in this guidance are effective for the annual period ending after December 15, 2016, which is fiscal 2017 for us, and for annual and interim periods thereafter. Early application is permitted. We acknowledge this new guidance and will comply with the disclosure requirements, if applicable, beginning in fiscal 2017.

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, 2013.

Earnings per Unit

Basic earnings per unit (EPU) is computed by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. To determine net income (loss) allocated to each class of ownership (Class A and Class B), we first allocate net income (loss) in accordance with the amount of distributions made for the period by each class, if any. The remaining net income (loss) is allocated to each class with the Class A units receiving 2% and the Class B units receiving 98%.

As of September 30, 2014 and 2013, we had unvested restricted common units outstanding, which were considered dilutive securities. These units will be considered in the diluted weighted average common units outstanding number in periods of net income. In periods of net losses, these units are excluded from the diluted weighted average common unit outstanding number as they are not participating securities.

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The following table presents our calculation of basic and diluted units outstanding for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Weighted average units outstanding during period:				
Class A units Basic	484,505	1,135,725	857,201	703,883
Class B units Basic	28,552,568	26,071,909	28,358,591	24,238,279
	29,037,073	27,207,634	29,215,792	24,942,162
Weighted average units outstanding during period:				
Class A units Diluted	484,505	1,135,725	857,201	703,883
Class B units Diluted	28,660,878	26,071,909	28,358,591	24,238,279
	29,145,383	27,207,634	29,215,792	24,942,162

At September 30, 2014, we had 108,310 Class B common units that were restricted unvested common units granted and outstanding. These units were included in the diluted weighted average common unit outstanding number for the three months ended September 30, 2014, but were excluded from the nine months ended September 30, 2014.

The following table presents our basic and diluted income per unit for the three months ended September 30, 2014 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Income from continuing operations	$ 5,655		
Distributions		$	$
Assumed net income to be allocated	$ 5,655	$ 113	$ 5,542
Basic and diluted earnings per unit		$ 0.23	$ 0.19

The following table presents our basic and diluted loss per unit for the three months ended September 30, 2013 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Loss from continuing operations	$ (3,257)		

Distributions		$	$
Assumed allocation of loss from continuing operations	(3,257)	(65)	(3,192)
Discontinued operations			
Assumed net loss to be allocated	$ (3,257)	$ (65)	$ (3,192)
Basic and diluted loss from continuing operations per unit		$ (0.06)	$ (0.12)
Basic and diluted loss from discontinued operations per unit		$	$
Basic and diluted loss per unit		$ (0.06)	$ (0.12)

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The following table presents our basic and diluted loss per unit for the nine months ended September 30, 2014 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Loss from continuing operations	$ (2,295)		
Distributions		$	$
Assumed net loss to be allocated	$ (2,295)	$ (46)	$ (2,249)
Basic and diluted loss per unit		$ (0.05)	$ (0.08)

The following table presents our basic and diluted loss per unit for the nine months ended September 30, 2013 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Loss from continuing operations	$ (12,791)		
Distributions		$	$
Assumed allocation of loss from continuing operations	(12,791)	(256)	(12,535)
Discontinued operations	(2,686)	(54)	(2,632)
Assumed net loss to be allocated	$ (15,477)	$ (310)	$ (15,167)
Basic and diluted loss from continuing operations per unit		$ (0.36)	$ (0.52)
Basic and diluted loss from discontinued operations per unit		$ (0.08)	$ (0.11)
Basic and diluted loss per unit		$ (0.44)	$ (0.63)

Cash

All highly liquid investments with original maturities of three months or less are considered cash. Checks-in-transit are included in our consolidated balance sheets as accounts payable or as a reduction of cash, depending on the type of bank account the checks were drawn on. There were no checks-in-transit reported in accounts payable at September 30, 2014 and December 31, 2013.

Restricted Cash

Restricted cash, at September 30, 2014 and December 31, 2013, of $1.7 million was being held in escrow. Of this balance, $0.6 million is related to a vendor dispute, and will remain in the escrow account until the dispute has been resolved. The remaining amount of $1.1 million is related to the sale of our Robinson s Bend Field assets in the Black

Warrior Basin of Alabama. These funds will remain in escrow for a period ending February 28, 2015, pending certain post-closing conditions. The restricted cash was classified as a non-current asset at December 31, 2013, but was reclassified to a current asset at September 30, 2014, based on the conditions of the cash held in the account.

Accounts Receivable, Net

Our accounts receivable are primarily from purchasers of oil and natural gas and counterparties to our financial instruments. Oil receivables are generally collected within 30 days after the end of the month. Natural gas receivables are generally collected within 60 days after the end of the month. We review all outstanding accounts receivable balances and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserves until substantially all collection efforts have been exhausted. At September 30, 2014 and December 31, 2013, we had an allowance for doubtful accounts receivable of $0.2 million and $0.1 million, respectively.

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3. ACQUISITIONS AND DIVESTITURE

Sale of Robinson s Bend Field Assets

On February 28, 2013, we sold all of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama for $63.0 million, subject to closing adjustments that amounted to approximately $4.0 million. We recorded a loss on the sale of approximately $3.1 million in the nine months ended September 30, 2013. The sale of the Robinson s Bend Field assets was initiated to provide the financial flexibility necessary to support our efforts for pursuing opportunities and further developing our properties in the Mid-Continent region, as well as reducing our outstanding debt.

The following amounts relating to the Robinson s Bend Field assets have been reported as discontinued operations in the condensed consolidated statements of operations for the three and nine months ended September 30, 2013 (in thousands):

	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
Revenues	$	$ 2,304
Loss from discontinued operations	$	$ (2,686)

See Note 2 for information regarding earnings per unit, including earnings per unit data relating to loss from discontinued operations.

The condensed consolidated statements of cash flows reflect discontinued operations for the nine months ended September 30, 2013.

Acquisition of Oil, Natural Gas and Natural Gas Liquids Properties from SEP I

On August 9, 2013, we acquired oil, natural gas and NGL assets in Texas and Louisiana from SEP I for a purchase price of $30.4 million. In conjunction with the acquisition, SEP I received $20.1 million in cash; 1,130,512 Class A units, which represented 70.0% of the total Class A units outstanding as of such date, and 4,724,407 Class B units, which represented 16.6% of the total Class B units outstanding as of such date. The cash portion of the transaction was financed with cash on hand and a borrowing of $16.7 million under our reserve-based credit facility.

The acquired assets included 67 producing wells in Texas and Louisiana. The primary factors considered by management in acquiring the SEP I properties included the belief that these wells provide an opportunity to significantly increase our reserves, production volumes and drilling portfolio, while maintaining our focus of increasing our oil-weighted assets. The SEP I properties also provide us with access to exploitation and development potential.

The following table summarizes the estimated values of assets acquired and liabilities assumed effective August 1, 2013 (in thousands):

	August 1, 2013

Oil and natural gas properties, equipment and facilities	$	31,497
Asset retirement obligation		(1,088)
Net assets acquired	$	30,409

We accounted for our acquisition of oil and natural gas properties using the purchase method of accounting for business combinations, and therefore we estimated the fair value of the assets acquired and the liabilities assumed as of the acquisition date. The fair value measurements of assets acquired and liabilities assumed were based on inputs that were not observable in the market and therefore represent Level 3 inputs. The fair value of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) estimated future cash flows and (v) a market-based weighted cost of capital rate. These inputs require significant judgments and estimates by the Company s management at the time of the valuation and are the most sensitive and subject to change.

Pro Forma Information

The following supplemental pro forma information presents consolidated results of operations as if the acquisition of the SEP I properties had occurred on January 1, 2013. The supplemental unaudited pro forma information was derived from a) our historical consolidated statements of operations and b) the statements of operations of SEP I. This information does not purport to be indicative of results of operations that would have occurred had the acquisition occurred on January 1, 2013, nor is such information indicative of any expected future results of operations.

(In thousands, except per unit data)		**Pro Forma Three Months Ended September 30, 2013**		**Pro Forma Nine Months Ended September 30, 2013**
Revenue	$	16,067	$	45,383
Loss from continuing operations	$	(998)	$	(5,448)
Discontinued operations	$		$	(2,686)
Net loss	$	(998)	$	(8,134)
Loss from continuing operations per unit				
Class A units Basic and diluted	$	(0.01)	$	(0.07)
Class B units Basic and diluted	$	(0.03)	$	(0.19)
Discontinued operations per unit				
Class A units Basic and diluted	$		$	(0.03)
Class B units Basic and diluted	$		$	(0.09)
Net loss per unit				
Class A units Basic and diluted	$	(0.01)	$	(0.10)
Class B units Basic and diluted	$	(0.03)	$	(0.28)
Weighted average units outstanding				
Class A units Basic and diluted		1,614,964		1,614,918
Class B units Basic and diluted		28,074,647		28,045,494

Acquisition of Oil and Natural Gas Properties

On April 9, 2014, we acquired a 20% working interest in nine producing wells and other assets for $1.4 million. These assets are located in LaSalle Parish, Louisiana and are operated by SOG. This purchase became effective May 1, 2014. The impact of the acquisition of these properties was not material to our consolidated financial statements, so no pro forma information for this acquisition is provided.

4. FAIR VALUE MEASUREMENTS

We measure certain financial assets and liabilities at fair value. Fair value is defined as an exit price which represents the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in valuing an asset or liability. The accounting guidance also requires the use of valuation techniques to measure fair value that maximize the use of observable inputs and minimize the use of unobservable inputs. As a basis for considering such assumptions and inputs, a fair value hierarchy has been established which identifies and prioritizes three levels of inputs to be used in measuring fair value.

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The three levels of the fair value hierarchy are as follows:

Level 1 Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 Inputs other than the quoted prices in active markets that are observable either directly or indirectly, including: quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar assets and liabilities in markets that are not active or other inputs that are observable or can be corroborated by observable market data.

Level 3 Unobservable inputs that are supported by little or no market data and require the reporting entity to develop its own assumptions.

As required by accounting guidance for fair value measurements, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2014 (in thousands):

	Fair Value Measurements at September 30, 2014				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at September 30, 2014
Risk Management Assets	$	$ 5,663	$	$ (134)	$ 5,529
Risk Management Liabilities		(379)		134	(245)
Total Net Assets and Liabilities	$	$ 5,284	$	$	$ 5,284

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 (in thousands):

	Fair Value Measurements at December 31, 2013				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at December 31, 2013
Risk Management Assets	$	$ 11,577	$	$ (975)	$ 10,602
Risk Management Liabilities		(975)		975	

Total Net Assets and Liabilities	$	$ 10,602	$	$	$ 10,602

As of September 30, 2014, the estimated fair value of cash and cash equivalents, accounts receivable, other current assets and current liabilities approximated their carrying value due to their short-term nature.

Fair Value of Financial Instruments

Fair value guidance requires certain fair value disclosures, such as those on our debt and derivatives, to be presented in both interim and annual reports. The estimated fair value amounts of financial instruments have been determined using available market information and valuation methodologies described below.

Reserve-Based Credit Facility We believe that 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

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for debt with similar terms. The debt is classified as a Level 2 input 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 further in Note 7.

Derivative Instruments 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 inputs. 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.

5. DERIVATIVE AND FINANCIAL INSTRUMENTS

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. These transactions are normally price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never our intention to enter into derivative contracts for speculative trading purposes.

Under ASC Topic 815, *Derivatives and Hedging*, all derivative instruments are recorded on the condensed consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We will net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives fair values are recognized currently in earnings unless specific hedge accounting criteria are met. We have not elected to designate any of our current derivative contracts as hedges; however, changes in the fair value of all of our derivative instruments are recognized in earnings and included as realized and unrealized gains (losses) on derivative instruments in the condensed consolidated statements of operations.

As of September 30, 2014, we had the following derivative contracts in place for the periods indicated, all of which 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,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2014							1,610,000	$ 5.75	1,610,000	$ 5.75
2015	1,215,420	$ 4.25	1,153,487	$ 4.25	1,096,023	$ 4.26	1,050,219	$ 4.26	4,515,149	$ 4.25
2016	1,010,633	$ 4.21	967,290	$ 4.21	923,541	$ 4.21	893,568	$ 4.21	3,795,032	$ 4.21
									9,920,181	

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MTM Fixed Price Basis Swaps Enable Gas Transmission, LLC (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,		September 30,		December 31,		Total	
	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $	Volume	Weighted Average $
2014							1,047,963	$ 0.39	1,047,963	$ 0.39
									1,047,963	

MTM Fixed Price Basis Swaps West Texas Intermediate (WTI)

	For the quarter ended (in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2014							73,005	$ 95.78	73,005	$ 95.78
2015	69,479	$ 90.99	66,183	$ 91.02	63,025	$ 91.05	60,143	$ 91.09	258,830	$ 91.04
2016	57,420	$ 85.64	54,879	$ 85.64	52,474	$ 85.64	50,197	$ 85.64	214,970	$ 85.64
									546,805	

The table below outlines the classification of our derivative financial instruments on the condensed consolidated balance sheet (in thousands):

Derivative Type	Location of Asset/(Liability) on Balance Sheet	Fair Value of Asset/(Liability) on Balance Sheet September 30, 2014	December 31, 2013
Commodity MTM	Risk management assets current	$ 4,617	$ 10,043
Commodity MTM	Risk management assets non-current	1,046	1,534
	Total gross assets	5,663	11,577
Commodity MTM	Risk management liabilities current	(334)	(902)
Commodity MTM	Risk management liabilities non-current	(45)	(73)
	Total gross liabilities	(379)	(975)
	Total net assets and liabilities	$ 5,284	$ 10,602

The effect of derivative instruments on our condensed consolidated statements of operations was as follows (in thousands):

	Location of Gain/(Loss)	Amount of Gain/(Loss) in Income For the Three Months Ended September 30,	
Derivative Type	**in Income**	**2014**	**2013**
Commodity Mark-to-Market	Oil and natural gas sales	$ 7,671	$ (406)
Interest Rate Mark-to-Market	Interest expense		
	Total	$ 7,671	$ (406)

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Derivative Type		Location of Gain/(Loss) in Income	Amount of Gain/(Loss) in Income For the Nine Months Ended September 30, 2014	2013
Commodity	Mark-to-Market	Oil and natural gas sales	$ (1,134)	$ 436
Interest Rate	Mark-to-Market	Interest expense		(65)
		Total	$ (1,134)	$ 371

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with two counterparties. We generally execute commodity derivative instruments under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election.

We monitor the creditworthiness of our counterparties; however, we are not able to predict sudden changes in counterparties creditworthiness. In addition, if such changes are sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of our counterparties not perform, we may not realize the benefit of some of our derivative instruments with lower commodity prices and may incur losses. We include a measure of counterparty credit risk in our estimates of the fair values of the derivative instruments in an asset position.

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 our 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 September 30, 2014 and December 31, 2013, the impact of non-performance credit risk on the valuation of our net assets from counterparties was not significant, and the entire amount was reflected as a decrease to our non-cash mark-to-market gain, respectively.

Hedge Liquidation and Repositioning

In the first quarter of 2013, we liquidated or repositioned certain of our hedges. In connection with the sale of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama, we liquidated 395,218 MMbtu of NYMEX swaps in 2013 and 1,634,530 MMbtu of NYMEX swaps in 2014 at a cost of $0.3 million. In addition, we reduced our outstanding NYMEX swap positions in 2013 by 1,041,814 MMbtu by executing offsetting trades with one of our counterparties at a fixed price of $3.66 per Mcf. These transactions ensured that our outstanding derivative positions in future periods are lower than our expected future natural gas production in those periods. We also amended a 2014 to 2015 oil trade with one of our hedge counterparties to lower the stated swap price from $98.10 to $93.50 per barrel, on a total of 58,157 barrels of oil. We received proceeds of approximately $0.2 million upon execution of the amendment. The proceeds were used for working capital purposes.

In March 2013, we reduced our outstanding interest rate swaps that fix our LIBOR rate through 2014 to $30 million, which increased our interest rate swap settlements by $2.1 million. This position was terminated in May 2013 resulting in an offsetting non-cash gain in our mark-to-market interest swap activities.

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6. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties consisted of the following (in thousands):

	September 30, 2014	December 31, 2013
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 642,923	$ 636,816
Unproved property	1,548	1,589
Total property costs	644,471	638,405
Materials and supplies	1,056	1,054
Land	751	751
Total	646,278	640,210
Less: Accumulated depreciation, depletion, amortization and impairments	(508,208)	(495,215)
Oil and natural gas properties and equipment, net	$ 138,070	$ 144,995

Depreciation, depletion, amortization and impairments consisted of the following (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
DD&A of oil and natural gas-related assets	$ 4,836	$ 5,491	$ 13,206	$ 15,056
Asset impairments	43		237	
Total	$ 4,879	$ 5,491	$ 13,443	$ 15,056

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

For the nine months ended September 30, 2014, our non-cash impairment charges were $0.2 million to impair the value of our oil and natural gas fields in Texas and Louisiana, with an immaterial amount being recorded during the three months ended September 30, 2014. For the three and nine months ended September 30, 2013, we did not have an impairment to record. The 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.

Asset Sales

During each of the three and nine months ended September 30, 2014 and September 30, 2013, we sold miscellaneous surplus equipment for less than $0.1 million resulting in an immaterial gain on the asset sales.

Useful Lives

Our furniture, fixtures and equipment are depreciated over a life of one to seven years, buildings are depreciated over a life of 20 years and pipeline and gathering systems are depreciated over a life of 25 to 40 years.

Exploration and Dry Hole Costs

We recorded no exploration and dry hole costs for the three and nine months ended September 30, 2014 and 2013, 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.

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7. DEBT

Reserve-Based Credit Facility

In May 2013, we refinanced our $350.0 million reserve-based credit facility with Societe Generale as administrative and collateral agent and a syndicate of lenders, extending its maturity to May 30, 2017 and increasing our borrowing base from $37.5 million to $55.0 million. On May 6, 2014, our borrowing base under the reserve-based credit facility was increased to $70.0 million. Borrowings under the reserve-based credit facility are secured by various mortgages of oil and natural gas properties that we and certain of our subsidiaries own, as well as various security and pledge agreements among us and certain of our subsidiaries and the administrative agent. The 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 September 30, 2014, we had borrowed $52.0 million under our reserve-based credit facility and our borrowing base was $70.0 million. At September 30, 2014, the lenders and their percentage commitments in the reserve-based credit facility were Societe Generale (36.36%), OneWest Bank, FSB (36.36%) and BOKF NA, dba Bank of Oklahoma (27.28%).

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 September 30, 2014, no letters of credit were outstanding.

At our election, interest for borrowings is 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 is 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 and make certain loans, acquisitions, capital expenditures and investments. The reserve-based credit facility limits our ability to pay distributions to unitholders and permits us to hedge our projected monthly production, as discussed below, and the interest rate on our borrowings.

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 3.5 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 Accounting Standards Codification (ASC) Topic 815, *Derivatives and Hedging*; ASC Topic 410, *Asset Retirement and Environmental Obligations* and ASC Topic 360, *Property, Plant and*

Equipment. All financial covenants are calculated using our consolidated financial information and are discussed below.

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. These events have not both occurred, so a change in control had not occurred as of September 30, 2014. 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 our 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. As of September 30, 2014, 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 SOG s ownership in us.

Compliance with Debt Covenants

At September 30, 2014, we were in compliance with the financial covenants contained in our reserve-based credit facility. We monitor compliance on an on-going basis.

If we are unable to remain in compliance with the financial covenants contained in our reserve-based credit facility or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of our reserve-based credit facility, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated covenants from the lenders, but there is no assurance that such waivers would be granted.

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 September 30, 2014, our borrowing base was $70.0 million. The borrowing base is re-determined semi-annually, and may be re-determined at our request more

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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 pricing 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.

Funds Available for Borrowing

As of September 30, 2014 and December 31, 2013, we had $52.0 million and $50.7 million, respectively, in outstanding debt under our reserve-based credit facility. As of September 30, 2014, we had $18.0 million available under our reserve-based credit facility.

Debt Issue Costs

As of September 30, 2014, our unamortized debt issue costs were approximately $0.8 million. These costs are being amortized over the life of our reserve-based credit facility. At December 31, 2013, our unamortized debt issue costs were approximately $0.8 million.

8. 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 oil and natural gas wells, and decommissioning of oil and natural gas gathering and other 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 (in thousands):

	September 30, 2014	December 31, 2013
Asset retirement obligation, beginning balance	$ 9,513	$ 7,665
Liabilities added from acquisitions	79	1,088
Liabilities added from drilling	42	244
Settlements		(3)
Accretion expense	451	519
Asset retirement obligation, ending balance	$ 10,085	$ 9,513

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 obligations. At September 30, 2014 and December 31, 2013, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing asset retirement obligations.

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9. COMMITMENTS AND CONTINGENCIES

On August 30, 2013, a lawsuit was filed in the Chancery Court of the State of Delaware by Constellation Energy Partners Management, LLC (CEPM), Gary M. Pittman and John R. Collins against the Company, certain of its officers and managers, SOG and SEP I (the PostRock Litigation) in connection with the Company s closing on August 9, 2013 of the purchase of oil and natural gas properties from SEP I and the issuance of units in connection therewith. The plaintiffs contended, among other things, that the issuance of the units to SEP I in connection with the acquisition was not permitted under the Company s operating agreement, that Messrs. Pittman and Collins should not have been removed as the Class A managers of the Company s board of managers, and that SEP I, SOG and our current Class A managers participated in bad faith conduct of the other defendants and interfered with CEPM s contractual rights under the Company s operating agreement. The plaintiffs alleged claims against the Company and certain of its managers and officers relating to breach of contract, breach of the duty of good faith, and breach of the implied covenant of good faith and fair dealing; the plaintiffs also alleged aiding and abetting and tortuous interference claims against SOG, SEP I and our current Class A managers. The plaintiffs sought, among other things, declaratory relief reappointing Messrs. Pittman and Collins to the Company s board of managers and removing our current Class A managers therefrom, and an injunction against the Company taking any further action outside the ordinary course of business during the pendency of the litigation, declaratory relief rescinding the units issued by the Company to SEP I, declaratory relief that CEPM had sole voting power with respect to the outstanding Class A units, declaratory relief that the Company s officers and managers breached fiduciary and contractual duties and were not entitled to indemnification from the Company as a result thereof, and monetary damages. On March 31, 2014, the parties to the lawsuit reached a settlement agreement and the lawsuit was subsequently dismissed. As a result of the settlement, the Class A units acquired by SEP I in the August 2013 transaction were returned to SPP and cancelled in exchange for $0.8 million; CEPM transferred 100% of its Class A units and 414,938 of SPP s Class B units to SEP I in exchange for an aggregate payment of $1.0 million from SEP I, and SPP paid $6.5 million to CEPM. In addition, pursuant to the terms of the settlement, CEPM agreed to sell its remaining Class B units over the next nine months, with SEP I providing up to a $5.0 million backstop payment to CEPM to the extent proceeds received by CEPM from such sale do not meet or exceed a specified amount. As a result of the settlement, the settling parties filed a stipulation in the Court of Chancery of the State of Delaware seeking to lift the preliminary injunction issued on December 3, 2013, and the litigation was dismissed with prejudice. The settlement also included mutual releases between the plaintiffs and defendants. In connection with the settlement, we received $1.25 million on April 10, 2014, under our directors and officers insurance policy.

On February 28, 2014, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPH against the Company (the Exelon Litigation) seeking repayment of suspended distributions in relation to the Class D Interests held by CEPH. In 2006, Constellation Holding, Inc (CHI), which merged with and into CEPH in December 2012, purchased the Company s Class D Interests for $8.0 million. The $8.0 million was to be repaid to CEPH in quarterly distributions of $333,333.33 over a period of six years; however, these distributions could be temporarily suspended if a dispute arose over pricing formulas related to the sale of natural gas from the Robinson s Bend properties. A dispute arose, so the distributions were suspended pursuant to the Company s operating agreement and never reinstated. CEPH contended, among other things, that the Company breached its contract to pay the quarterly distributions, acted in bad faith and received unjust enrichment by suspending the quarterly distributions. On June 26, 2014, the parties to the lawsuit reached a settlement agreement and the lawsuit was subsequently dismissed. In conjunction with the settlement, we paid CEPH $1.65 million in exchange for all of the Class C management incentive interests and the Class D interests held by CEPH, which accounted for all such interests issued by SPP. Effective with the acquisition from CEPH, we cancelled the Class C management incentive interests and Class D interests.

10. RELATED PARTY TRANSACTIONS

Unit Ownership

SOG, through a subsidiary, owns a portion of our outstanding units. As of September 30, 2014, SEP I, a subsidiary of SOG, owned 484,505, or 100%, of our Class A units and 5,139,345, or 17.9%, of our Class B common units.

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Sanchez-Related Announcements

In August 2013, SEP I acquired certain of our Class A units and Class B common units and one Class Z unit in one transaction which represented a 19.2% ownership interest in us at September 30, 2014. These units were issued to SEP I, along with cash, in exchange for oil and natural gas properties located in Texas and Louisiana.

In August 2013, the Company also entered into a Registration Rights Agreement with SEP I pursuant to which the Company granted to SEP I certain registration rights related to the unit consideration thereunder. Under the Registration Rights Agreement, the Company granted SEP I demand registration rights with respect to the preparation and filing with the SEC of one or more registration statements for the purpose of registering the resale of the securities that will be registered.

On May 8, 2014, the Company and the Manager, an affiliate of SOG, entered into the Services Agreement pursuant to which the Manager provides services that the Company requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals and acquisition, disposition and financing services. In connection with providing the services under the Services Agreement, the Manager receives compensation consisting of: (i) a quarterly fee equal to 0.375% of the value of the Company s properties other than its assets located in the Mid-Continent region, (ii) a $1,000,000 administrative fee, with $500,000 paid on May 8, 2014 and $500,000 paid on July 1, 2014, the date that the Manager provided notice of its commitment to provide services under the Services Agreement (the In-Service Date), (iii) reimbursement for all allocated overhead costs as well as any direct third-party costs incurred and (iv) for each asset acquisition, asset disposition and financing, a fee not to exceed 2% of the value of such transaction. Each of these fees, not including the reimbursement of costs, will be paid in cash unless the Manager elects for such fee to be paid in equity by the Company. In addition, upon the first acquisition of assets from an affiliate of the Manager, the Company is required to amend its operating agreement and issue a new class of incentive distribution right to the Manager.

The Services Agreement has a ten-year term and will be automatically renewed for an additional ten years unless both the Manager and the Company provide notice to terminate the agreement. The Services Agreement can be terminated early (i) by either party at any time after 24 months from the In-Service Date with six months notice to the other party, (ii) by either party if there is an uncured material breach thereunder by the other party or (iii) by the Company if there is a change in control of the Manager and the Company pays the termination payment discussed below. If there is a termination of the Services Agreement other than by either party at the end of the agreement s term or by the Company for a breach by the Manager, then the Company will owe a termination payment to the Manager equal to $5,000,000, plus 5% of the transaction value of all asset acquisitions theretofore consummated; if the Company terminates after the 24-month anniversary of the In-Service Date upon six months notice, the Company will also owe to the Manager all costs and expenses of the Manager that result from such termination. Through September 30, 2014, the Company has paid $0.8 million to SOG under the Services Agreement.

On May 8, 2014, the Company and SOG entered into a Contract Operating Agreement (the Operating Agreement) pursuant to which SOG has agreed either to provide services to operate, develop and produce the Company s oil and natural gas properties or to engage a third-party operator to do so, other than with respect to the Company s properties in the Mid-Continent region. In connection with providing services under the Operating Agreement, SOG will be reimbursed for all direct charges under COPAS.

On May 8, 2014, the Company, the Manager and SOG entered into a Transition Agreement (the Transition Agreement) pursuant to which the Company agreed to make available to the Manager and SOG certain of the Company s employees for SOG or the Manager to provide services under the Services Agreement and Operating agreement. No compensation was paid by any party for the provision or use of employees under the Transition Agreement. All employees remained under the day-to-day control of the Company, and the Company retained the right to terminate employees and had no obligation to hire new employees. SOG had the right to hire any Company employees and thereafter, SOG is responsible for all costs and expenses for such employees. As of the

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In- Service Date, all employees of the Company located in the Houston office became employees of SOG, except for the Chief Executive Officer and the Chief Financial Officer, who remain employees of the Company.

On May 8, 2014, the Company, SOG and certain subsidiaries of the Company entered into a Geophysical Seismic Data Use License Agreement (the License Agreement) pursuant to which SOG provides to the Company a non-exclusive, royalty-free license to use seismic, geophysical and geological information relating to the Company s oil and natural gas properties that is proprietary to SOG and not restricted by agreements that SOG has with landowners or seismic data vendors.

Class Z Unit

SEP I holds the one Class Z unit of SPP. This one unit is a non-voting unit, except for voting as a separate class to approve the issuance of additional Company securities, other than Class B common units, prior to the issuance of such securities. The Class Z unit is a non-economic interest, without any right to participate in distributions or allocations.

11. UNIT-BASED COMPENSATION

We have the following unit-based compensation plans:

We have the 2009 Omnibus Incentive Compensation Plan (Omnibus Plan), which is a plan under which restricted common unit awards are granted to certain employees in Texas. The Omnibus Plan provides for a variety of unit-based and performance-based awards, including unit options, restricted units, unit grants, notional units, unit appreciation rights, performance awards and other unit-based awards. Awards under the Omnibus Plan may be paid in cash, units or any combination thereof as determined by the compensation committee of our board of managers.

Restricted unit activity (number of units) under the Omnibus Plan was as follows:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2013	336,551	$ 3.29
Vested	(171,692)	3.33
Granted		
Returned/Cancelled	(57,214)	3.33
Outstanding at March 31, 2014	107,645	$ 3.20
Vested	(37,653)	2.44
Granted	346,403	2.44
Returned/Cancelled	(15,981)	3.44
Outstanding at June 30, 2014	400,414	$ 2.39
Vested	(236,809)	2.46
Granted		

Returned/Cancelled	(77,187)		2.44
Outstanding at September 30, 2014	86,418	$	3.15

We have the Long-Term Incentive Plan (L-TIP), which is a plan under which restricted common unit awards are granted to certain field employees in Kansas and Oklahoma and to certain employees in Texas.

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Restricted unit activity (number of units) under the L-TIP Plan was as follows:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2013	43,776	$ 2.87
Vested	(16,415)	2.87
Granted		
Returned/Cancelled	(5,469)	2.87
Outstanding at March 31, 2014	21,892	$ 2.87
Vested	(22,028)	2.44
Granted	103,278	2.44
Returned/Cancelled		
Outstanding at June 30, 2014	103,142	$ 2.53
Vested	(60,938)	2.44
Granted		
Returned/Cancelled	(20,312)	2.44
Outstanding at September 30, 2014	21,892	$ 2.87

We recognized approximately $1.2 million and $0.8 million on non-cash compensation expense related to our unit-based compensation plans in the nine months ended September 30, 2014 and September 30, 2013, respectively.

12. DISTRIBUTIONS TO UNITHOLDERS

Beginning in June 2009, we suspended our quarterly distributions to unitholders. For each of the quarterly periods since June 2009, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board of managers for the proper conduct of our business) from which to pay distributions.

13. MEMBERS EQUITY

2014 Equity

At September 30, 2014, we had 484,505 Class A units and 28,735,703 Class B common units outstanding, which included 21,892 unvested restricted common units issued under our L-TIP Plan and 86,418 unvested restricted common units issued under our Omnibus Plan.

At September 30, 2014, we had granted 424,231 common units of the 450,000 common units available under our L-TIP Plan. Of these grants, 402,339 have vested.

At September 30, 2014, we had granted 1,562,687 common units of the 1,650,000 common units available under our Omnibus Plan. Of these grants, 1,476,269 have vested.

For the nine months ended September 30, 2014, 160,182 common units were tendered by our employees for tax withholding purposes. These units, costing approximately $0.4 million, were returned to their respective plan and are available for future grants.

2013 Equity

At December 31, 2013, we had 1,615,017 Class A units and 28,462,185 Class B common units outstanding, which included 43,776 unvested restricted common units issued under our L-TIP Plan and 336,551 unvested restricted common units issued under our Omnibus Plan.

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At December 31, 2013, we had granted 346,734 common units of the 450,000 common units available under our L-TIP Plan. Of these grants, 302,958 have vested.

At December 31, 2013, we had granted 1,366,666 common units of the 1,650,000 common units available under our Omnibus Plan. Of these grants, 1,030,115 have vested.

For the twelve months ended December 31, 2013, 139,810 common units were tendered by our employees for tax withholding purposes. These units, costing approximately $0.2 million, were returned to their respective plan and are available for future grants.

14. SUBSEQUENT EVENTS

The following event occurred subsequent to the date of the balance sheet and prior to the filing of this Quarterly Report on Form 10-Q that could have a material impact on our consolidated financial statements or results of operations:

As of October 31, 2014, we have reached an agreement with our lenders to forego the required semi-annual redetermination process for our reserve-based credit facility until the end of the current year.

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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. We are focused on the acquisition, development and production of oil and natural gas properties and other integrated assets. Our proved reserves are currently located in the Cherokee Basin in Oklahoma, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas and in Texas and Louisiana. Our primary business objective is to create long-term value and to generate stable cash flows allowing us to invest in our business to grow our reserves and production. 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 in the Mid-Continent region and in Texas and Louisiana;
- 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.

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 SPP.

Unless the context requires otherwise, any reference in this Quarterly Report on Form 10-Q to Sanchez Production Partners, we, our, us, SPP, or the Company means Sanchez Production Partners LLC (formerly Constellation E Partners) and its subsidiaries. References in this Quarterly Report on Form 10-Q to SOG and SEP I are to Sanchez Oil & Gas Corporation and its subsidiary, Sanchez Energy Partners I, LP, respectively.

How We Evaluate our Operations

Non-GAAP Financial Measure Adjusted EBITDA

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

- interest (income) expense, net which includes:
  - interest expense

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

depreciation, depletion and amortization;

asset impairments;

accretion expense;

(gain) loss on sale of assets;

unit-based compensation programs;

gain on mark-to-market activities;

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- loss on mark-to-market activities; and
- loss on discontinued operations.

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 any 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, our lenders 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 U.S. 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 U.S. 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 U.S. GAAP performance measure, for each of the periods presented (in thousands):

	For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**	
	2014	**2013**	**2014**	**2013**
Net income (loss)	$ 5,655	$ (3,257)	$ (2,295)	$ (15,477)
Adjusted by:				
Interest expense, net	511	420	1,569	2,636
Depreciation, depletion and amortization	4,836	5,491	13,206	15,056
Asset impairments	43		237	

Accretion expense	151	163	451	409
(Gain)/loss on sale of assets		31	(23)	8
Unit-based compensation programs	86	219	1,216	828
Gain on mark-to-market activities	(5,617)	(358)	(1,183)	(1,394)
Loss on mark-to-market activities	23	4,703	6,501	12,678
Loss on discontinued operations				2,686
Adjusted EBITDA	$ 5,688	$ 7,412	$ 19,679	$ 17,430

Our Adjusted EBITDA from our continuing operations was $5.7 million for the three months ended September 30, 2014, which is lower than our Adjusted EBITDA of $7.4 million in the same period in 2013. The decrease is the result of a higher gain in mark-to-market activities, partially offset by increased oil and natural gas production from the Texas and Louisiana acquired properties.

Our Adjusted EBITDA was $19.7 million for the nine months ended September 30, 2014, higher than our Adjusted EBITDA of $17.4 million in the same period in 2013. The increase is the result of increased oil and natural gas production due to the Texas and Louisiana acquired properties and higher natural gas prices during 2014. The Texas and Louisiana properties were acquired during the third quarter of 2013 resulting in nine months of production being included in the 2014 results, compared to two months being included in the 2013 results.

During 2014, we intend to continue focusing our efforts on developing oil opportunities on our existing properties in the Mid-Continent region, Texas and Louisiana while pursuing opportunities to acquire additional properties in our operating area or merger and acquisition opportunities. Our forecasted capital spending for 2014 of $20 million to $22 million is unchanged as we continue to pursue opportunities through the end of the year. We anticipate managing our business to operate within the cash flows that are generated by our existing asset base.

Significant Operational Factors

Realized Prices. Our average realized prices for the nine months ended September 30, 2014, were $5.48 per Mcfe for natural gas and $97.01 per barrel for oil, including hedge settlements and $4.48 per Mcf for natural gas and $101.19 per barrel for oil, excluding hedge settlements. After deducting the cost of sales associated with our third party gathering, our average realized prices were $5.24 per Mcf for natural gas and $91.47 per barrel for oil, including hedge settlements and $4.24 per Mcf for natural gas and $95.65 per barrel for oil, excluding hedge settlements.

Production. Our production for the nine months ended September 30, 2014, was 6.8 Bcfe, or an average of 24,943 Mcfe per day, compared with approximately 5.9 Bcfe, or an average of 21,502 Mcfe per day, for the nine months ended September 30, 2013. Our oil and liquid production increased 86.5% for the nine months ended September 30, 2014 when compared to the same period in 2013. Our 2014 production was higher than the production for the same period in 2013 because of the increase in oil, liquid and natural gas production due to the Texas and Louisiana acquired properties and higher market prices for natural gas.

Capital Expenditures and Drilling Results. During the first nine months of 2014, we spent approximately $6.4 million in cash capital expenditures, consisting of $1.4 million for the purchase of oil and natural gas properties in LaSalle Parish, Louisiana, $3.3 million in development expenditures focused on oil completions in the Cherokee Basin and $1.7 million in development expenditures focused on properties in Texas and Louisiana. We completed eight net wells and six net recompletions during the nine months ended September 30, 2014 and had no net well recompletions in progress at September 30, 2014. During the first nine months of 2014, our daily average net oil and liquids production increased to 1,052 barrels from our average daily net production of 564 barrels for the same period during 2013.

Hedging Activities. All of our commodity derivatives are accounted for as mark-to-market activities. For the nine months ended September 30, 2014, the non-cash mark-to-market loss for our commodity derivatives was approximately $5.3 million, compared to a non-cash mark-to-market loss of $11.3 million for the same period in 2013.

Debt Reduction. We reduced our outstanding debt from a high of $220.0 million in 2009 to $52.0 million as of September 30, 2014. At September 30, 2014, we had $52.0 million in outstanding debt and $18.0 million in unused borrowing capacity under our reserve-based credit facility.

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Results of Operations

The following table sets forth the selected financial and operating data for the periods indicated (dollars in thousands):

	For the Three Months Ended September 30,		Variance		For the Nine Months Ended September 30,		Variance	
	2014	2013	$	%	2014	2013	$	%
Revenues:								
Natural gas sales at market price	$ 5,590	$ 5,384	$ 206	3.8%	$ 20,359	$ 15,003	$ 5,356	35.7%
Natural gas hedge settlements	2,485	4,174	(1,689)	-40.5%	5,088	11,448	(6,360)	-55.6%
Natural gas mark-to-market activities	282	(2,995)	3,277	109.4%	(6,124)	(10,124)	4,000	39.5%
Natural gas total	8,357	6,563	1,794	27.3%	19,323	16,327	2,996	18.3%
Oil sales	6,498	6,265	233	3.7%	21,882	14,385	7,497	52.1%
Oil hedge settlements	(408)	(235)	(173)	-73.6%	(904)	272	(1,176)	-432.4%
Oil mark-to-market activities	5,312	(1,350)	6,662	493.5%	806	(1,160)	1,966	169.5%
Oil total	11,402	4,680	6,722	143.6%	21,784	13,497	8,287	61.4%
Liquids sales	841	123	718	583.7%	1,690	377	1,313	348.3%
Miscellaneous income	796	765	31	4.1%	2,429	2,418	11	0.5%
Total revenues	21,396	12,131	9,265	76.4%	45,226	32,619	12,607	38.6%
Operating expenses:								
Lease operating expenses	5,296	5,191	105	2.0%	15,598	13,332	2,266	17.0%
Cost of sales	404	323	81	25.1%	1,198	1,122	76	6.8%
Production taxes	796	731	65	8.9%	2,563	1,840	723	39.3%
General and administrative	3,780	3,015	765	25.4%	12,942	11,156	1,786	16.0%
Gain on sale of assets		31	(31)	-100.0%	(23)	8	(31)	-387.5%
Depreciation, depletion and amortization	4,836	5,491	(655)	-11.9%	13,206	15,056	(1,850)	-12.3%
Asset impairments	43		43	100.0%	237		237	100.0%
Accretion expenses	151	163	(12)	-7.4%	451	409	42	10.3%
Total operating expenses	15,306	14,945	361	2.4%	46,172	42,923	3,249	7.6%
Other expenses (income):								
Interest expense	511	420	91	21.7%	1,569	6,284	(4,715)	-75.0%
Interest income gain from mark-to-market				0.0%		(3,648)	3,648	100.0%
Other income	(76)	23	(99)	430.4%	(220)	(149)	(71)	47.7%

Total other expenses	435	443	(8)	-1.8%	1,349	2,487	(1,138)	-45.8%
Total expenses	15,741	15,388	353	2.3%	47,521	45,410	2,111	4.6%
Loss on discontinued operations				0.0%		(2,686)	2,686	100.0%
Net income (loss)	$ 5,655	$ (3,257)	$ 8,912	273.6%	$ (2,295)	$ (15,477)	$ 13,182	85.2%

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	For the Three Months Ended September 30, 2014	2013	Variance $	%	For the Nine Months Ended September 30, 2014	2013	Variance $	%
Net production:								
Natural gas production (MMcf)	1,671	1,630	41	2.5%	5,087	4,946	141	2.9%
Oil production (MBbl)	62	63	(1)	-1.6%	216	154	62	40.3%
Liquids production (MBbl)	39		39	100.0%	71		71	100.0%
Total production (MMcfe)	**2,279**	**2,011**	**268**	**13.3%**	**6,809**	**5,870**	**939**	**16.0%**
Average daily production (Mcfe/d)	24,775	21,853	2,922	13.4%	24,943	21,502	3,441	16.0%
Total production (MBOE)	**380**	**335**	**45**	**13.4%**	**1,135**	**978**	**157**	**16.1%**
Average daily production (BOE/d)	4,129	3,642	487	13.4%	4,157	3,583	574	16.0%
Average sales prices:								
Natural gas price per Mcf with hedge	$ 5.31	$ 6.33	$ (1.02)	-16.2%	$ 5.48	$ 5.84	$ (0.36)	-6.2%
Natural gas price per Mcf without hedge	$ 3.82	$ 3.77	$ 0.05	1.3%	$ 4.48	$ 3.52	$ 0.96	27.4%
Oil price per Bbl with hedge settlements	$ 98.06	$ 95.11	$ 2.95	3.1%	$ 97.01	$ 95.24	$ 1.77	1.9%
Oil price per Bbl without hedge settlements	$ 104.63	$ 98.82	$ 5.82	5.9%	$ 101.19	$ 93.47	$ 7.72	8.3%
Total price per Mcfe with hedge settlements	$ 6.93	$ 8.19	$ (1.26)	-15.4%	$ 7.42	$ 7.48	$ (0.06)	-0.8%
Total price per Mcfe without hedge	$ 6.02	$ 6.24	$ (0.22)	-3.5%	$ 6.81	$ 5.48	$ 1.33	24.3%
Total price per BOE with hedge settlements	$ 41.60	$ 49.18	$ (7.58)	-15.4%	$ 44.54	$ 44.88	$ (0.34)	-0.8%
Total price per BOE without hedge	$ 36.13	$ 37.42	$ (1.29)	-3.4%	$ 40.85	$ 32.90	$ 7.95	24.2%
Average unit costs per Mcfe:								
Field operating expenses(a)	$ 2.67	$ 2.95	$ (0.28)	-9.6%	$ 2.67	$ 2.58	$ 0.09	3.6%
Lease operating expenses	$ 2.32	$ 2.58	$ (0.26)	-10.1%	$ 2.29	$ 2.27	$ 0.02	0.9%
Production taxes	$ 0.35	$ 0.36	$ (0.01)	-2.8%	$ 0.38	$ 0.31	$ 0.07	22.6%
General and administrative	$ 1.66	$ 1.50	$ 0.16	10.7%	$ 1.90	$ 1.90	$ 0.00	0.0%
General and administrative w/o unit-based	$ 1.62	$ 1.39	$ 0.23	16.5%	$ 1.72	$ 1.76	$ (0.04)	-2.3%
Depreciation, depletion and amortization	$ 2.12	$ 2.73	$ (0.61)	-22.3%	$ 1.94	$ 2.56	$ (0.62)	-24.2%
Average unit costs per BOE:								
Field operating expenses(a)	$ 16.04	$ 17.68	$ (1.64)	-9.3%	$ 16.00	$ 15.51	$ 0.49	3.2%
Lease operating expenses	$ 13.94	$ 15.49	$ (1.55)	-10.0%	$ 13.74	$ 13.63	$ 0.11	0.8%
Production taxes	$ 2.10	$ 2.18	$ (0.08)	-3.7%	$ 2.26	$ 1.88	$ 0.38	20.1%
General and administrative	$ 9.95	$ 9.00	$ 0.95	10.6%	$ 11.40	$ 11.41	$ (0.01)	-0.1%
General and administrative w/o unit-based	$ 9.72	$ 8.35	$ 1.37	16.4%	$ 10.33	$ 10.56	$ (0.23)	-2.2%
	$ 12.73	$ 16.39	$ (3.66)	-22.3%	$ 11.64	$ 15.39	$ (3.75)	-24.3%

Depreciation, depletion and amortization	

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

Three months ended September 30, 2014 compared to three months ended September 30, 2013

Oil, liquids and natural gas sales. Unhedged oil sales increased $0.2 million, or 3.7%, to $6.5 million for the three months ended September 30, 2014, compared to $6.3 million for the same period in 2013. Liquids sales increased $0.7 million, or 583.7%, to $0.8 million for the three months ended September 30, 2014, compared to $0.1 million for the same period in 2013. Unhedged natural gas sales increased $0.2 million, or 3.8%, to $5.6 million for the three months ended September 30, 2014, compared to $5.4 million for the same period in 2013. With hedges and mark-to-market activities, our total revenue increased $9.3 million, compared to the same period in 2013. This increase was the result of $9.9 million in higher mark-to-market activities and $1.7 million from increased sales volume, partially offset by lower cash hedge settlements from our hedge program of $1.8 million and $0.5 million attributable to lower market prices for our natural gas. Production for the three months ended September 30, 2014 was 2.3 Bcfe, which was 0.3 Bcfe higher than the same period in 2013. We hedged all of our production volumes sold through September 30, 2014, and the same through September 30, 2013. Oil and liquids production increased approximately 60.3% during the three months ended September 30, 2014, compared to the three months ended September 30, 2013, primarily as a result of our acquisition and development of properties located in Texas and Louisiana. The Texas and Louisiana properties were acquired during the third quarter of 2013 resulting in production for only a partial quarter being reflected during the quarter ended September 30, 2013, compared to a full quarter of production being reflected during the quarter ended September 30, 2014.

Cash hedge settlements received for our commodity derivatives were approximately $2.1 million for the three months ended September 30, 2014, compared to cash hedge settlements received of approximately $3.9 million for the three months ended September 30, 2013. This difference was due to changes in hedge prices, hedged volumes and market prices for natural gas and oil during 2013 and 2014.

As discussed below, our non-cash mark-to-market activities increased by $9.9 million for the three months ended September 30, 2014, compared to the same period in 2013. Our realized prices before our hedging program decreased from 2013 to 2014 for both our natural gas production and oil production. These realized prices were impacted 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 September 30, 2014, the non-cash mark-to-market gain was approximately $5.6 million, compared to a non-cash mark-to-market loss of $4.3 million for the same period in 2013. The 2014 non-cash gain was the result of the impact of lower future expected oil and natural gas prices on these derivative transactions that were being accounted for as mark-to-market activities, while non-performance risk was not a factor. The 2013 non-cash loss represented approximately $4.3 million from the impact of higher future expected oil and natural gas prices on these derivative transactions that were being accounted for as mark-to-market activities, while non-performance risk was not a factor.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

For the three months ended September 30, 2014, lease operating expenses increased $0.1 million, or 2.0%, to $5.3 million, compared to expenses of $5.2 million for the same period in 2013. This increase in lease operating expenses was related to an increase of $0.3 million in non-operated lease operating expenses resulting from the Texas and Louisiana properties that were acquired during the third quarter of 2013 and $0.1 million in higher labor and benefits expenses, partially offset by $0.3 million in lower insurance costs.

For the three months ended September 30, 2014, per unit lease operating expenses were $2.32 per Mcfe compared to $2.58 per Mcfe for the same period in 2013. This decrease is due to increased production volumes during 2014.

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 increased $0.8 million, or 25.4%, to $3.8 million for the three months ended September 30, 2014, compared to $3.0 million for the same period in 2013. Our general and administrative expenses were higher in 2014 due to $0.4 million in higher labor and incentive compensation costs and $0.5 million in higher legal and professional services, partially offset by $0.1 million in lower unit-based compensation.

Our per unit costs were $1.66 per Mcfe for the three months ended September 30, 2014, compared to $1.50 per Mcfe for the same period in 2013.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense includes the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming everything else remains unchanged, as oil or natural gas production changes, depletion changes in the same direction.

Our depreciation, depletion and amortization expense for the three months ended September 30, 2014 was $4.8 million, or $2.12 per Mcfe, compared to $5.5 million, or $2.73 per Mcfe, for the same period in 2013. This decrease is the result of production volumes. Our other assets are depreciated using the straight-line basis. Consistent with our prior practice, we are using our 2013 reserve report to calculate our depletion rate during the first three quarters of 2014 and will use our 2014 reserve report to record our depletion in the fourth quarter of 2014.

Interest expense. Interest expense for the three months ended September 30, 2014 increased $0.1 million, or 21.7%, to $0.5 million, compared to $0.4 million for the same period in 2013. This increase was due to debt costs which were incurred in May 2014 with the increase in the borrowing base. The average interest rate on our outstanding debt was approximately 3.154% at September 30, 2014, compared to 3.68% at September 30, 2013.

Nine months ended September 30, 2014 compared to nine months ended September 30, 2013

Oil, liquids and natural gas sales. Unhedged oil sales increased $7.5 million, or 52.1%, to $21.9 million for the nine months ended September 30, 2014, compared to $14.4 million for the same period in 2013. Liquids sales increased $1.3 million, or 348.3%, to $1.7 million for the nine months ended September 30, 2014, compared to $0.4 million for the same period in 2013. Unhedged natural gas sales increased $5.4 million, or 35.7%, to $20.4 million for the nine months ended September 30, 2014, compared to $15.0 million for the same period in 2013. With hedges and mark-to-market activities, our total revenue increased $12.6 million when compared to the same period in 2013. This increase was the result of $9.0 million due to higher market prices for our natural gas and oil production, $6.0 million in higher mark-to-market activities and $5.1 million in higher production volume, partially offset by $7.5 million in lower cash hedge settlements from our derivatives program. Production for the nine months ended September 30, 2014 was 6.8 Bcfe, which was 0.9 Bcfe higher than the same period in 2013. We hedged all of our production volumes sold through September 30, 2014, and the same through September 30, 2013. Oil and liquids production increased approximately 86.4% during the nine months ended September 30, 2014, compared to the nine months ended September 30, 2013, as a result of our acquisition and development of properties located in Texas and Louisiana.

Cash hedge settlements received for our commodity derivatives were approximately $4.2 million for the nine months ended September 30, 2014, compared to cash hedge settlements received of $11.7 million for the nine months ended September 30, 2013. This difference was due to changes in hedge prices, hedged volumes and market prices for natural gas and oil during 2013 and 2014.

As discussed below, our non-cash mark-to-market activities increased by $6.0 million for the nine months ended September 30, 2014, compared to the same period in 2013. Our realized prices before our hedging program increased from 2013 to 2014 for both our natural gas production and oil production. These realized prices were impacted 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 nine months ended September 30, 2014, the non-cash mark-to-market loss was approximately $5.3 million, compared to a non-cash mark-to-market loss of $11.3 million for the same period in 2013. The 2014 non-cash loss was the result of the impact of higher future expected oil and natural gas prices on these derivative transactions that were being accounted for as mark-to-market activities, while non-performance risk was not a factor. The 2013 non-cash loss represented approximately $11.3 million from the impact of higher future expected oil and natural gas prices on these derivative transactions that are being accounted for as mark-to-market activities while non-performance risk associated with our counterparties was not a factor.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

For the nine months ended September 30, 2014, lease operating expenses increased $2.3 million, or 17.0%, to $15.6 million, compared to expenses of $13.3 million for the same period in 2013. This increase in lease operating expenses was primarily related to $1.5 million in non-operated lease operating expenses resulting from the Texas and Louisiana properties that were acquired during the third quarter of 2013, $0.5 million in higher labor and benefits expenses and $0.3 million in higher parts and supplies and oil and gas treating costs.

For the nine months ended September 30, 2014, per unit lease operating expenses were $2.29 per Mcfe compared to $2.27 per Mcfe for the same period in 2013.

For the nine months ended September 30, 2014, production taxes increased $0.7 million, or 39.3%, to $2.5 million, compared to expenses of $1.8 million for the same period in 2013. This increase was primarily the result of increased oil and natural gas production and higher market prices for oil and natural gas in 2014.

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 increased $1.8 million, or 16.0%, to $13.0 million for the nine months ended September 30, 2014, compared to $11.2 million for the same period in 2013. Our general and administrative expenses were higher in 2014 due to $1.0 million in higher legal and professional services costs, a management fee paid to SOG in conjunction with the Services Agreement of $1.0 million, $0.4 million in higher unit-based compensation and $0.2 million in higher labor and incentive compensation costs, partially offset by $0.8 million in lower severance costs.

Our per unit costs were $1.90 per Mcfe for the nine months ended September 30, 2014, compared to $1.90 per Mcfe for the same period in 2013.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense includes the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming everything else remains unchanged, as oil or natural gas production changes, depletion changes in the same direction.

Our depreciation, depletion and amortization expense for the nine months ended September 30, 2014 was $13.2 million, or $1.94 per Mcfe, compared to $15.1 million, or $2.56 per Mcfe, for the same period in 2013. This decrease is the result of production volumes. Our other assets are depreciated using the straight-line basis. Consistent with our prior practice, we are using our 2013 reserve report to calculate our depletion rate during the first three quarters of 2014 and will use our 2014 reserve report to record our depletion in the fourth quarter of 2014.

For the nine months ended September 30, 2014, our non-cash impairment charges were approximately $0.2 million to impair the value of our oil and natural gas fields in Texas and Louisiana based on changes in reserve estimates. For the nine months ended September 30, 2013, we did not have an impairment to record.

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Interest expense. Interest expense for the nine months ended September 30, 2014 decreased $1.1 million, or 40.5%, to $1.5 million, compared to $2.6 million for the same period in 2013. This decrease was due to a lower average debt outstanding balance during the first nine months of 2014 compared to the first nine months of 2013, along with a lower average interest rate. The average interest rate on our outstanding debt was approximately 3.154% at September 30, 2014 compared to 3.68% at September 30, 2013.

Liquidity and Capital Resources

During the first nine months of 2014, we utilized our cash flow from operations as our primary source of capital to fund our operating and capital programs. Our primary use of capital during this time was for development of existing oil opportunities within our existing asset base in the Mid-Continent and Gulf Coast regions.

Based upon our current business plan for 2014, we anticipate that we will continue to generate sufficient operating cash flow to meet our working capital needs and fund a planned capital expenditure program between $20.0 million and $22.0 million. We will be monitoring the capital resources available to us to meet our future financial obligations and our remaining planned 2014 capital expenditures. Our current expectation is that we will continue managing our business to operate within the cash flows that are generated. Our quarterly distributions to our unitholders remained suspended through the third quarter of 2014. 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.

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 position and expected production levels in 2014, we anticipate that our cash flow from operations can meet our planned capital expenditures and other cash requirements for the next twelve months without increasing our debt. If needed, we may issue additional equity securities to raise additional capital. Future cash flows and our borrowing capacity are subject to a number of variables, including oil and natural gas production, the market prices for those products and our hedge position. 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.

Sources of Debt and Equity Financing

As of September 30, 2014, the borrowing base under our reserve-based credit facility was $70.0 million and we had $52.0 million of debt outstanding under the facility, leaving us with $18.0 million in unused borrowing capacity. Our reserve-based credit facility matures on May 30, 2017.

Cash Flow from Operations

Our net cash flow provided by operating activities for the nine months ended September 30, 2014 was $12.7 million, compared to $9.8 million for the same period in 2013.

Our cash flow from operations is subject to many variables, the most significant of which are the volatility of market prices for oil and natural gas, our hedging program and our level of production of oil and natural gas. Our future cash flow from operations will depend on our ability to maintain and increase production through our development program, acquisitions and successful execution of our hedging program. For additional information on our business plan, refer to Outlook .

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Open Commodity Hedge Position

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. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to fund higher severance taxes, which are usually based on market prices for oil and natural gas. Our operating cash flows are also impacted by the cost of oilfield services. In the event of inflation increasing service costs or administrative expenses, our hedging program will limit our ability to have increased operating cash flows to fund these higher costs. Increases in the market prices for oil and natural gas will also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. All of our derivatives are with Societe Generale, a lender in our reserve-based credit facility, and The Bank of Nova Scotia. 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. 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.

Investing Activities Acquisitions and Capital Expenditures

Cash used by investing activities was $6.1 million for the nine months ended September 30, 2014, compared to cash provided by investing activities of $26.3 million for the same period in 2013. Our cash capital expenditures were $6.4 million, consisting of $1.4 million for the purchase of oil and natural gas properties in LaSalle Parish, Louisiana, $3.3 million in development expenditures focused on oil completions in the Cherokee Basin and $1.7 million in development expenditures focused on properties in Texas and Louisiana. We completed eight net wells and six net recompletions during the nine months ended September 30, 2014 and had no net well and net recompletions in progress at September 30, 2014.

Our cash capital expenditures were $32.8 million for the nine months ended September 30, 2013, which consisted of $12.1 million in development expenditures focused on oil completions in the Cherokee Basin and $0.1 million to acquire certain additional natural gas wells in the Cherokee Basin, $20.1 million to acquire SEP I wells and $0.5 million in development expenditures focused on SEP I properties. We completed 46 net wells and 13 net recompletions during the first nine months of 2013 and had 20 net wells and net recompletions in progress at September 30, 2013. We also sold our Robinson s Bend Field assets in the Black Warrior Basin of Alabama for net proceeds of approximately $59.0 million after customary costs and working capital adjustments and received $0.1 million in distributions from an equity affiliate.

Financing Activities

Net cash used in financing activities was $1.8 million for the nine months ended September 30, 2014, compared to $34.4 million for the same period in 2013. During the nine months ended September 30, 2014, we had borrowings under our reserve-based credit facility of $5.8 million for working capital purposes and repayments of $4.5 million. We used $1.65 million to purchase the Class C and Class D interests from Constellation Energy Partners Holdings, LLC, as part of the Exelon Litigation settlement. We used $0.8 million for the payment of the PostRock Litigation settlement of $6.5 million, which had been accrued at December 30, 2013, but was not paid until the second quarter of 2014. We used $0.4 million during the nine months ended September 30, 2014 to fund the cost of units tendered by employees for tax withholdings for unit-based compensation.

Our net cash used by financing activities was $34.4 million for the nine months ended September 30, 2013. During the first nine months of 2013, we used $50.2 million of cash to reduce our outstanding debt. This debt reduction was funded by the proceeds from the sale of our Robinson s Bend Field assets in the Black Warrior Basin of Alabama. We also used $0.2 million to fund the cost of units tendered by employees for tax withholdings for unit-based compensation.

Off-Balance Sheet Arrangements

As of September 30, 2014, we had no off-balance sheet arrangements with third parties, and we maintained no debt obligations that contained 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 September 30, 2014, we have not suffered any significant losses with our counterparties as a result of non-performance.

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 guarantees from Macquarie Bank Limited for up to $2.0 million in purchases through December 31, 2015, and up to $2.0 million in purchases through January 31, 2016. As of September 30, 2014, we had no past due receivables from Macquarie.

Scissortail Energy, LLC

Scissortail Energy, LLC (Scissortail), a subsidiary of Kinder Morgan Energy Partners, L.P., purchases a portion of our natural gas production in Oklahoma and Kansas. As of September 30, 2014, we have no past due receivables from Scissortail.

Derivative Counterparties

As of September 30, 2014, all of our derivatives are with Societe Generale, a lender in our reserve-based credit facility, and The Bank of Nova Scotia. 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 September 30, 2014, each of these financial institutions had an investment grade credit rating.

Reserve-Based Credit Facility

As of September 30, 2014, the banks and their percentage commitments in our reserve-based credit facility are: Societe Generale (36.36%), OneWest Bank, FSB (36.36%), and BOKF NA, dba Bank of Oklahoma (27.28%). As of September 30, 2014, each of these financial institutions has an investment grade credit rating.

Outlook

During 2014, 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, 2013, as well as the

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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 2014 Expected Results

Our 2014 business plan and forecast is focused on prioritizing oil production in the execution of our capital program, actively managing our operating expenses and actively pursuing merger and acquisition opportunities that could lead to enhanced unitholder value. We currently expect our operating environment to be characterized by continued low natural gas prices, stable oil prices and the pressure to reduce operating expenses.

For 2014, we currently anticipate:

- Our production to be in a range of 8.1 Bcfe to 9.3 Bcfe, approximately 93% of which is currently hedged.

- Our operating expenses to be actively managed, resulting in a range of $33.3 million to $37.3 million.

- Our Adjusted EBITDA to be in a range of $26.7 million to $29.9 million.

- Our total capital expenditures to be between $20.0 million to $22.0 million. Our entire capital budget for 2014 will be focused on capital efficient oil drilling and recompletion opportunities in our existing properties.

- At the present time, we are actively pursuing merger and acquisition opportunities that could lead to enhanced unitholder value.

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. The results of these estimates and assumptions form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of our financial statements.

As of September 30, 2014, 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, 2013, which was filed with the SEC on March 27, 2014. The policies disclosed included the accounting for oil and natural gas properties, oil and natural gas reserve quantities, 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

See Note 1 to our condensed consolidated financial statements included in this report for information on new accounting pronouncements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

This section is not applicable to smaller reporting companies.

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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 SPP 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 SPP 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 September 30, 2014 (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

In January 2013, we terminated our support services agreement with Schlumberger, ePrime Services. Through this outsource agreement, Schlumberger managed the payable and receivable activities associated with our interests in oil and natural gas properties, including the payment of invoices, calculation and payment of royalties, and receipt of revenues from oil and natural gas sales, and provided accounting information used to generate financial statements. These functions are now handled by our internal accounting department in Houston, Texas, utilizing the same oil and natural gas computer software Schlumberger used. Additional experienced staffing has been hired, primarily in the revenue accounting and accounts payable functions.

During the nine months ended September 30, 2014, there were no changes in SPP 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, SPP s internal control over financial reporting.

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Part II Other Information

Item 1. Legal Proceedings

On August 30, 2013, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPM, Gary M. Pittman and John R. Collins against the Company, certain of its officers and managers, SOG and SEP I (the PostRock Litigation) in connection with the Company s closing on August 9, 2013 of the purchase of oil and natural gas properties from SEP I and the issuance of units in connection therewith. The plaintiffs contended, among other things, that the issuance of the units to SEP I in connection with the acquisition was not permitted under the Company s operating agreement, that Messrs. Pittman and Collins should not have been removed as the Class A managers of the Company s board of managers, and that SEP I, SOG and our current Class A managers participated in bad faith conduct of the other defendants and interfered with CEPM s contractual rights under the Company s operating agreement. The plaintiffs alleged claims against the Company and certain of its managers and officers relating to breach of contract, breach of the duty of good faith, and breach of the implied covenant of good faith and fair dealing; the plaintiffs also alleged aiding and abetting and tortuous interference claims against SOG, SEP I and our current Class A managers. The plaintiffs sought, among other things, declaratory relief reappointing Messrs. Pittman and Collins to the Company s board of managers and removing our current Class A managers therefrom, and an injunction against the Company taking any further action outside the ordinary course of business during the pendency of the litigation, declaratory relief rescinding the units issued by the Company to SEP I, declaratory relief that CEPM had sole voting power with respect to the outstanding Class A units, declaratory relief that the Company s officers and managers breached fiduciary and contractual duties and were not entitled to indemnification from the Company as a result thereof, and monetary damages. On March 31, 2014, the parties to the lawsuit reached a settlement agreement and the lawsuit was subsequently dismissed. As a result of the settlement, the Class A units acquired by SEP I in the August 2013 transaction were returned to SPP and cancelled in exchange for $0.8 million; CEPM transferred 100% of its Class A units and 414,938 of SPP s Class B units to SEP I in exchange for an aggregate payment of $1.0 million from SEP I, and SPP paid $6.5 million to CEPM. In addition, pursuant to the terms of the settlement, CEPM agreed to sell its remaining Class B units over the next nine months, with SEP I providing up to a $5.0 million backstop payment to CEPM to the extent proceeds received by CEPM from such sale do not meet or exceed a specified amount. As a result of the settlement, the settling parties filed a stipulation in the Court of Chancery of the State of Delaware seeking to lift the preliminary injunction issued on December 3, 2013, and the litigation was dismissed with prejudice. The settlement also included mutual releases between the plaintiffs and defendants. In connection with the settlement, we received $1.25 million on April 10, 2014, under our directors and officers insurance policy.

On February 28, 2014, a lawsuit was filed in the Chancery Court of the State of Delaware by CEPH against the Company (the Exelon Litigation) seeking repayment of suspended distributions in relation to the Class D Interests held by CEPH. In 2006, Constellation Holding, Inc (CHI), which merged with and into CEPH in December 2012, purchased the Company s Class D Interests for $8.0 million. The $8.0 million was to be repaid to CEPH in quarterly distributions of $333,333.33 over a period of six years; however, these distributions could be temporarily suspended if a dispute arose over pricing formulas related to the sale of natural gas from the Robinson s Bend properties. A dispute arose, so the distributions were suspended pursuant to the Company s operating agreement and never reinstated. CEPH contended, among other things, that the Company breached its contract to pay the quarterly distributions, acted in bad faith and received unjust enrichment by suspending the quarterly distributions. On June 26, 2014, the parties to the lawsuit reached a settlement agreement and the lawsuit was subsequently dismissed. In conjunction with the settlement, we paid CEPH $1.65 million in exchange for all of the Class C management incentive interests and the Class D interests held by CEPH, which accounted for all of such interests issued by SPP. Effective with the acquisition from CEPH, we cancelled the Class C management incentive interests and Class D interests.

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

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Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in Item 1A. to Part I of our Annual Report on Form 10-K for the year ended December 31, 2013 that was filed with the SEC on March 27, 2014. 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 2013 Form 10-K. These risks and uncertainties are not the only ones facing us and there may be additional matters that are not known to us or that we currently consider immaterial. All of these risks and uncertainties could adversely affect our business, financial condition or future results and, thus, the value of an investment in us.

Forward-Looking Statements

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

- business strategy;
- acquisition strategy;
- financial strategy;
- ability to resume, maintain and grow distributions;
- drilling locations;
- oil, natural gas and natural gas liquids reserves;
- realized oil, natural gas and natural gas liquids prices;
- production volumes;
- lease operating expenses, general and administrative expenses and developmental costs;
- future operating results and

plans, objectives, expectations, forecasts, outlook and intentions.

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, will, could, should, expect, plan, project, intend, anticipate, believe, e 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. The forward-looking statements speak only as of the date made, and other than as required by law, 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.

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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.

Item 6. Exhibits

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

1. Financial Statements:

Condensed Consolidated Balance Sheets Sanchez Production Partners LLC at September 30, 2014 and December 31, 2013

Condensed Consolidated Statements of Operations and Comprehensive Income/(Loss) Sanchez Production Partners LLC for the nine months ended September 30, 2014 and September 30, 2013

Condensed Consolidated Statements of Cash Flows Sanchez Production Partners LLC for the nine months ended September 30, 2014 and September 30, 2013

Condensed Consolidated Statements of Changes in Members Equity Sanchez Production Partners LLC for the nine months ended September 30, 2014

Notes to Condensed Consolidated Financial Statements

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EXHIBIT INDEX

Exhibit Number	Description
*31.1	Certification of Chief Executive Officer, Chief Operating Officer, and President of Sanchez Production Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Principal Financial Officer and Principal Accounting Officer of Sanchez Production 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 Sanchez Production 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 Principal Financial Officer and Principal Accounting Officer of Sanchez Production 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

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SIGNATURES

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

SANCHEZ PRODUCTION PARTNERS LLC

(REGISTRANT)

Date: November 13, 2014	By	/S/ CHARLES C. WARD
		Charles C. Ward
		Chief Financial Officer and Treasurer

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ANNEX F

SANCHEZ ENTITY INFORMATION

This Annex F contains certain information about SOG, SP Holdings, SEPI and their affiliates and controlling persons.

SOG

SOG is in the business of managing oil and natural gas properties on behalf of its affiliates. The executive officers and directors of SOG are set forth below, along with their principal occupations and other material occupations, positions, offices and employment during the past five years. SOG is a Delaware corporation. Each of SOG and the entities and natural persons listed below has a business address of 1000 Main St., Suite 3000, Houston, Texas 77002 unless otherwise noted.

Name	*Principal Occupation at SOG*	*Other Material Positions*
Antonio R. Sanchez, Jr.	Chief Executive Officer & Director (10/1982-present); Chairman of the Board (7/1992-present)	Sanchez Energy Corp., an oil and gas exploration and production company; Executive Chairman of the Board (11/2012-present)
		International Bank of Commerce, a state chartered bank; Director (5/1995-present)(1)
Antonio R. Sanchez, III	Co-President (7/2014-present); President (3/2006-7/2014)	Sanchez Energy Corp., an oil and gas exploration and production company; President and Chief Executive Officer (8/2011-present)
		Zix Corporation, a technology company; Director (5/2003-6/2014)(2)
		Sanchez Production Partners LLC, an oil and gas exploration and production company; Manager (8/2013-present)

		SP Capital Holdings, LLC, the holding company for SP Holdings; Managing Member (3/2014-present)
		SEP Management I, LLC, the general partner of SEPI, President & Chief Executive Officer (7/2014-present); President (8/2007-7/2014)
Eduardo A. Sanchez	Co-President (7/2014-present); Executive Vice President (1/2013-7/2014)	Sanchez Resources, LLC, a manager of oil and gas properties; Manager (10/2010-8/2013); President & Chief Executive Officer (8/2013-present)
		SP Capital Holdings, LLC, the holding company for SP Holdings; Managing Member (3/2014-present)

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Name	*Principal Occupation at SOG*	*Other Material Positions*
Patricio D. Sanchez	Co-President (7/2014-present); Executive Vice President (4/2010-7/2014)	Santerra Holdings, LLC, an oil and gas exploration and production company; Managing Member (2/2012-present)
Ana Lee Sanchez Jacobs	Executive Vice President (7/2014-present)	None
Frank A. Guerra	Executive Vice President (3/2009-present); Executive Vice President Chief Financial Officer (3/2006-3/2009); President & Chief Financial Officer (5/1998-2/2006); Vice President (5/1984-5/1998)	SEP Management I, LLC, the general partner of SEPI; Executive Vice President (8/2007-present)
Gerald F. Willinger	Executive Vice President (7/2014-present)	Sanchez Resources, LLC, a manager of oil and gas properties; Manager (10/2010-8/2013); Executive Vice President (7/2014-present) Sanchez Production Partners LLC, an oil and gas exploration and production company; Manager (8/2013-present) Silver Point Capital, LLC, a credit-opportunity fund, Senior Analyst (1/2006-12/2009)(3)
Michael G. Long	Executive Vice President Chief Financial Officer (4/2014-present); Senior Vice President Chief Financial Officer (3/2009-3/2014)	Sanchez Energy Corp., an oil and gas exploration and production company; Executive Vice President (1/2014-present); Chief Financial Officer and Secretary (8/2011-present); Senior Vice President (8/2011-1/2014) SEP Management I, LLC, the general partner of SEPI; Executive Vice President Chief Financial Officer

		(7/2014-present); Senior Vice President Chief Financial Officer (6/2008-7/2014)
Christopher D. Heinson	Senior Vice President Chief Operating Officer (7/2014-present); Chief Operating Officer (3/2014-7/2014); Interim Chief Operating Officer (1/2014-3/2014); Senior Reservoir Engineering Manager (3/2013-12/2013)	Sanchez Energy Corp., an oil and gas exploration and production company; Chief Operating Officer (3/2014-present)
		Occidental Petroleum Corporation, an oil and gas exploration and production company; Senior Development Planning Engineer (3/2011-3/2013); Reservoir Engineer (5/2007-3/2011)(4)

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Name	Principal Occupation at SOG	Other Material Positions
John H. Happ, III	Senior Vice President Marketing & Midstream (7/2014-present)	Geosouthern Energy Corp., an oil and gas exploration and production company; General Manager of Marketing & Midstream (4/2011-6/2014)(5)
		Nexterra Energy Resources, a wholesale generator of electricity; Regional Director of Origination (1/2011-4/2011)(6)
		Tauber Oil Company, an oil and gas marketing company; Vice President Natural Gas & Emissions (7/2008-5/2010)(7)

(1) The address is 1200 San Bernardo, Laredo, TX 78042.
(2) The address is 2711 N. Haskell Avenue, Suite 2200, Dallas, TX 75204.
(3) The address is Two Greenwich Plaza, Greenwich, CT 06830.
(4) The address is 5 Greenway Plaza, Houston, TX 77046.
(5) The address is 1425 Lake Front Circle, The Woodlands, TX 77380.
(6) The address is 1000 Louisiana St., Houston, TX 77002.
(7) The address is 55 Waugh Drive, Houston, TX 77007.

The controlling owners of SOG are Antonio R. Sanchez, Jr. and Santig, Ltd., a Texas limited liability company in the business of owning and managing family investments. The managing member of Santig, Ltd. is Sanchez Management Corporation, which is owned 100% by Antonio R. Sanchez, Jr. Antonio R. Sanchez, Jr. is Chairman and President of Sanchez Management Corporation and Antonio R. Sanchez, III is the Executive Vice President. Antonio R. Sanchez, Jr. and Antonio R. Sanchez, III have ultimate control of SOG through their individual ownership or ownership and control of Santig, Ltd. The business address of each of the foregoing is 1000 Main St., Suite 3000, Houston, Texas 77002.

SP Holdings

SP Holdings is in the business of providing fee-based management and advisory services to oil and gas companies. SP Holdings has no officers. The sole manager and member of SP Holdings is SP Capital Holdings, LLC, which has no officers. The co-managers of SP Capital Holdings, LLC are Antonio R. Sanchez, III and Eduardo A. Sanchez. Both of SP Holdings and SP Capital Holdings, LLC are Texas limited liability companies. Each of SP Holdings and SP Capital Holdings, LLC has a business address of 1000 Main St., Suite 3000, Houston, Texas 77002. SP Capital Holdings, LLC is owned by Antonio R. Sanchez, III, Eduardo A. Sanchez, Patricio D. Sanchez, Ana Lee Sanchez Jacobs and Antonio R. Sanchez, Jr. See the information in the table above under the heading SOG for biographical information regarding each of the natural persons listed in this paragraph.

SEPI

SEPI is in the business of serving as general partner for entities involved in the exploration and production of oil and gas assets. SEPI has no officers. The general partner of SEPI is SEP Management I, LLC. The executive officers of SEP Management I, LLC are Antonio R. Sanchez, III, Frank A. Guerra and Michael G. Long. SEPI is a Delaware limited partnership, and SEP Management I, LLC is a Delaware limited liability company. Each of SEPI and SEP Management I, LLC has a business address of 1000 Main St., Suite 3000, Houston, Texas 77002. SOG is the sole member of SEP Management I, LLC. See the information in the table above under the heading SOG for additional information regarding SOG and biographical information regarding each of the natural persons listed in this paragraph.

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Other Information

The business address for each of SOG, SP Holdings, SEPI, Antonio R. Sanchez, III and Gerald F. Willinger is 1000 Main St., Suite 3000, Houston, Texas 77002. The business telephone number for each of the foregoing is (713) 783-8000.

None of SOG, SP Holdings, Santig, Ltd., Sanchez Management Corporation, SP Capital Holdings, LLC, SEPI, SEP Management I, LLC or any of the natural persons listed in this Annex F has been (i) convicted in a criminal proceeding during the past five years (excluding traffic violations or similar misdemeanors) or (ii) a party to any judicial or administrative proceeding during the past five years (except for matters that were dismissed without sanction or settlement) that resulted in a judgment, decree or final order enjoining the person from future violations of, or prohibiting activities subject to, federal or state securities laws, or a finding of any violation of federal or state securities laws.

Each of the natural persons listed in this Annex F is a citizen of the United States.

SP Holdings is estimated to incur $100,000 for legal expenses in connection with the Conversion.

Certain Transactions

In December 2014, the Company issued 59,562 common units to SP Holdings pursuant to the terms of the Services Agreement in connection with SP Holdings election pursuant to the terms thereof to receive payment of the fee thereunder for the quarter ended September 30, 2014 in common units rather than cash. This issuance of common units was in lieu of paying a fee of $165,582 in cash, or $2.78 per common unit.

Subject to the terms of the Settlement Agreement previously disclosed under Special Factors Background of the Conversion and Relationship with SOG (the Settlement Agreement), CEPM was required to pursue sales of all of its common units (the Subject Units) by December 15, 2014 (or such earlier date upon which all of the Subject Units have been sold, the Determination Date). As further described below, CEPM was required to share any excess proceeds and/or Subject Units with SEPI if the aggregate amount actually received by CEPM from the sales of the Subject Units pursuant to the Settlement Agreement (the Actual Proceeds) exceeded the Subject Unit Target Proceeds (as defined below). As of December 15, 2014, CEPM sold all but 499,701 Subject Units. The Actual Proceeds from these sales were $14,745,391.84.

Under the Settlement Agreement, on the Determination Date, in the event that there was any surplus achieved from the sales of the Subject Units in excess of approximately $14.3 million (the Subject Unit Target Proceeds), or there were any Subject Units still owned by CEPM after CEPM received the Subject Units Target Proceeds, then CEPM and SEPI agreed to share equally in the excess proceeds and/or Subject Units. However, this sharing was subject to the restriction that SEPI s (including its designee s) one-half share in any aggregate proceeds in excess of the Subject Target Proceeds was to be capped at $5 million (i.e., SEPI was not entitled to share further in aggregate proceeds in excess of the Subject Unit Target Proceeds once the aggregate excess amount exceeded $10 million).

The Actual Proceeds exceeded the Subject Unit Target Proceeds by $479,261.84. On or about December 17, 2014, CEPM (i) paid $239,631 (half of the net proceeds in excess of the Subject Unit Target Proceeds) to SP Holdings for the account of SEPI and (ii) transferred 224,851 Subject Units (half of the remaining Subject Units held by CEPM) to SP Holdings for the account of SEPI.

See also Special Factors Background of the Conversion and Relationship with SOG.

As disclosed under Security Ownership of Certain Beneficial Owners and Management, Messrs. Sanchez, III and Willinger each individually own 6,403 (or less than 1.0%) of the Company s common units, which were

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received in connection with their service as members of the Company s board of managers. Mr. Guerra individually owns 6,750 (or less than 1.0%) of the Company s common units, which were acquired in the open market on November 7, 2014 (1,750 units for $2.36 per unit) and November 12, 2014 (5,000 units for $2.37 per unit).

Except for the foregoing or as described elsewhere in this proxy statement/prospectus, none of SOG, SP Holdings, Santig, Ltd., Sanchez Management Corporation, SP Capital Holdings, LLC, SEPI, SEP Management I, LLC, any subsidiary of the foregoing or any of the natural persons listed in this Annex F has, during the past two years, (i) acquired any common units of the Company or its affiliates, (ii) entered into any transaction with the Company or its affiliates, or (iii) engaged in any negotiations, transactions or material contacts with the Company or its affiliates. Except for such with the Company as described in this Annex F or elsewhere in this proxy statement/prospectus, none of SOG, SP Holdings, Santig, Ltd., SP Capital Holdings, LLC, SEPI, SEP Management I, LLC, any subsidiary of the foregoing or any of the natural persons listed in this Annex F has entered into any agreement, arrangement or understanding regarding the Company s common units.

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 20. Indemnification of Managers and Officers

Under our operating agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by law from and against all losses, claims, damages or similar events any person who is or was our manager or officer, or while serving as our manager or officer, is or was serving as a tax matters member or, at our request, as a manager, officer, tax matters member, employee, partner, fiduciary or trustee of us or any of our subsidiaries. In addition, we are required indemnify to the fullest extent permitted by law and authorized by our board of managers, from and against all losses, claims, damages or similar events, any person who is or was an employee or agent (other than an officer) of our company.

Any indemnification under our operating agreement will only be out of our assets. We are authorized to purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our operating agreement.

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Item 21. Exhibits and Financial Statement Schedules

(a) Exhibits

2.1	Plan of Conversion (included as Annex A to the proxy statement/prospectus)
4.1*	Form of Certificate of Conversion of Sanchez Production Partners LLC
4.2*	Form of Certificate of Limited Partnership of Sanchez Production Partners LP
4.3	Form of Agreement of Limited Partnership of Sanchez Production Partners LP (included as Annex B to the proxy statement/prospectus)
4.4*	Form of Certificate of Formation of Sanchez Production Partners GP LLC
4.5*	Form of Limited Liability Company Agreement of Sanchez Production Partners GP LLC
4.6*	Form of First Amended and Restated Limited Liability Company Agreement of Sanchez Production Partners GP LLC
4.7	Form of Sanchez Production Partners LP Long-Term Incentive Plan (included as Annex C to the proxy statement/prospectus)
5.1*	Opinion of Andrews Kurth LLP as to the legality of the securities
8.1*	Tax Opinion of Andrews Kurth LLP
23.1	Consent of KPMG LLP
23.2	Consent of PricewaterhouseCoopers LLP
23.3	Consent of Andrews Kurth LLP (included in opinions filed as Exhibits 5.1 and 8.1)
23.4	Consent of Netherland, Sewell & Associates, Inc.
24.1*	Powers of Attorney (included on signature page)
99.1	Form of Proxy for Holders of Sanchez Production Partners LLC Common Units
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Previously filed

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Item 22. Undertakings

(1) The undersigned Registrant hereby undertakes to file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement: (i) to include any prospectus required by Section 10(a)(3) of the Securities Act of 1933, as amended (the Securities Act); (ii) to reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement (notwithstanding the foregoing, any increase or decrease in volume of securities offered (if the total dollar value of securities offered would not exceed that which was registered) and any deviation from the low or high end of the estimated maximum offering range may be reflected in the form of prospectus filed with the Commission pursuant to Rule 424(b) if, in the aggregate, the changes in volume and price represent no more than a 20% change in the maximum aggregate offering price set forth in the Calculation of Registration Fee table in the effective registration statement); and (iii) to include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement.

(2) The undersigned Registrant hereby undertakes that, for the purpose of determining any liability under the Securities Act of 1933, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(3) The undersigned Registrant hereby undertakes to remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering.

(4) The undersigned Registrant hereby undertakes that, for purposes of determining any liability under the Securities Act of 1933, each filing of the Registrant s annual report pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 (and, where applicable, each filing of an employee benefit plan s annual report pursuant to Section 15(d) of the Securities Exchange Act of 1934) that is incorporated by reference in the registration statement will be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time will be deemed to be the initial bona fide offering thereof.

(5) The undersigned Registrant hereby undertakes as follows: that prior to any public reoffering of the securities registered hereunder through use of a proxy statement/prospectus which is a part of this registration statement, by any person or party who is deemed to be an underwriter within the meaning of Rule 145(c), the issuer undertakes that such reoffering proxy statement/prospectus will contain the information called for by the applicable registration form with respect to reofferings by persons who may be deemed underwriters, in addition to the information called for by the other Items of the applicable form.

(6) The Registrant undertakes that every prospectus (1) that is filed pursuant to the immediately preceding paragraph, or (2) that purports to meet the requirements of Section 10(a)(3) of the Securities Act and is used in connection with an offering of securities subject to Rule 415, will be filed as a part of an amendment to the registration statement and will not be used until such amendment is effective, and that, for purposes of determining any

liability under the Securities Act of 1933, each such post-effective amendment will be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time will be deemed to be the initial bona fide offering thereof.

(7) The undersigned Registrant hereby undertakes to respond to requests for information that is incorporated by reference into the proxy statement/prospectus pursuant to Items 4, 10(b), 11 or 13 of this registration statement on Form S-4, within one business day of receipt of such request, and to send the incorporated documents by first class mail or other equally prompt means. This includes information contained in documents filed subsequent to the effective date of the registration statement through the date of responding to the request.

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(8) The undersigned Registrant hereby undertakes to supply by means of a post-effective amendment all information concerning a transaction, and the company being acquired involved therein, that was not the subject of and included in the registration statement when it became effective.

(9) The undersigned registrant hereby undertakes to deliver or cause to be delivered with the prospectus, to each person to whom the prospectus is sent or given, the latest annual report to security holders that is incorporated by reference in the prospectus and furnished pursuant to and meeting the requirements of Rule 14a-3 or Rule 14c-3 under the Securities Exchange Act of 1934; and, where interim financial information required to be presented by Article 3 of Regulation S-X are not set forth in the prospectus, to deliver, or cause to be delivered to each person to whom the prospectus is sent or given, the latest quarterly report that is specifically incorporated by reference in the prospectus to provide such interim financial information.

(10) The registrant undertakes to send to each limited partner at least on an annual basis a detailed statement of any transactions with the General Partner or its affiliates, and of fees, commissions, compensation and other benefits paid, or accrued to the General Partner or its affiliates for the fiscal year completed, showing the amount paid or accrued to each recipient and the services performed.

(11) The registrant undertakes to provide to the limited partners the financial statements required by Form 10-K for the first full fiscal year of operations of the partnership.

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the Registrant pursuant to the foregoing provisions, or otherwise, the Registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer or controlling person of the Registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the Registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

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SIGNATURES

Pursuant to the requirements of the Securities Act, the Registrant has duly caused this Amendment No. 7 to Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in Houston, Texas, on the 26th day of January, 2015.

SANCHEZ PRODUCTION PARTNERS LLC

By: /s/ Stephen R. Brunner
Name: Stephen R. Brunner
Title: President, Chief Executive Officer and Chief Operating Officer

Pursuant to the requirements of the Securities Act of 1933, as amended, this Registration Statement has been signed by the following persons in the capacities and the dates indicated.

Signature	Title	Date
/s/ Stephen R. Brunner Stephen R. Brunner	President, Chief Executive Officer and Chief Operating Officer	January 26, 2015
/s/ Charles C. Ward Charles C. Ward	Principal Financial Officer and Principal Accounting Officer	January 26, 2015
* Alan S. Bigman	Manager	January 26, 2015
* Richard S. Langdon	Manager	January 26, 2015
* G. M. Byrd Larberg	Manager	January 26, 2015
* Antonio R. Sanchez	Manager	January 26, 2015
*	Manager	January 26, 2015

Gerald F. Willinger

* /s/ Stephen R. Brunner
Stephen R. Brunner
Attorney-in-fact

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EXHIBIT INDEX

2.1	Plan of Conversion (included as Annex A to the proxy statement/prospectus)
4.1*	Form of Certificate of Conversion of Sanchez Production Partners LLC
4.2*	Form of Certificate of Limited Partnership of Sanchez Production Partners LP
4.3	Form of Agreement of Limited Partnership of Sanchez Production Partners LP (included as Annex B to the proxy statement/prospectus)
4.4*	Form of Certificate of Formation of Sanchez Production Partners GP LLC
4.5*	Form of Limited Liability Company Agreement of Sanchez Production Partners GP LLC
4.6*	Form of First Amended and Restated Limited Liability Company Agreement of Sanchez Production Partners GP LLC
4.7	Form of Sanchez Production Partners LP Long-Term Incentive Plan (included as Annex C to the proxy statement/prospectus)
5.1*	Opinion of Andrews Kurth LLP as to the legality of the securities
8.1*	Tax Opinion of Andrews Kurth LLP
23.1	Consent of KPMG LLP
23.2	Consent of PricewaterhouseCoopers LLP
23.3	Consent of Andrews Kurth LLP (included in opinions filed as Exhibits 5.1 and 8.1)
23.4	Consent of Netherland, Sewell & Associates, Inc.
24.1*	Powers of Attorney (included on signature page)
99.1	Form of Proxy for Holders of Sanchez Production Partners LLC Common Units
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Previously filed