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

Form 10-K

(Mark One)

☒

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 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.)
1000 Main Street, Suite 3000 Houston, Texas	**77002**
(Address of Principal Executive Offices)	(Zip Code)

Telephone Number: (713) 783-8000
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units representing Class B Limited Liability Company Interests	NYSE MKT LLC

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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. (Check one):

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

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

Aggregate market value of Sanchez Production Partners LLC Common Units, without par value, held by non-affiliates as of June 30, 2014 was approximately $51,634,210 based upon NYSE MKT LLC closing price.

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 March 2, 2015: 28,777,014 common units.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements in this Annual Report on Form 10-K contain or may contain forward-looking statements. These statements, identified by words such as “plan”, “anticipate”, “believe”, “estimate”, “should”, “expect”, “may”, “will”, “could”, “project”, “intend”, “predict”, “potential”, “pursue”, “target”, “continue” and similar expressions include our expectations and objectives regarding our future financial position, operating results and business strategy. These statements are subject to known and unknown risks, uncertainties and other factors, which may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. These forward-looking statements were based on various factors and were derived utilizing numerous assumptions and other factors that could cause our actual results to differ materially from those in the forward-looking statements. These factors include, but are not limited to, our ability to secure suitable financing to continue with our existing business or change our business and conclude a merger, acquisition or combination with a business prospect, economic, political and market conditions and fluctuations, government and industry regulation, interest rate risk, U.S. and global competition and other factors. Most of these factors are difficult to predict accurately and are generally beyond our control. You should consider the areas of risk described in connection with any forward-looking statements that may be made herein. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. Readers should carefully review this report in its entirety, including but not limited to our financial statements and the notes thereto and the risks described herein. We advise you to carefully review the reports and documents we file from time to time with the Securities and Exchange Commission (SEC), particularly our quarterly reports on Form 10-Q and our current reports on Form 8-K. Except for our ongoing obligations to disclose material information under the Federal securities laws, we undertake no obligation to release publicly any revisions to any forward-looking statements, to report events or to report the occurrence of unanticipated events.

PART I

Item 1. Business

Overview

We are a limited liability company formed in 2005 under the laws of the State of Delaware. 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. 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 operate our oil and natural gas properties as one business segment: the exploration, development and production of oil and natural gas.

We completed our initial public offering on November 20, 2006, as Constellation Energy Partners LLC (CEP). On October 3, 2014, 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 by the Company’s unitholders. We currently trade on the NYSE MKT LLC (NYSE MKT) under the symbol “SPP”.

Unless the context requires otherwise, any reference in this Annual Report on Form 10-K to “Sanchez Production Partners”, “we”, “our”, “us”, “SPP” or the “Company” means Sanchez Production Partners LLC and its subsidiaries. References in this Annual Report on Form 10-K to “SOG” and “SEP I” are to Sanchez Oil & Gas Corporation and its affiliate, Sanchez Energy Partners I, LP, respectively.

Business Strategy

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:

- 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;
- 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
- 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.

Our primary operating focus has been to reduce our outstanding debt while maintaining a limited capital expenditure program to expand our oil and natural gas production and reserves. As part of this focus, during 2013, we sold our Robinson's Bend Field assets in the Black Warrior Basin of Alabama and used a portion of the proceeds from that sale to reduce our outstanding debt. As a result of this sale, amounts related to the Robinson's Bend Field assets have been reported as discontinued operations in 2013. All prior year information relating to the Robinson's Bend Field assets has been restated as discontinued operations, and all information reported or discussed in this Annual Report on Form 10-K reflects the treatment of the Robinson's Bend Field assets as discontinued operations. We also amended our reserve-based credit facility to extend its maturity to May 2017 and expand our borrowing capacity, and we acquired producing oil and natural gas assets in Texas and Louisiana from SEP I. These actions have allowed us to reduce our outstanding debt to $42.5 million at December 31, 2014. We intend to continue our business strategy to expand our production and reserves while actively pursuing opportunities, including merger and acquisitions, which could lead to enhanced unitholder value.

Oil and Natural Gas Properties

Our total estimated proved reserves at December 31, 2014, were approximately 99.8 Bcfe, approximately 75% of which were classified as proved developed, with 90% being natural gas and 10% being oil. At December 31, 2014, we owned approximately 2,025 net producing wells. Our total average proved reserve-to-production ratio is approximately 10.2 years and our portfolio decline rate is 12% to 17% based on our estimated proved reserves at December 31, 2014 and production for the month ended December 31, 2014.

Below is a description of our operations and our oil and natural gas properties by basin at December 31, 2014:

Cherokee Basin

The Cherokee Basin is located in the Mid-Continent region of the United States in southern Kansas, northern Oklahoma and western Missouri, and covers approximately 26,000 square miles. The predominant production is natural gas produced from coals and shales, and natural gas and oil from conventional formations. In 2007, we invested in the Cherokee Basin, pursuing a coalbed methane resource play targeting Pennsylvanian coals. As coalbed methane wells were drilled, oil zones were also found and, when economical, developed. Natural gas discovered with oil continues to be a value add, and is handled by our extensive existing natural gas and water gathering infrastructure.

Our production is primarily from the Pennsylvanian coals, shales and sands. Major zones are the Mulky Iron Post Shale, Weir Pitt Coal, and Skinner, Red Fork, and Bartlesville sands. Deeper Mississippian, Woodford (Devonian) and Arbuckle (Ordovician) formations are potentially productive, but currently minimal to our reserve values. The eastward movement of the Mid-Continent horizontal Mississippian drilling into Osage County continues to offer future value to our ownership position in the area if commercial success can be demonstrated.

Average Cherokee Basin well depth is approximately 2,000 feet in the western portion of the Basin (Osage County, Oklahoma) and approximately 1,000 feet in the eastern portion (Nowata County, Oklahoma). Similarly to depth, average well costs are approximately $340,000 in the west and approximately $170,000 in the east. Offsetting our lower drilling costs are the relatively low reserves and low daily production rates per well. Typical coalbed methane wells produce over a period of 20 to over 50 years, and on average have less favorable economic characteristics than conventional natural gas wells. A typical oil completion in these areas declines over one to two years and then produces at a steady rate similar to a coalbed methane well.

At December 31, 2014, we owned approximately 1,974 net producing wells in the Cherokee Basin. The natural gas coming from our wells is low pressure due to the shallow producing formations and compression is needed to move the natural gas to point of sale. We operate in excess of 20 booster compressors and stations to get our natural gas to sales points owned by ONEOK Gas Transportation, L.L.C.; Scissortail Energy, LLC; Enable Oklahoma Intrastate Transmission, LLC; and Southern Star Central Gas Pipeline, Inc. We operate a substantial portion of our production in the Cherokee Basin. We also own a 50% working interest in most wells operated by Bullseye Operating, L.L.C. (Bullseye) and a 50% interest in Bullseye itself. Bullseye operates approximately 500 gross wells in Washington and Nowata Counties in Oklahoma and sells its production through the Cotton Valley producers cooperative, Cotton Valley Compression, L.L.C. Our average gross working interest in our Cherokee Basin operated properties is approximately 98%. Our average gross working interest in our non-operated Cherokee Basin properties is approximately 50%.

Our estimated proved reserves in the Cherokee Basin at December 31, 2014 were approximately 89.2 Bcfe, approximately 72% of which were classified as proved developed, with 91% being natural gas and 9% being oil.

Woodford Shale

The Woodford Shale is located in the Arkoma Basin in southern Oklahoma. We own approximately nine net producing wells, located in Coal and Hughes counties. This area is gas-rich and is characterized by multiple productive zones. The production of natural gas in the Woodford Shale comes from shale rock that has been stimulated through fracturing jobs after a horizontal well has been drilled. Woodford Shale wells are typically 6,000 to 11,000 feet deep and cost approximately $3.3 million on average to drill and complete, with multiple fractures required. The gas-bearing shale section ranges from 120 to 200 feet thick. As of December 31, 2014, our 82 wells had an average gross working interest of 11.3% and an average net revenue interest of 9.1%. Approximately 90% of the wells are operated by affiliates of Devon Energy Corporation (Devon) and Newfield Exploration Mid-Continent, Inc. (Newfield), with the remaining wells operated by three additional companies. We do not have any additional drilling or leasehold rights associated with our Woodford Shale properties and expect declining production rates and limited future capital expenditures for these wells.

Our estimated proved reserves in the Woodford Shale at December 31, 2014 were approximately 4.2 Bcfe, all of which were classified as proved developed and all were natural gas.

Central Kansas Uplift

The Central Kansas Uplift is an oil-prone region located in Kansas and southern Nebraska. As of December 31, 2014, we had a gross acreage position of 3,710 acres, or approximately 893 net acres, and we owned approximately 5 net producing wells. Over 2 billion barrels of oil have been produced in this region from multiple horizons. The Ordovician Age Arbuckle Formation and the Upper Pennsylvanian Age Lansing—Kansas City reservoirs are the primary targets. Multiple completions per wellbore are common and the typical carbonate reservoirs are stimulated with an inexpensive acid treatment. Drilling depth for this region ranges from 3,500 to 4,900 feet depending on targets and location. Wells in this region typically cost approximately $450,000 to drill and complete.

Murfin Drilling Company, Inc., an experienced oil producer in Kansas, operates all of our wells in this region. The average gross working interest in the wells is approximately 20% and the average net revenue interest is approximately 16%.

Our estimated proved reserves in the Central Kansas Uplift at December 31, 2014 were approximately 0.3 Bcfe, approximately 100% of which were classified as proved developed, with 96% being oil.

Black Warrior Basin

All of the natural gas properties that we owned in the Black Warrior Basin at December 31, 2012, were sold to a third party on February 28, 2013, and a majority of the sales proceeds were used to reduce our outstanding debt level. These properties have been classified as discontinued operations in our consolidated financial statements.

Onshore Texas and Louisiana Gulf Coast

In August 2013, we acquired oil, natural gas and natural gas liquids assets in the onshore Texas and Louisiana Gulf Coast Region. The acquired assets include 67 producing wells. SOG operates assets located across the southern edge of the Texas coastline. Zachry Exploration, LLC (Zachry) operates assets located in onshore southern Louisiana. Drilled depths range from 9,000 to 12,000 feet mainly targeting the Miocene-Eocene-Paleocene Series sands and cost approximately $1.5 million to $2.0 million to drill and complete. The wells produce a combination of oil, natural gas and natural gas liquids and are typically vertical well bores. At December 31, 2014, there were 35 net working interest wells, producing a total of 948 barrels of oil equivalent per day. Approximately 74% of the wells are operated by SOG.

Our estimated proved reserves in Texas and Louisiana at December 31, 2014 were approximately 6.2 Bcfe, approximately 100% of which were classified as proved developed, with 65% being natural gas, 29% being oil and 6% being natural gas liquids.

Proved Oil, Natural Gas and Natural Gas Liquids Reserves

The following table reflects our estimates of proved oil, natural gas and natural gas liquids reserves based on the SEC definitions that were used to prepare our financial statements for the periods presented. The Standardized Measure values shown in the table are not intended to represent the current market values of our estimated proved oil and natural gas reserves.

Reserve data:	**2014**	**2013**
Estimated proved reserves:		
Oil (MMBbl)	1.7	2.1
Natural gas (Bcf)	89.5	78.0
Natural gas liquids (MMBbl)	0.1	0.1
Total proved reserves (Bcfe)	99.8	91.3
Estimated proved developed reserves:		
Oil (MMBbl)	1.6	1.9
Natural gas (Bcf)	65.2	66.6
Natural gas liquids (MMBbl)	0.1	0.1
Total proved developed reserves (Bcfe)	74.6	78.7
Estimated proved undeveloped reserves:		
Oil (MMBbl)	0.1	0.2
Natural gas (Bcf)	24.3	11.4
Natural gas liquids (MMBbl)	-	-
Total proved undeveloped reserves (Bcfe)	25.1	12.6
Proved developed reserves as a percent of total reserves	75%	86%
Standardized Measure (in millions)[(a)]	$ 119.5	$ 143.7

(a) Standardized Measure is the present value of estimated future net revenues to be generated from the production of proved reserves. It is determined using SEC-required prices and costs in effect as of the time of estimation without giving effect to non-property related expenses (such as general and administrative expenses or debt service costs) and discounted using an annual discount rate of 10%. Our Standardized Measure does not include the impact of derivative transactions or future federal income taxes because we are not subject to federal income taxes.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production. The SEC provides a complete definition of proved reserves, proved developed reserves and proved undeveloped reserves in Rule 4-10(a) of Regulation S-X.

At December 31, 2014 and 2013, Netherland, Sewell & Associates, Inc. (NSAI), an independent petroleum engineering firm, prepared an estimate of all our proved reserves. We used NSAI's estimates of our proved reserves to prepare our financial statements. NSAI maintains a degreed staff of highly competent technical personnel. The average experience level of their technical staff of engineers, geoscientists and petro physicists exceeds 20 years, including 5 to 15 years with a major oil company. Our technical staff of engineers and geosciences professionals has an average experience level that exceeds 27 years. Our activities with NSAI are coordinated by a reservoir engineer employed by us who has approximately 34 years of experience in the oil and natural gas industry and an engineering degree from the University of Tennessee and a masters of business administration from the University of New Orleans. He is a member of the Society of Petroleum Engineers. He has prior reservoir engineering and reserves management experience at Exxon Mobil Corporation, Dominion Resources and Hilcorp Energy. He has extensive experience in managing oil and natural gas reserves processes. He serves as the key technical person on our internal reserves committee, which reviews the reserve reports prepared by NSAI before the reports are reviewed by our audit committee of our board of managers and approved by our board of managers.

We have a successful track record of developing our proved undeveloped reserves. We do not rely on any proprietary technology to drill our development wells. Based on our organizational structure and our current business plans, our forecasted cash flow over the next five years is expected to be sufficient to fund this type of development drilling program on certain of our proved undeveloped locations. Using the SEC guidelines for estimating proved reserves, 94% of the locations are scheduled to be drilled within the next five years with the remaining small fraction of 6% being drilled in 2020 as part of a continuous capital program. We record our proved undeveloped locations typically at one offset location, but we can also record proved undeveloped locations on one section surrounding existing production subject to available infrastructure. We have the right to develop locations under our concession agreement with the Osage Nation in Osage County, Oklahoma, subject to its terms and conditions, until 2020 and we have leasehold availability for our other proved undeveloped locations.

The following table summarizes our inventory of proved undeveloped locations as of December 31, 2014:

	Year PUD Is Scheduled To Be Developed				
	2015	2016	2017	2018	2019
Number of Locations	17	0	100	110	56
Equivalents-Bcfe	1.0	0.0	8.5	9.9	4.5
Capital Estimate-$millions	$ 4.9	$ 0.0	$ 12.2	$ 14.0	$ 5.9

Our 2014 estimates of total proved reserves increased 8.5 Bcfe from 2013 due to a 12.9 Bcf increase in undeveloped gas reserves in the Cherokee Basin. The higher volumes were due to a higher gas price. Our reserves are 90% 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: $93.95 per barrel for oil, $35.11 per barrel for natural gas liquids and $4.09 per Mcf for natural gas. Proved developed producing reserves were lower due to natural production decline.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The Standardized Measure shown should not be considered the current market value of our reserves. The 10% discount factor used to calculate present value, which is required, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Oil, Natural Gas and Natural Gas Liquids Prices

We have generally sold our natural gas production based upon an index price reported in *Inside FERC's Gas Market Report* (Inside FERC) or at spot market prices applicable to the location of our natural gas production. Our realized pricing is primarily driven by the Inside FERC prices for Enable Gas Transmission, LLC (East), Natural Gas Pipeline Co. of America (Midcontinent), ONEOK Gas Transportation LLC (Oklahoma), Panhandle Eastern Pipe Line Co. (Texas, Oklahoma) and Southern Star Central Gas Pipeline Inc. (Texas, Oklahoma, Kansas) with respect to our properties in the Cherokee Basin; the Inside FERC price for Enable Gas Transmission, LLC (East) with respect to our properties in the Woodford Shale; the Inside FERC price for Tennessee Gas Pipeline Co. (Texas, zone 0), Texas Eastern Transmission Corp. (South Texas zone) and Houston Ship Channel market center with respect to our properties along the Gulf Coast and the applicable monthly average posted oil price with respect to our properties in the Central Kansas Uplift, the Cherokee Basin and the Gulf Coast. The following table summarizes year-end closing prices for the major indexes applicable to our business:

	Prices on January 1,		
Market Prices:	**2015**	**2014**	**2013**
Natural gas price—NYMEX (Henry Hub)	$ 3.19	$ 4.41	$ 3.35
Natural gas price—Enable Gas Transmission, LLC (East)[a]	$ 3.03	$ 4.30	$ 3.24
Natural gas price—Natural Gas Pipeline Co. of America (Midcontinent)	$ 3.04	$ 4.37	$ 3.26
Natural gas price—Houston Ship Channel	$ 3.04	$ 4.31	$ 3.32
Natural gas price—ONEOK Gas Transportation LLC (Oklahoma)	$ 3.02	$ 4.31	$ 3.24
Natural gas price—Panhandle Eastern Pipe Line Co. (Texas, Oklahoma)	$ 3.07	$ 4.27	$ 3.23
Natural gas price—Southern Natural Gas Co. (Louisiana)	$ 3.17	$ 4.37	$ 3.40
Natural gas price—Southern Star Central Gas Pipeline Inc. (Texas, Oklahoma, Kansas)	$ 3.06	$ 4.28	$ 3.20
Natural gas price—Tennessee Gas Pipeline Co. (Texas, zone 0)	$ 3.05	$ 4.26	$ 3.28
Natural gas price—Texas Eastern Transmission Corp. (South Texas zone)	$ 3.08	$ 4.29	$ 3.27
Oil price—West Texas Intermediate—Cushing	$ 53.45	$ 98.17	$ 91.83

(a) Previously called CenterPoint Energy Gas Transmission Co. (East)

We enter into derivative transactions in the form of hedging arrangements to reduce the impact of oil and natural gas price volatility on our cash flow from operations. Currently, we use fixed price swaps to hedge oil and natural gas prices. We also use basis swaps to limit our exposure to differences between the NYMEX natural gas price and the price at the location where we sell our natural gas. 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 fluctuating commodity prices on our cash flow from operations for those periods. All of our commodity derivative positions are outlined in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Cash Flow From Operations — Open Commodity Hedge Positions.”

Production and Price History

The following table sets forth information regarding net production of oil, natural gas and natural gas liquids and certain price and cost information for each of the periods indicated:

	For the Year Ended December 31, 2014	2013
Net Production:		
Natural gas production (MMcf)	6,911	6,727
Oil production (MBbl)	286	221
Natural gas liquids production (MBbl)	71	22
Total production (Mmcfe)	9,052	8,188
Average daily production (Mcfe/d)	24,800	22,433
Average Sales Prices:		
Natural gas price per Mcf with hedge settlements	$ 5.25	$ 5.78
Natural gas price per Mcf without hedge settlements	$ 4.14	$ 3.51
Oil and liquids price per Bbl with hedge settlements	$ 80.58	$ 89.15
Oil and liquids price per Bbl without hedge settlements	$ 80.78	$ 88.14
Total price per Mcfe with hedge settlements	$ 7.19	$ 7.49
Total price per Mcfe without hedge settlements	$ 6.34	$ 5.56
Average Unit Costs Per Mcfe:		
Field operating expenses[(a)]	$ 2.67	$ 2.62
Lease operating expenses	$ 2.32	$ 2.30
Production taxes	$ 0.35	$ 0.32
General and administrative expenses	$ 1.82	$ 2.71
Depreciation, depletion and amortization	$ 1.94	$ 2.32
Asset impairments	$ 0.60	$ 0.29

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

Productive Wells

The following table sets forth information at December 31, 2014, relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of producing commercial quantities of oil or natural gas, including oil and natural gas wells awaiting pipeline connections to commence deliveries. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Natural Gas		Oil	
	Gross	Net	Gross	Net
Operated	1,618	1,569	227	212
Non-operated	517	224	66	20
Total	2,135	1,793	293	232

Drilling Activity

The following table sets forth information with respect to oil and natural gas wells drilled and completed by us during the years ended December 31, 2014 and 2013, respectively. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that are capable of producing commercial quantities of oil or natural gas, regardless of whether they produce a reasonable rate of return. No exploratory wells were drilled on any of our properties during the years ended December 31, 2014 or 2013.

	Year Ended December 31, 2014	Year Ended December 31, 2013	Wells in Progress at December 31, 2014
Gross:			
Development			
Productive	11	64	2
Dry	-	-	-
Recompletions	6	15	-
Total	17	79	2
Net:			
Development			
Productive	8	64	-
Dry	-	-	-
Recompletions	6	15	-
Total	14	79	-

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2014 related to our leasehold acreage.

	Developed Acreage[(a)]		Undeveloped Acreage[(b)]	
	Gross[(c)]	Net[(d)]	Gross[(c)]	Net[(d)]
Total	236,055	214,553	20,162	16,227

(a) Developed acres are acres pooled within or assigned to productive wells/units.
(b) Undeveloped acres are acres on which wells have not been drilled or acres that have not been pooled into a productive unit.
(c) A gross acre is an acre in which a working interest is either fully or partially leased. The number of gross acres may include minerals not under lease as a result of leasing some but not all joint mineral owners under any given tract.
(d) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Leases

Our leases are concentrated in Oklahoma (84%), Texas (7%), Kansas (7%) and Louisiana (2%). We have approximately 1,564 leases in the Cherokee Basin on approximately 221,273 net acres. Our acreage includes areas leased under a concession agreement that we have with the Osage Nation in Osage County, Oklahoma, which provides us with the exclusive right to lease for coalbed methane on up to 560,000 acres within Osage County and the exclusive right for a period of 90 days after drilling a coalbed methane well on any such acreage to lease for oil and natural gas on such acreage. Generally, we have the right each year to elect to license up to a certain amount of acreage under the concession agreement for such year for a specified license payment, and a license must be obtained before we then lease the acreage. During the term of the concession agreement, however, we have the exclusive right to lease the acreage covered thereunder for coalbed methane unless we notify the Osage Nation in writing that we have no intention to lease any particular acreage. Our concession agreement with the Osage Nation is in four phases: (i) Phase I (four year term of January 1, 2005 through December 31, 2008) during which not less than 440 production wells were to have been drilled and completed; (ii) Phase II (four year term of January 1, 2009 through December 31, 2012) during which a cumulative of not less than 680 production wells were to have been drilled and completed; (iii) Phase III (four year term of January 1, 2013 through December 31, 2016) during which a cumulative of not less than 920 production wells shall be drilled and completed; and (iv) Phase IV (four year term of January 1, 2017 through December 21, 2020) during which a cumulative of not less than 1,160 production wells shall be drilled and completed, such that not less than a total of 1,160 production wells shall be drilled in Phases I through IV. Generally, in addition to the drilling and completion of a producing well counting as a "production well," the drilling of two dry holes are counted as one "production well," a recompletion of an existing wellbore is counted as one "production well," a horizontal well is counted as two "production wells" and a salt water disposal well is counted as one "production well" under the concession agreement (hereinafter "production well credits"). As of December 31, 2014, we believe we have earned approximately 794 total production well credits and our total developed and undeveloped leased acreage totaled 63,600 acres. We achieved the specific drilling targets under the concession agreement through Phase II, which ended December 31, 2012. If the drilling requirement for a particular phase is not met, we have the option to make a payment equal to the shortfall of production wells required to be drilled multiplied by $50,000 per well in order to be deemed to have complied with the requirement for that phase. If the drilling requirement of a particular phase were not met (either through drilling of production wells or payment as described above), the Osage Nation's sole remedy would be the termination of the concession agreement at the expiration of the then current phase, provided that such termination would have no effect upon our wells already drilled and the leases that we have acquired that are producing in paying quantities. We believe the Osage Nation has granted at least two concessions for the drilling of conventional oil and natural gas on acreage which overlaps certain of the acreage covered by our earlier granted concession and it has taken the position that we are not entitled to conventional oil and natural gas leases under the terms of our concession agreement where we have not drilled a coalbed methane well first.

The typical oil and natural gas lease agreement covering our other Cherokee Basin properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on or pooled with the leased property. In the Cherokee Basin, depending on the location of a particular well, the total lease burden on our operated properties is generally 20%, generally corresponding to an 80% net revenue interest to us, and on our non-operated properties is generally a 40% net revenue interest. We have 58 leases with a gross acreage position of 3,710 acres in the Central Kansas Uplift, or approximately 893 net acres. We have no leasehold rights associated with our 82 well bores in the Woodford Shale. We have approximately 116 leases in Louisiana with a gross acreage position of 3,594 acres, or approximately 714 net acres. We have approximately 380 leases in Texas with a gross acreage position of 17,623 acres, or 7,900 net acres.

Under the oil and natural gas lease agreements covering our productive wells, such leases have generally been perpetuated beyond their stated lease term and generally will not expire unless and until associated production ceases. Such leases are said to be "held by production" and do not require us to make lease payments beyond the royalty amount stipulated by each lease. The area held by production from a particular well is typically held by lease or applied to a pooled unit for such well or as specified under state law. Barring establishment of commercial production, most of our leases not currently held by production will expire. Approximately 15%, 11% and 5% of our total net undeveloped acreage of 16,227 acres is held under leases that have remaining primary terms expiring in 2015, 2016 and 2017, respectively. Of these expiration amounts in 2015, 2016, and 2017, approximately 58%, 72%, and 95%, respectively, apply to our concession agreement with the Osage Nation. If these leases do expire, we have the exclusive right to acquire a new coalbed methane lease on any expired acreage under our concession agreement with the Osage Nation until its expiration in 2020 or any earlier termination according to its terms and conditions. The remaining expiring acreage in all three years is primarily located in Kansas and Oklahoma.

Operations

General

We were the operator of approximately 88% of the 2,025 net wells in which we owned an interest at December 31, 2014. The administration and operation of our properties may be divided into the following functions:

Executive Management

Our executive management team develops and approves our business plans. They report directly to our board of managers, which is composed of three independent managers and two managers appointed by the holders of our Class A units. We have the responsibility for the overall operations of our fields and developing our drilling programs and other production enhancement opportunities. Field operations and the related technical support services, including geology, engineering, land administration and accounting, are conducted by employees of SOG and one of our subsidiaries. These employees approve the design and the development, maintenance, recompletion and workover for all of the wells in our fields. Our drilling programs are designed by us and implemented by various contractors. We do not own drilling rigs or other oil field service equipment used for drilling wells on our properties.

On May 8, 2014, the Company and SP Holdings, LLC (the Manager), a SOG-related company, 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. 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 one-time $1,000,000 administrative fee, which was paid in 2014, (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.

Field Operations

Our day-to-day operations in the Cherokee Basin are conducted by field employees of one of our subsidiaries under the supervision of our management team. The majority of the field operations team is composed of employees that were transitioned to us as a result of the acquisitions we made in the basin. This group is responsible for the operation of the existing production wells, pipelines, compressors and water handling facilities, as well as interaction with regulatory authorities with regard to permitting and compliance matters. In addition, they assist with the execution of the drilling and maintenance programs and the management of the contractors responsible for the drilling and completion of these wells. We currently have field offices located in Coffeyville, Kansas and Skiatook, Oklahoma.

Historically, when we drill new wells in the Cherokee Basin, our construction and roustabout services have been provided by various third party vendors. The drilling rigs have been provided by and our vertical wells drilled by Pense Bros. Drilling Co., Inc. and our directional drilling done by Scientific Drilling International, Inc. Other contract vendors conduct the cementing operations, provide well logging services and provide the design for, and execute upon, the well stimulation program. We evaluate our service providers in the basin from time to time.

For our 82 well bores located in the Woodford Shale, the operators of the properties—primarily Devon and Newfield—conduct all operations on our behalf. For our 26 non-operated wells located in the Central Kansas Uplift, Murfin Drilling Company Inc., the operator, conducts all operations on our behalf. For our 68 non-operated wells located in Texas, SOG is the operator and conducts all operations on our behalf. For our 23 non-operated wells located in Louisiana, Zachry is the operator and conducts all operations on our behalf.

Geology and Engineering

Our technical team is located in our corporate headquarters in Houston, Texas, and our field office in Skiatook, Oklahoma. We have retained engineers, geologists and consultants who have experience in drilling and producing both conventional oil and natural gas, as well as coalbed methane reserves. As a result, we have the ability to draw from a base of experienced and capable talent to select drilling locations and completion approaches to improve productivity and generate and test new ideas to improve production and reserves from existing wells through the use of recompletions, optimizing compression and gathering systems. NSAI, an independent petroleum engineering firm, has been retained to prepare the estimates for all of our proved reserves.

Land Administration

Our lease positions and our concession with the Osage Nation are managed by employees of SOG under the Services Agreement with assistance from contract landmen. These employees and landmen provide assistance with management of our current lease positions, acquisitions of new leases, permitting for drilling and laying pipelines as well as negotiating agreements with landowners for the use of their property. We have land staff in our field offices as required, with our land administration function in Houston, Texas.

Marketing and Major Customers

We manage our oil and natural gas marketing efforts and actively monitor our credit exposure to our major customers. We currently sell our natural gas produced in the Cherokee Basin to Macquarie Energy LLC; Keystone Gas Corporation; Scissortail Energy, LLC; Cotton Valley Compression, L.L.C.; Cherokee Basin Pipeline, LLC and ONEOK Energy Services Company, L.P. Our oil production in the Cherokee Basin is primarily purchased by Sunoco Partners Marketing and Terminals L.P. and Coffeyville Resources Refining and Marketing, LLC. Our natural gas production in the Woodford Shale and our oil production in the Central Kansas Uplift is marketed by the operators of our properties. Our natural gas and oil production in the onshore Texas and Louisiana Gulf Coast region is marketed by the operators of our properties.

Hedging and Risk Management Activities

Our hedging and risk management activities are managed by employees of SOG under the Services Agreement. Their activities are monitored by our risk committee composed of internal employees and quarterly risk reports are made to our board of managers and to the audit committee of our board of managers. All of our derivatives are with Societe Generale, a lender in our reserve-based credit facility, and The Bank of Nova Scotia. The derivative transactions are done to reduce our exposure to short-term fluctuations in oil and natural gas prices and interest rates and to achieve more predictable cash flows. None of our derivatives currently require cash collateral and we do not enter into speculative or proprietary trading activities. We also maintain an active insurance program to provide for coverage to insure against various losses and liabilities arising from our operations and drilling activities.

Markets and Competition

We operate in a competitive environment for acquiring properties, marketing oil and natural gas and retaining trained personnel. Many of our competitors have substantially greater financial, technical and personnel resources than us. As a result, our competitors may be able to outbid us for oil and natural gas properties and exploratory prospects, more competitively price their production, or utilize superior technical resources than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a competitive environment with limited access to capital. There is substantial competition for the limited capital available for investment in the oil and natural gas industry. SOG nor any of its related companies are restricted from competing with us.

We are also affected by competition for drilling rigs, completion rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling and completion rigs, equipment, pipe and personnel, which has delayed development drilling activities and has caused significant increases in the prices for this equipment and personnel. We are unable to predict when, or if, such shortages may occur or how they would affect our development and drilling program. To date, however, we have not experienced such shortages. In addition, over the past several years, our field employees have been working with teams of drilling and completion contractors and have developed relationships that should enable us to mitigate the risks associated with equipment availability.

Title to Properties

When we acquire our interests in oil and natural gas properties, we obtain a title opinion or perform a review on the most significant leases in the fields. As a result, title opinions or reviews have been obtained on a significant portion of our properties. In some instances, and as is customary in our industry, we conduct only a cursory review of the title to certain properties on which we do not have proved reserves. To the extent title opinions or other investigations reflect title requirements on those properties, we are typically responsible for curing any material title matters at our expense. We generally will not commence drilling operations on a property until we have cured or waived any such title matters or deemed the title risk sufficiently mitigated to justify proceeding with operations on the property.

We believe that we have satisfactory title to all of our material assets. Title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry. We believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or will materially interfere with our use in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties to operate our business.

Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, state, local and Native American tribal laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentrations of various substances, including water and waste, that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible in the absence of such regulations. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, federal, state, local and Native American tribal authorities frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

Environmental laws and regulations that could have a material impact on the oil and natural gas industry and our operations include the following:

Waste Handling

The Resource Conservation and Recovery Act (RCRA), and comparable state laws, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency (EPA), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most other wastes associated with the exploration, development and production of oil and natural gas are currently regulated under RCRA's non-hazardous waste provisions. Although we do not believe the current costs of managing any of our wastes are material under presently applicable laws, any future reclassification of oil and natural gas exploration, development and production wastes as hazardous wastes, could increase our costs to manage and dispose of wastes.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed of, or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease or operate numerous properties that have been used for oil and natural gas exploration and production for a number of years. Although we believe operating and waste disposal practices utilized in the past with respect to these properties were typical for the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges

The Federal Water Pollution Control Act (the Clean Water Act), and comparable state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, impose investigatory or remedial obligations and issue injunctions limiting or preventing our operations for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the Cherokee Basin, water is pumped from producing wells, collected and injected into approved salt water disposal wells in the deeper Arbuckle formation.

Oil Pollution Act

The Oil Pollution Act was enacted in 1990 to amend the Clean Water Act in large part due to the Exxon Valdez incident. Under the Oil Pollution Act, the EPA was directed to promulgate regulations which would create a comprehensive prevention, response, liability and compensation program to deal with oil discharged into United States navigable waters. In particular, the regulations developed under the Oil Pollution Act strengthened the requirements that apply to Spill Prevention, Control and Countermeasure Plans. The Oil Pollution Act imposes liability for removal costs and damages resulting from an incident in which oil is discharged into navigable waters and establishes liability for damages for injuries to, or loss of, natural resources.

Air Emissions

The Clean Air Act, and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. For example, in August 2012, the EPA adopted new rules that establish new air emission control requirements for oil and natural gas production and natural gas processing operations. The new rules include New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs) and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The new regulations require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of “green completions” for hydraulic fracturing, which requires the operator to recover or treat rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The rules also establish specific requirements regarding emissions from new or modified compressors, dehydrators, storage tanks and other production equipment. In addition, the rules establish new leak detection requirements for new or modified natural gas processing plants. Compliance with these rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. States can also impose air emissions limitations that are more stringent than the federal standards imposed by the EPA. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Rules restricting air emissions may require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our operating results. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities. We believe our operations are in substantial compliance with federal and state air emission standards.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing practices and has commenced a study of the potential environmental impacts of hydraulic fracturing activities. Further, the Department of the Interior has released draft regulations governing hydraulic fracturing on federal and Native American oil and natural gas leases which would require lessees to file for approval of well stimulation work before commencement of operations and require well operators to disclose the trade names and purposes of additives used in the fracturing fluids. The states in which we operate have also adopted disclosure requirements related to fracturing fluids. Legislation has been introduced, but not adopted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Currently, no states in which we utilize hydraulic fracturing have adopted these regulations. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing hydraulic fracturing would impact our business.

OSHA and Other Laws and Regulation

We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state laws. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communications standard, OSHA Process Safety Management, the EPA community right-to-know regulations under Title III of CERCLA and similar state laws require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements.

Our operations in the Cherokee Basin and in the Woodford Shale in Oklahoma are subject to the rules and regulations of the Oklahoma Corporation Commission, Oil & Gas Conservation Division. Our operations in the Cherokee Basin and the Central Kansas Uplift in Kansas are subject to the rules and regulations of the Kansas Corporation Commission, Oil & Gas Conservation Division. Our operations in Texas are subject to the rules and regulations of the Railroad Commission of Texas, Oil & Gas Division. Our operations in Louisiana are subject to the rules and regulations of the Louisiana Department of Natural Resources, Office of Conservation. We believe we are in substantial compliance with these rules and regulations.

We believe that we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements should not have a material adverse impact on our financial condition and results of operations. As of December 31, 2014, we had no accrued environmental obligations. We are not aware of any environmental issues or claims that will require material capital expenditures or that will otherwise have a material impact on our financial position or results of operations. However, we cannot predict how future environmental laws and regulations may impact our operations, and therefore cannot provide assurance that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial condition, results of operations or cash flows.

Employees

As of December 31, 2014, our subsidiary, CEP Services Company, Inc., had 52 employees. None of these employees are subject to a collective bargaining agreement.

As of December 31, 2014, 22 employees were employed by SOG with their primary function being to provide services for SPP. None of these employees are subject to a collective bargaining agreement.

Offices

We are headquartered in Houston, Texas. We also maintain field offices in Coffeyville, Kansas and Skiatook, Oklahoma. We own the field office buildings and land in Kansas and Oklahoma.

Available Information

Our internet address is *http://www.sanchezproductionpartners.com*. We make our website content available for informational purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Annual Report on Form 10-K. We make available free of charge on or through our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC maintains an internet website that contains these reports at *http://www.sec.gov*. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information concerning the operation of the Public Reference Room may be obtained by calling the SEC at (800) 723-0330.

Item 1A. Risk Factors

As a smaller reporting company, we are not required to provide the information required by this item.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties is included in "Item 1. Business," and is incorporated herein by reference.

Our obligations under our reserve-based credit facility are secured by mortgages on our oil and natural gas properties, as well as a pledge of all ownership interests in our material subsidiaries. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Reserve-Based Credit Facility", in this Annual Report on Form 10-K for additional information concerning our reserve-based credit facility.

Item 3. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any 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.

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 $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 Constellation Energy Partners Holdings, LLC (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.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities

Our common units are listed on the NYSE MKT under the symbol "SPP." On March 2, 2015, there were 28,777,014 common units outstanding and 55 unitholders of record. On March 2, 2015, the market price for our common units was $1.36 per unit, resulting in an aggregate market value of units held by non-affiliates of approximately $31.5 million. The following table presents the high and low closing price for our common units during the periods indicated.

	Common Stock	
	High	Low
2014		
First Quarter	$ 2.85	$ 2.17
Second Quarter	$ 2.74	$ 2.30
Third Quarter	$ 4.23	$ 2.63
Fourth Quarter	$ 3.71	$ 1.22
2013		
First Quarter	$ 1.82	$ 1.17
Second Quarter	$ 2.13	$ 1.50
Third Quarter	$ 2.95	$ 1.85
Fourth Quarter	$ 2.47	$ 2.10

We have not paid distributions on our common units since June 2009.

Subject to the terms of our reserve-based credit facility, our operating agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date. Available cash generally means, for any quarter ending prior to liquidation:

(a) the sum of:

(i) all cash and cash equivalents that we and our subsidiaries (or our proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly-owned) have on hand at the end of that quarter; and

(ii) all additional cash and cash equivalents that we and our subsidiaries (or our proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly-owned) have on hand on the date of determination of available cash for that quarter resulting from working capital borrowings made subsequent to the end of such quarter,

(b) less the amount of any cash reserves established by the board of managers (or our proportionate share of cash reserves in the case of subsidiaries that are not wholly-owned) to:

(i) provide for the proper conduct of the business of us and our subsidiaries (including reserves for future capital expenditures including drilling and acquisitions and for anticipated future credit needs) subsequent to such quarter,

(ii) comply with applicable law or any loan agreement, security agreement, mortgage, debt instrument or other agreement or obligation to which we or any of our subsidiaries are a party or by which we are bound or our assets are subject; or

(iii) provide funds for distributions (1) to our unitholders or (2) in respect of our Class D interests or Class C management incentive interests with respect to any one or more of the next four quarters;

provided, however, that the board of managers may not establish cash reserves pursuant to (iii) above if the effect of such reserves would be that we are unable to distribute the quarterly distribution on all common units and Class A units with respect to such quarter; and provided further, that disbursements made by us or any of our subsidiaries or cash reserves established, increased or reduced after the end of that quarter, but on or before the date of determination of available cash for that quarter, shall be deemed to have been made, established, increased or reduced, for purposes of determining available cash, within that quarter if the board of managers so determines. In June 2014, we cancelled the Class D interests and the Class C management incentive interests.

Item 6. Selected Financial Data

As a smaller reporting company, we are not required to provide the information required by this item.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with accompanying financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, forecasts, guidance, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, operating costs, lack of a sponsor, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in "Forward-Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

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:

- 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;
- reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient and effective hedging programs; and
- organically grow our business by increasing reserves and production through what we believe to be low-risk development drilling that focuses on capital production growth and oil opportunities on our existing properties.

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 Annual Report on Form 10-K to "Sanchez Production Partners", "we", "our", "us", "SPP" or the "Company" means Sanchez Production Partners LLC (formerly Constellation Energy Partners) and its subsidiaries. References in this Annual Report on Form 10-K to "SOG" and "SEP I" are to Sanchez Oil & Gas Corporation and its subsidiary, Sanchez Energy Partners I, LP, respectively.

Some key highlights of our business activities for the year ended December 31, 2014 were:

- We acquired producing oil and natural gas assets in Louisiana.
- We entered into the Services Agreement with SP Holdings, LLC as the Manager as of July 1, 2014. The Manager provides services that we require to operate our business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals and acquisition, disposition and financing services.
- We changed our name from Constellation Energy Partners LLC to Sanchez Production Partners LLC on October 3, 2014.
- We have reduced our outstanding debt by 80.7% from a high of $220.0 million in 2009 to $42.5 million.

Significant Operational Factors in 2014

- *Realized Prices.* Our average realized prices for the year ended December 31, 2014 were $5.25 per Mcfe for natural gas and $91.94 per barrel for oil, including hedge settlements, and $4.14 per Mcf for natural gas and $92.19 per barrel for oil, excluding hedge settlements. After deducting the cost of sales associated with our third party gathering, our average realized prices were $5.03 per Mcf for natural gas and $86.74 per barrel for oil, including hedge settlements, and $3.92 per Mcf for natural gas and $86.98 per barrel for oil, excluding hedge settlements.
- *Production.* Our production for the year ended December 31, 2014, was approximately 9.1 Bcfe, or an average of 24,800 Mcfe per day, compared with approximately 8.2 Bcfe, or an average of 22,433 Mcfe per day, for the year ended December 31, 2013.
- *Capital Expenditures and Drilling Results.* For the year ended December 31, 2014, we spent approximately $7.2 million in cash capital expenditures, consisting of $1.4 million for the purchase of oil and natural gas properties in LaSalle Parish, Louisiana, $3.5 million in development expenditures focused on oil completions in the Cherokee Basin, and $2.3 million in development expenditures focused on SEP I acquired properties. We completed 8 net wells and 6 net recompletions during 2014.
- *Oil and Natural Gas Reserves.* Our total year-end 2014 proved reserves were 99.8 Bcfe, which is 8.5 Bcfe higher than our year-end 2013 proved reserves of 91.3 Bcfe, due to higher SEC natural gas prices. Our 2014 estimates of proved reserves were prepared in accordance with the SEC rules for oil and natural gas reserve reporting that require our proved reserves to be calculated using an average of the NYMEX spot prices for the sales of oil and natural gas on the first calendar day of each month of the year, adjusted for basis differentials. Locations that are scheduled to be drilled after five years are generally classified as probable or possible reserves. Our reserves are 90% natural gas and are sensitive to lower SEC-required prices for natural gas and basis differentials in the Mid-Continent region. The 12-month average SEC-required price used to prepare our reserve report was $4.09 per Mcf. 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. We do not use the SEC-required 12-month average price to make investment or drilling decisions. Instead, we use estimates of expected future observable market prices for oil and natural gas.
- *Reduction of Outstanding Debt.* Through December 31, 2014, we reduced our outstanding debt to $42.5 million, which currently leaves us with $27.5 million of funds available for borrowing under our reserve-based credit facility which matures on May 30, 2017.
- *Hedging Activities.* All of our derivatives are accounted for as mark-to-market activities. For the year ended December 31, 2014, the non-cash mark-to-market gain was approximately $12.2 million, compared to non-cash mark-to-market loss of $17.3 million for the same period in 2013.

  We experience earnings volatility as a result of using the mark-to-market accounting method for our open derivative positions. This accounting treatment can cause extreme earnings volatility as the positions for future oil and natural gas production or interest rates are marked-to-market. These non-cash gains or losses are included in our current statement of operations until the derivatives are cash settled as the commodities are produced and sold or interest payments are made. Further detail of our open derivative positions and their accounting treatment is outlined below in “—Cash Flow From Operations—Open Commodity Hedge Positions” and “Critical Accounting Polices and Estimates—Hedging Activities.”

Results of Operations

The following table sets forth the selected financial and operating data for the periods indicated (in thousands, except net production and average sales and costs):

	For the year ended December 31,		2014 vs. 2013 Variance	
	2014	2013	$	%
Revenues:				
Natural gas sales at market price	$ 25,481	$ 20,999	4,482	21.3 %
Natural gas hedge settlements	7,695	15,550	(7,855)	(50.5) %
Natural gas mark-to-market activities	(1,824)	(16,528)	14,704	89.0 %
Natural gas total	31,352	20,021	11,331	56.6 %
Oil sales	26,353	20,944	5,409	25.8 %
Oil hedge settlements	(69)	245	(314)	(128.2) %
Oil mark-to-market activities	14,053	(753)	14,806	1,966.3 %
Oil total	40,337	20,436	19,901	97.4 %
Natural gas liquids sales	2,477	512	1,965	383.8 %
Miscellaneous income	3,106	3,108	(2)	(0.1) %
Total revenues	77,272	44,077	33,195	75.3 %
Operating expenses:				
Lease operating expenses	21,012	18,858	2,154	11.4 %
Cost of sales	1,487	1,455	32	2.2 %
Production taxes	3,200	2,601	599	23.0 %
General and administrative	16,499	22,214	(5,715)	(25.7) %
Loss on sale of assets	223	4	219	5,475.0 %
Depreciation, depletion and amortization	17,533	18,972	(1,439)	(7.6) %
Asset impairments	5,424	2,357	3,067	130.1 %
Accretion expenses	604	519	85	16.4 %
Total operating expenses	65,982	66,980	(998)	(1.5) %
Other expenses (income):				
Interest expense	2,076	6,798	(4,722)	(69.5) %
Interest expense - gain from mark-to-market activities	-	(3,648)	3,648	100.0 %
Other income	(289)	(196)	(93)	47.4 %
Total other expenses (income)	1,787	2,954	(1,167)	(39.5) %
Total expenses	67,769	69,934	(2,165)	(3.1) %
Loss from discontinued operations	-	(2,686)	2,686	100.0 %
Net income (loss)	$ 9,503	$ (28,543)	38,046	133.3 %
Net production:				
Natural gas production (MMcf)	6,911	6,727	184	2.7 %
Oil production (MBbl)	286	221	65	29.4 %
Natural gas liquids production (MBbl)	71	22	49	222.7 %
Total production (Mmcfe)	9,052	8,188	864	10.6 %
Average daily production (Mcfe/d)	24,800	22,433	2,367	10.6 %
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 5.25	$ 5.78	(0.53)	(9.2) %
Natural gas price per Mcf without hedge settlements	$ 4.14	$ 3.51	0.63	17.9 %
Oil and natural gas liquids price per Bbl with hedge settlements	$ 80.58	$ 89.15	(8.57)	(9.6) %
Oil and natural gas liquids price per Bbl without hedge settlements	$ 80.78	$ 88.14	(7.36)	(8.4) %
Total price per Mcfe with hedge settlements	$ 7.19	$ 7.49	(0.30)	(4.0) %
Total price per Mcfe without hedge settlements	$ 6.34	$ 5.56	0.78	14.0 %
Total price per BOE with hedge settlements	$ 43.11	$ 44.96	(1.85)	(4.1) %
Total price per BOE without hedge settlements	$ 38.06	$ 33.39	4.67	14.0 %
Average unit costs per Mcfe:				
Field operating expenses[a]	$ 2.67	$ 2.62	0.05	1.9 %
Lease operating expenses	$ 2.32	$ 2.30	0.02	0.9 %
Production taxes	$ 0.35	$ 0.32	0.03	9.4 %
General and administrative expenses	$ 1.82	$ 2.71	(0.89)	(32.8) %
General and administrative expenses without unit-based compensation	$ 1.68	$ 2.59	(0.91)	(35.1) %
Depreciation, depletion and amortization	$ 1.94	$ 2.32	(0.38)	(16.4) %

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

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Oil, natural gas and natural gas liquids sales. Unhedged oil, natural gas and natural gas liquids sales increased by $11.9 million, or 28.0%, to $54.3 million for the year ended December 31, 2014, from $42.4 million for the year ended December 31, 2013, due to higher production volumes and higher natural gas prices, partially offset by lower oil prices. Higher natural gas prices resulted in an increase in revenues of approximately $4.4 million. Lower oil prices resulted in a decrease in revenues of approximately $2.1 million, while lower natural gas liquids prices resulted in a decrease in revenues of approximately $0.5 million.

Average daily production volumes increased to approximately 24,800 Mcfe/d for the year ended December 31, 2014, from approximately 22,433 Mcfe/d for the year ended December 31, 2013. Higher oil, natural gas and natural gas liquids production volumes resulted in an increase in revenues of approximately $10.0 million. The increase in average daily production was primarily the result of properties purchased in Texas and Louisiana during August 2013, which provided a full year of production in 2014. We hedged 88% of our consolidated production volumes sold through December 31, 2014, and hedged all of our actual production through December 31, 2013. In March 2013, we liquidated or repositioned certain of our hedges to ensure that our outstanding derivative positions in future periods are lower than our expected future natural gas production in those periods.

Cash hedge settlements received for our commodity derivatives were approximately $7.6 million for the year ended December 31, 2014. Cash hedge settlements received for our commodity derivatives were approximately $15.8 million for the year ended December 31, 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 $29.5 million for the year ended December 31, 2014, compared to the same period in 2013. Our realized prices before our hedging program increased from 2013 to 2014 primarily due to net higher market prices for our natural gas production. This was offset by our hedging program and the mark-to-market gains and losses discussed below.

Hedging and mark-to-market activities. As of December 31, 2014, all of our hedges were accounted for as mark-to-market activities. For the year ended December 31, 2014, the non-cash mark-to-market gain was approximately $12.2 million, compared to a non-cash mark-to-market loss of approximately $17.3 million for the same period in 2013. The entire 2014 non-cash gain represented the impact of lower than expected future oil and natural gas prices on our derivative transactions that were being accounted for as mark-to-market activities.

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

For the year ended December 31, 2014, lease operating expenses increased $2.1 million, or 11.4%, to $21.0 million, compared to expenses of $18.9 million for the same period in 2013. This $2.1 million increase in lease operating expenses is related to $1.4 million in higher non-operated costs due to the properties purchased in Texas and Louisiana during August 2013 incurring a full year of expenses, $0.4 million in higher elective costs such as parts and supplies and $0.3 million in higher labor costs.

For the year ended December 31, 2014, per unit lease operating expenses were $2.32 per Mcfe compared to $2.30 per Mcfe for the same period in 2013.

For the year ended December 31, 2014, production taxes increased $0.6 million, or 23.0%, to $3.2 million, compared to production taxes of $2.6 million for the same period in 2013. This increase is primarily the result of higher market prices for natural gas in 2014.

General and administrative expenses. General and administrative expenses include the costs of our employees and SOG employees who perform services under the Services Agreement, related benefits, professional fees, general business and public company expenses, and any other administrative costs not directly associated with field operations.

General and administrative expenses decreased $5.7 million, or 25.7%, to $16.5 million for the year ended December 31, 2014, compared to $22.2 million for the same period in 2013. Our general and administrative expenses were lower in 2014, compared to 2013 because of $7.0 million in lower audit, consulting, and legal services and $0.8 million in lower severance costs, partially offset by $1.0 million in higher management fees paid to SOG in conjunction with the Services Agreement, $0.7 million in higher labor and incentive compensation costs and $0.4 million in higher unit-based compensation and board of managers costs,. The decreased legal fees are the result of the PostRock Litigation and the settlement of $5.9 million during 2013.

Depreciation, depletion and amortization expense and Asset impairments. Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition and equipment costs. Asset impairment expense is incurred when the fair value of our assets is less than their historical net book value. Depletion is calculated using units-of-production. Assuming everything else remains unchanged, as natural gas production changes, depletion would change in the same direction.

Our depreciation, depletion and amortization expense for the year ended December 31, 2014 was $17.5 million, or $1.94 per Mcfe, compared to $19.0 million, or $2.32 per Mcfe, for the same period in 2013. This decrease of $1.4 million, or 7.6%, reflects the increase in our reserve base at December 31, 2014, primarily due to the impact of a higher SEC-required natural gas price used to calculate our reserves, as well as increases in our current year reserve volumes. We calculate depletion using units-of-production under the successful efforts method of accounting. Our other assets are depreciated using the straight-line basis. We will use our 2014 year-end reserve report to record our depletion in the first three quarters of 2015 and our 2015 year-end reserve report to record our depletion in the fourth quarter of 2015.

Our asset impairment charges for the year ended December 31, 2014 were $5.4 million, compared to $2.4 million for the same period in 2013. Our impairment charges in 2014 were approximately $5.4 million to impair the value of our oil and natural gas fields in Texas and Louisiana as a result of lower oil prices. Our 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, both due to decreases in commodity pricing.

Interest expense. Net interest expense for the year ended December 31, 2014 decreased $1.0 million, or 34.1%, to approximately $2.1 million, compared to approximately $3.1 million in interest expense for the same period in 2013. This decrease was due to a lower average debt outstanding balance during 2014 compared to 2013, along with a lower average interest rate. At December 31, 2014, we had an outstanding balance under our reserve-based credit facility of $42.5 million, compared to $50.7 million at December 31, 2013.

Discontinued Operations. We did not have any discontinued operations gains or losses during 2014 and recorded a loss from discontinued operations for the year ended December 31, 2013 of $2.7 million. Our discontinued operations represent the net loss associated with the sale of our Robinson’s Bend Field assets in the Black Warrior Basin of Alabama, in a transaction that closed on February 28, 2013, with an effective date of December 1, 2012.

Liquidity and Capital Resources

During 2014, we utilized our cash flow from operations as our primary source of capital to fund our operating and capital programs, as well as certain non-recurring items, and to reduce our debt. 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, settlement payments related to the PostRock Litigation and the Exelon Litigation and transition costs related to the implementation of the Services Agreement.

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 2015, we anticipate that our cash flow from operations can meet our planned capital expenditures and other cash requirements for the next twelve months. If needed, we may utilize unused borrowing capacity under our reserve-based credit facility or issue additional equity securities to raise additional capital. Future cash flows and our borrowing capacity are subject to a number of variables, including the level of oil and natural gas production, the market prices for those products and our hedge position. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain our current debt level, planned levels of capital expenditures, operating expenses or any cash distributions that we may make to unitholders.

During 2014, natural gas prices showed signs of tapering, while oil prices decreased dramatically. We have a significant amount of our oil and natural gas production hedged for 2015 and 2016. Our financial results will not be fully impacted by significant increases or decreases in oil and natural gas prices because of our hedging program. For 2015, we have approximately 4.5 Bcfe of our natural gas production locked in at an effective fixed price of $4.26 per Mcfe. With respect to our 2015 oil production, we have hedges in place on approximately 259 MBbl at a fixed price of $91.04 per barrel. These hedge positions lock in a significant portion of our expected operating cash flows for 2015, although we are still exposed to increases or decreases in oil and natural gas prices on any of our unhedged volumes. In the event of inflation increasing drilling and service costs, our hedging program will also limit our ability to have increased revenues recoup the higher costs, which could further impact our planned capital spending or operating expense levels.

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 date 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 December 31, 2014, we had borrowed $42.5 million under our reserve-based credit facility and our borrowing base was $70.0 million. At December 31, 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 December 31, 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 3.50 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 (a) any person or two or more persons acting as a group acquiring beneficial ownership of 35% or more of the outstanding shares of voting stock of the Company or (b) individuals who constitute the current Class B managers of the Company's current board of managers cease for any reason to constitute at least a majority of the Company's board of managers; provided however, that any individual becoming a Class B manager whose election, or nomination for election by the Company's unitholders, was approved by a vote of at least a majority of the Class B managers then comprising the current board, shall be considered as though such person was a Class B manager of the current board of managers, but excluding any such person whose initial assumption of office occurs as a result of either an actual or threatened election contest or other actual or threatened solicitation of proxies or consents by or on behalf of a person other than the Company's board of managers. Neither of these events have occurred, so no change in control had occurred as of December 31, 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 and the payment of fees and expenses. As of December 31, 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, nor to the Services Agreement between us and SP Holding, LLC, a SOG-related company.

At December 31, 2014, we were in compliance with the financial covenants contained in our reserve-based credit facility. We monitor compliance on an ongoing basis. As of December 31, 2014, our actual Total Net Debt to actual Adjusted EBITDA ratio was 1. 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 5.6 to 1.0, compared to a required ratio of not less than 1.0 to 1.0; and our actual Adjusted EBITDA to cash interest expense ratio was 13.3 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, 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 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.

Cash Flow from Operations

Our net cash flow provided by operating activities for the year ended December 31, 2014, was $17.0 million, compared to net cash flow provided by operating activities of $15.2 million for the same period in 2013. This increase in cash flow from operations was attributable to the impact of higher oil, liquid and natural gas sales of $54.3 million for 2014 compared to $42.5 million for the same time period in 2013 and gains on mark-to-market activities for 2014.

Our cash flow from operations is subject to many variables, the most significant of which are the volatility of oil and natural gas prices and our level of production of oil and natural gas. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through our development program or completing acquisitions, as well as the market prices of oil and natural gas and our hedging program. For additional information on our business plan for 2015, refer below to *"Outlook."*

Open Commodity Hedge Positions

We enter into hedging arrangements to reduce the impact of oil and natural gas price volatility on our operations. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations. 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.

The following tables as of December 31, 2014, summarize, for the periods indicated, our hedges currently in place through December 31, 2016. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps—NYMEX (Henry Hub)

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
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
									8,310,181	

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
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
									473,800	

Investing Activities—Acquisitions and Capital Expenditures

Cash used by investing activities was $6.4 million for the year ended December 31, 2014, compared to $22.1 million of cash provided by investing activities for the same period in 2013. Our cash capital expenditures were $1.4 million for the purchase of oil and natural gas properties in LaSalle Parish, Louisiana, $3.5 million in development expenditures focused on oil completions in the Cherokee Basin, and $2.3 million in development expenditures focused on SEP I acquired properties. We completed 8 net wells and 6 net recompletions during 2014.

During 2013, we 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 $0.2 million in distributions from an equity affiliate. Our cash capital expenditures were $35.9 million, consisting of $15.3 million in development expenditures focused on oil completions in the Cherokee Basin, $0.1 million to acquire certain additional natural gas wells in the Cherokee Basin, $20.2 million to acquire oil and natural gas properties in Texas and Louisiana, and $0.4 million in development expenditures focused on the oil and natural gas properties acquired in Texas and Louisiana.

We anticipate that we will use cash flow from operations to acquire assets that will allow us to grow our asset base, recapitalize the Company and reinstate our distribution.

The amount and timing of our capital expenditures is largely discretionary and within our control. If oil or natural gas prices decline to below acceptable levels, and the borrowing base under our reserve-based credit facility is reduced, drilling costs escalate, or our efforts to exploit oil potential in our asset base prove to be unsuccessful, we could choose to defer a portion of these planned capital expenditures until later periods. We routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, availability of funds under our reserve-based credit facility, and internally generated cash flow. These and other matters are outside of our control and could affect the timing of our capital expenditures. Future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that our operations and other capital resources will provide cash in sufficient amounts during 2015 to maintain our planned levels of capital expenditures, to maintain the outstanding debt level under our reserve-based credit facility or to commence any quarterly distribution to unitholders. Our capital expenditures are also impacted by drilling and service costs. In the event of inflation increasing drilling and service costs, our hedging program will limit our ability to have increased revenues recoup the higher costs, which could further impact our planned capital spending.

Financing Activities

Our net cash used in financing activities was $11.2 million for the year ended December 31, 2014, compared to $34.4 million used in financing activities for the same period in 2013. During 2014, we had borrowings under our reserve-based credit facility of $5.8 million for working capital purposes and repayments of $14.0 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 2014 to fund the cost of units tendered by employees for tax withholdings for unit-based compensation.

We used $50.2 million of cash in 2013 to reduce our outstanding balance under our reserve-based credit facility. This debt reduction was funded from a portion of the proceeds from the sale of our Robinson's Bend Field assets in the Black Warrior Basin of Alabama. We also had borrowings under our reserve-based credit facility of $16.9 million during 2013, which were used as a portion of the purchase price for the properties that we acquired in Texas and Louisiana.

At December 31, 2014, we had $42.5 million in outstanding debt and had approximately $0.7 million in debt issue costs remaining to be amortized. Our reserve-based credit facility matures on May 30, 2017.

Off-Balance Sheet Arrangements

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

Credit Markets and Counterparty Risk

We actively monitor the credit exposure and risks associated with our counterparties. Additionally, we continue to monitor global credit markets to limit our potential exposure to credit risk where possible. Our primary credit exposures result from the sale of oil and natural gas and our use of derivatives. Through December 31, 2014, we have not suffered any significant losses with our counterparties as a result of nonperformance.

Certain key counterparty relationships are described below:

Macquarie Energy LLC

Macquarie Energy LLC (Macquarie), a subsidiary of Sydney, Australia-based Macquarie Group Limited, purchases a portion of our natural gas production in the Cherokee Basin. We have received a guarantee from Macquarie Bank Limited for up to $2.0 million in purchases through December 31, 2015 and up to $2.0 million in purchases through January 31, 2016. As of December 31, 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 December 31, 2014, we had no past due receivables from Scissortail.

Derivative Counterparties

As of December 31, 2014, all of our derivatives were 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 December 31, 2014, each of these financial institutions had an investment grade credit rating. Several of the lenders in our reserve-based credit facility were, as of December 31, 2014, on review for possible ratings downgrade by S&P or Moody's. However, it would take a multiple ratings downgrade for each of these banks to fall below investment grade.

Reserve-Based Credit Facility

As of December 31, 2014, the banks and their percentage commitments in our reserve-based credit facility were: Societe Generale (36.36%), OneWest Bank, FSB (36.36%) and BOKF NA, dba Bank of Oklahoma (27.28%). As of December 31, 2014, each of these financial institutions had an investment grade credit rating.

Outlook

Our results of operations are heavily influenced by oil and natural gas prices, which have significantly declined in recent months. Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply and demand for oil and natural gas, market uncertainty, economic conditions and a variety of additional factors. Oil prices began to decline during 2014 and in the last quarter of 2014 a rapid decline in oil prices occurred. Since our inception, oil and natural gas prices have experienced significant fluctuations and additional changes in commodity prices may affect our economic viability of and ability to fund drilling projects.

Given the uncertainty regarding the timing and magnitude of a recovery of crude oil and natural gas prices, we have planned to reduce capital spending in 2015. Our primary goals during the next 12 months include: preserving liquidity and financial strength; limiting new borrowings and capital investments, reducing general and administrative expenses and reducing per unit lease operating costs.

If these low prices continue, we will experience lower revenues and cash flows until the prices improve. If commodity prices remain low, we may also recognize further impairments of our producing properties if the expected future cash flows from these properties become insufficient to recover their carrying value. Further, we may recognize additional impairments of our unevaluated properties should we determine that we no longer intend to retain these properties for future development.

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. Below, we have provided a discussion of certain critical accounting policies, estimates and judgments. Please read Note 1 to our consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Oil and Natural Gas Properties

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

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. The 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. As more fully described in Note 15 to the consolidated financial statements, proved reserves estimates are subject to future revisions when additional information becomes available.

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

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. Cash flow estimates for the impairment testing are based on third party reserve reports and exclude derivative instruments. Refer to Note 7 to our consolidated financial statements for additional information.

Unproven properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred. Impairment is deemed to have occurred if a lease is going to expire prior to any planned drilling on the leased property. Valuation allowances based on average lease lives are maintained for the value of unproved properties. For our concession in Osage County, Oklahoma, we assess it for impairment on a quarterly basis, and if it is considered impaired, a charge to expense is made when such impairment is deemed to have occurred.

Oil, Natural Gas and Natural Gas Liquids Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil, natural gas and natural gas liquids that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Management estimates the proved reserves attributable to our ownership based on various factors, including consideration of reserve reports prepared by NSAI, an independent petroleum engineering firm. On an annual basis, our proved reserve estimates and the reserve report prepared by NSAI are reviewed by the audit committee of our board of managers and our board of managers. Our financial statements for 2013 and 2014 were prepared using NSAI's estimates of our proved reserves.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. We prepared our reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The accuracy of our 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.

Our 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 actual quantities of oil and natural gas eventually recovered.

Revenue Recognition

Sales are recognized when oil, natural gas and natural gas liquids have 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 is reasonably assured and the sales price is fixed or determinable. Oil, natural gas and natural gas liquids are generally sold on a monthly basis. Most of the contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a specific tank battery, gathering or transmission line, quality of oil, natural gas and natural gas liquids, and prevailing supply and demand conditions, so that the price of the oil, natural gas and natural gas liquids fluctuates to remain competitive with other available oil, natural gas and natural gas liquids supplies. As a result, revenues from the sale of oil, natural gas and natural gas liquids will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our oil, natural gas and natural gas liquids contracts are customary in the industry.

Gas imbalances occur when sales are more or less than the entitled ownership percentage of total gas production. 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 material gas imbalance positions at December 31, 2014 and 2013.

Hedging Activities

We have implemented a hedging program to limit our exposure to changes in commodity prices or basis differentials for our oil and natural gas sales and to mitigate the impact of volatility of changes in the LIBOR interest rate on the interest payments for our debt. We do not enter into speculative trading positions.

We account for all our open derivatives as mark-to-market activities using the mark-to market accounting method. Using this method, the contracts are carried at their fair value on our consolidated balance sheet 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 statement of operations under the captions "Natural gas sales" and "Oil sales", which comprise our total revenues for commodity derivatives. Settled interest rate swaps are recognized as "Interest expense" on our consolidated statement of operations.

We experience earnings volatility as a result of using the mark-to-market accounting method. This accounting treatment can cause earnings volatility as the positions related to future oil and natural gas production or future interest payments are marked-to-market. These non-cash unrealized gains or losses are included in our current Statement of Operations until the derivatives are cash settled as the commodities are produced and sold or the interest is paid. Increases in the market price of oil or natural gas and interest rates relative to the fixed future prices for our hedges, result in unrealized, non-cash mark-to-market losses on those derivatives and lower reported net income. Decreases in the market price of oil or natural gas or interest rates relative to the fixed future prices for our hedges, result in unrealized, non-cash mark-to-market gains on those derivatives and higher reported net income. Although these gains and losses are required to be reported immediately in earnings as market prices change, the fair value of the related future physical transaction is not marked-to-market and therefore is not reflected as revenues or expenses or as an accounts receivable or accounts payable in our financial statements. This mismatch impacts our reported results of operations and our reported working capital position until the derivatives are cash settled and the future physical transaction occurs. Upon cash settlement of the derivatives, the sale of the physical commodity or interest payment at then-current market prices offsets the previously reported mark-to-market gains or losses such that the cumulative net cash realized results in a net sale of the physical oil and natural gas production or interest payment at the fixed future prices for our hedge. When our derivative positions are cash settled, the realized gains and losses of those derivative positions are included in our statement of operations as natural gas sales, oil and natural gas liquids sales, or interest expense depending on the derivative.

If we were to account for our derivatives as cash flow hedges, we would record changes in the fair value of derivatives designated as hedges that are effective in offsetting the variability in cash flows of forecasted transactions in other comprehensive income until the forecasted transactions occur. At the time the forecasted transactions occur, we would reclassify the amounts recorded in other comprehensive income into earnings. We would record the ineffective portion of changes in the fair value of derivatives used as hedges immediately in earnings. When amounts for hedging activities are reclassified from "Accumulated other comprehensive income (loss)" on the balance sheet to the Statement of Operations, we would record settled oil and natural gas derivatives as "Oil and gas sales" and settled interest rate swaps as "Interest expense (income)."

Recent Accounting 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 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 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 will not be material.

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. The adoption of this guidance will have no material impact on our financial position, results of operations or cash flows.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

As a smaller reporting company, we are not required to provide the information required by this item.

Item 8. Financial Statements and Supplementary Data

The Reports of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required to be filed under this item are presented in "PART IV. Item 15. Exhibits and Financial Statement Schedules" of this Annual Report on Form 10-K, and are incorporated herein by reference.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer (CEO) and the Chief Financial Officer (CFO) 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 December 31, 2014 (the Evaluation Date). Based on such evaluation, the CEO and the

CFO 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 CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

During the three months ended December 31, 2014, there were no changes in our 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, our internal control over financial reporting.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) provides smaller reporting companies with a permanent exemption from the requirement to obtain an external audit on the effectiveness of internal financial reporting controls provided in Section 404(b) of the Sarbanes-Oxley Act. We utilized this exemption under the Dodd-Frank Act for the years ended December 31, 2014, and 2013. We still disclosed management's assessment of the effectiveness of internal control over financial reporting as required in Section 404(a) of the Sarbanes-Oxley Act. The use of this exemption was reviewed and approved by our audit committee.

Reports of Management

Financial Statements

The management of Sanchez Production Partners LLC (our, the Company or SPP) is responsible for the information and representations in our financial statements. We prepare the financial statements in accordance with accounting principles generally accepted in the United States of America based upon available facts and circumstances and management's best estimates and judgments of known conditions.

The audit committee of our board of managers, which consists of three independent managers, meets periodically with management, our internal auditor and KPMG to review the activities of each in discharging their responsibilities. Our internal auditor and KPMG have free access to the audit committee.

Management's Report on Internal Control Over Financial Reporting

Our management, under the direction of our principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rule 13a-15(f).

Our system of internal control over financial reporting is designed to provide reasonable assurance to our management and board of managers regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

Our management conducted an evaluation of the effectiveness of our internal control over financial reporting using the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable-not absolute-assurance to management and the board of managers regarding achievement of an entity's financial reporting objectives. Based upon the evaluation under this framework, management concluded that our internal control over financial reporting was effective as of December 31, 2014.

Item 9B. Other Information

None.

PART III

Item 10. Managers, Executive Officers and Corporate Governance

The following table shows information for members of our board of managers and our executive officers as of March 5, 2015. Members of our board of managers are elected for one–year terms, and our executive officers will hold office at the discretion of, and may be removed by, our board of managers.

Name	Age	Position with Sanchez Production Partners LLC
Alan S. Bigman	47	Independent Manager
Stephen R. Brunner	56	President, Chief Executive Officer and Chief Operating Officer
Richard S. Langdon	64	Independent Manager
G. M. Byrd Larberg	62	Independent Manager
Antonio R. Sanchez, III	41	Manager
Charles C. Ward	54	Chief Financial Officer, Treasurer and Secretary
Gerald F. Willinger	47	Manager

Alan S. Bigman has been an independent member of our board of managers since June 2014. Mr. Bigman is currently co-founder and Director of VistaTex Energy LLC, a privately held company created in 2010 to produce oil and natural gas from mature properties in the U.S., and Chairman of the board of directors of White Square Chemicals, Inc., a privately held, U.S.-based specialty chemical company. He was most recently Director, Capital Markets and M&A of KCAD Deutag, an oilfield services company based in Aberdeen, UK, from September 2011 to December 2012, where he was responsible for reorganizing and staffing the company's finance, corporate development and tax functions. From June 1996 to March 1998, Mr. Bigman was Senior Vice President of Access Industries, a privately held, U.S.-based industrial group with worldwide holdings. From March 1998 until September 2003, Mr. Bigman served as Vice President and Director of Corporate Finance of Tyumen Oil Company (TNK), a major Russian oil and gas producer and refiner, based in Moscow, Russia, and then as Vice President and Director of Corporate Finance for SUAL, a large Russian aluminum smelter, from September 2003 to September 2004. From September 2004 until December 2005, Mr. Bigman rejoined Access Industries as Senior Vice President, Investment and was based in London. In January 2006, Mr. Bigman was appointed Chief Financial Officer of Basell Polyolefins, an international chemicals company based in Hoofddorp, The Netherlands, where he served until January 2008. In January 2008, Mr. Bigman became the Chief Financial Officer of LyondellBasell Industries, a successor company to Basell Polyolefins and Lyondell, which had been merged. Mr. Bigman was Chief Financial Officer of LyondellBasell until August 2009, when he took on a consulting role with the company, and exited the company in March 2010. LyondellBasell filed for bankruptcy in January 2009. Prior to assuming the role of Chief Financial Officer at Basell Polyolefins, Mr. Bigman was on the company's board of directors, where he served as a member of the audit and compensation committees.

Stephen R. Brunner has served as our President and Chief Executive Officer since March 2008 and our Chief Operating Officer since February 2008. He has also served as a member of our board of managers from December 2008 until August 2011. Mr. Brunner also served as Vice President for Constellation Energy Commodities Group, Inc. (CCG) from February 2008 to January 2009. From 2001 until November 2007, Mr. Brunner served as Executive Vice President, Operations of Pogo Producing Company, an oil and gas exploration company.

Richard S. Langdon has been an independent member of our board of managers and our audit, compensation, conflicts and nominating and corporate governance committees since November 2006 and has served as the chairman of our board of managers since October 2011. Mr. Langdon is also currently the President, Chief Executive Officer and Chairman of KMD Operating Company LLC (KMD Operating), a position held since November 2011, a privately held exploration and production company. Mr. Langdon has been serving as the President and Chief Executive Officer of Gasco Energy, Inc., a publicly traded exploration and production company, since May 2013. Mr. Langdon has also served as a Director of Gasco Energy, Inc. since 2003. Mr. Langdon was the President and Chief Executive Officer of Matris Exploration Company L.P., a privately held exploration and production company (Matris Exploration), from July 2004 and Executive Vice President and Chief Operating Officer of KMD Operating from August 2009 until the merger of Matris Exploration into KMD Operating in November 2011, which merger was effective January 2011. Mr. Langdon also served as President and Chief Executive Officer of Sigma Energy Ventures, LLC, a privately held exploration and production company, from November 2007 until November 2013. From 1997 until 2002, Mr. Langdon served as Executive Vice President and Chief Financial Officer of EEX Corporation, a publicly traded exploration and production company that merged with Newfield Exploration Company in 2002. Prior to that, he held various positions with the Pennzoil Companies from 1991 to 1996, including Executive Vice President—International Marketing—Pennzoil Products Company; Senior Vice President—Business Development—Pennzoil Company; and Senior Vice President—Commercial & Control—Pennzoil Exploration & Production Company.

G. M. Byrd Larberg has been an independent member of our board of managers since June 2014. Mr. Larberg currently performs consulting services on an individual basis. From 2010 to 2012, Mr. Larberg served as a member of the board of directors of Risco Resources, a small independent exploration company headquartered in Jakarta, Indonesia, which was sold in 2012. Mr. Larberg served as a member of the board of directors of 3GIG, an exploration-focused software firm headquartered in Houston, Texas, from 2008 to 2013 and now serves as an advisor to the Board. He is active on the Board of the Houston Metropolitan YMCA, where he serves on the Financial Development Committee and as Chairman of the annual Partners Campaign. Previously he was a board member of Meridian Resources, a Houston-based exploration company, from 2007 until it was acquired by Alta Mesa in 2010. Mr. Larberg began his career at Shell Exploration and Production Company as a geologist in 1976. Over the next twenty-one years, he held various leadership positions within Shell, ending as Vice President of Exploration and Production, Africa and Latin America for Pecten International, an affiliate of Shell Oil Company, from 1993 to 1996. During his tenure he also served as Exploration Manager for Shell Western E&P Domestic USA Onshore, including the Mid Continent, from 1990 to 1993, and as the Division Exploration Manager for the Gulf Coast Division covering offshore Louisiana from 1987 to 1990. After successfully completing a fourteen month special assignment to the Director of New Business Development for Royal Dutch Shell's Worldwide Deepwater efforts, Mr. Larberg left Shell and joined Burlington Resources in 1998. From 1998 to 2006, Mr. Larberg held several key positions at Burlington Resources, beginning as Vice President of Exploration for Burlington Resources International. In 2000, Mr. Larberg was elected Executive Vice President and Chief Operating Officer of Burlington Resources International, a position he held until 2003, when he moved to the corporate office as Vice President of Geosciences. In this capacity, he was responsible for technical excellence for the Geology and Geophysical programs across the company, G&G technology business development, and management of the company-wide exploration portfolio. Mr. Larberg retired from Burlington Resources in March 2006 following the company's purchase by Conoco Phillips. Since such time, he has occasionally consulted in the areas of technical and portfolio management for exploration companies, including Pemex, Maersk, ONGC and Glopetrol.

Antonio R. Sanchez, III has been a member of our board of managers since August 2013. Mr. Sanchez has served as the President and Chief Executive Officer of Sanchez Energy Corporation (NYSE: SN), a publicly-traded exploration and production company, and has been a member of SN's board of directors since its formation in August 2011. He has been directly involved in the oil and gas industry for over 12 years. Mr. Sanchez, III is also the President of SOG, which he joined in October 2001, as well as the President of SEP Management I, LLC and a Managing Director of SEP I. In his capacities as a director and officer of these companies, Mr. Sanchez, III manages all aspects of their daily operations, including exploration, production, finance, capital markets activities, engineering and land management. From 1997 to 1999, Mr. Sanchez, III was an investment banker specializing in mergers and acquisitions with J.P. Morgan Securities Inc. From 1999 to 2001, Mr. Sanchez, III worked in a variety of positions, including sales and marketing, product development and investor relations, at Zix Corporation, a publicly traded encryption technology company (NASDAQ: ZIXI). Mr. Sanchez, III was also a member of the board of directors of Zix Corporation from May 2003 to June 2014.

Charles C. Ward has served as our Chief Financial Officer and Treasurer since March 2008. Mr. Ward also served as a Vice President of Constellation Energy Commodities Group, Inc. from November 2005 until December 2008. Prior to that time, he was a Vice President of Enron North America Corp. from March 2002 to November 2005.

Gerald F. Willinger has been a member of our board of managers since August 2013. Mr. Willinger is currently a Managing Partner of Sanchez Capital Advisors, LLC and Manager and Co-founder of Sanchez Resources, LLC, an oil and gas company, since February 2010. Mr. Willinger currently serves as a Director of Sanchez Resources. From 1998 to 2000, Mr. Willinger was an investment banker with Goldman, Sachs & Co. Mr. Willinger served in various private equity investment management roles at MidOcean Partners, LLC and its predecessor entity, DB Capital Partners, LLC, from 2000 to 2003 and at the Cypress Group, LLC from 2003 to 2006. Prior to joining Sanchez Capital Advisors, LLC, Mr. Willinger was a Senior Analyst for Silver Point Capital, LLC, a credit-opportunity fund, from 2006 to 2009.

Qualifications of Board of Managers

The holders of our Class A units elect two Class A managers and our Class B unitholders elect three Class B managers to our board of managers. Some of the key criteria for serving on our board of managers as a Class B manager include independence from SOG and its related companies, experience in the exploration and production industry, familiarity with master limited partnerships, and corporate governance, financial, or other management experience. Our Class B managers, and the specific experience, qualifications, attributes and skills that led the board to conclude that they should serve as managers, are:

- Mr. Bigman brings considerable financial, managerial, transaction and corporate governance experience to our board of managers. During his career, he has held management positions of increasing responsibility in major energy corporations throughout the world where he has successfully lead financings, financial restructurings, mergers and acquisitions involving companies focused on various aspects of the hydrocarbon value chain. With respect to upstream finance, as Vice President and Director of Corporate Finance for TNK, a leading Russian oil and gas producer, he raised capital to finance the growth of the company from its privatization in 1997 through a sale of a 50% stake to British Petroleum (BP) in 2003, creating TNK-BP, a $20 billion joint venture. In the area of corporate governance, Mr. Bigman served on the board of directors of Basell Polyolefins, where he was a member of the audit and compensation committees, which is beneficial for our board operations. He has also served on several international boards, including the board of Svyazinvest, Russia's largest telecommunications holding company. Presently, he is Chairman of the board of directors of White Square Chemicals Inc., a privately-held U.S.-based specialty chemicals company. Mr. Bigman is independent of SOG.

- Mr. Langdon brings to our board considerable financial and managerial experience in the energy industry as well as his entrepreneurial abilities, which are valuable to a small growing company such as us. He has served as the Chief Financial Officer of EEX Corporation, a publicly traded exploration and production company that merged with Newfield Exploration. He has also held significant commercial positions with the Pennzoil Companies, including roles in business development and marketing. He is also the founder and owner of two privately held oil and gas companies. Mr. Langdon has extensive experience in finance and accounting that adds significant value to the board's oversight role of our financial reporting. He has prior public company board and audit committee experience, which is beneficial for our board operations, and served as the chairman of the audit committee of Gasco Energy, Inc., a publicly traded exploration and production company until he was named Gasco's President and Chief Executive Officer. Mr. Langdon is independent of SOG.
- Mr. Larberg brings to our board significant technical, operational and financial management experience in the oil and natural gas industry. His background, which includes extensive geology training and education and encompasses a distinguished career at Shell Oil Company and Burlington Resources, provides a unique perspective on the dynamics of the oil and natural gas exploration and production industry. He has considerable governance experience, having previously served on the boards of Meridian Resources, a Houston-based exploration company acquired by Alta Mesa in 2010, Risco Resources, a small independent exploration company headquartered in Jakarta, Indonesia, and 3GIG, an exploration-focused software firm headquartered in Houston, Texas. He is also active on the Board of the Houston Metropolitan YMCA, where he serves on the Financial Development Committee and as Chairman of the annual Partners Campaign, which raised $6.5 million for underprivileged children under his leadership. Taken together, this wealth of experience is invaluable to our board as we look to grow the Company.

Our Class A unitholder has elected Messrs. Sanchez and Willinger as our two Class A managers to represent the Class A unitholder interests on our board. Our Class A managers, and the specific experience, qualifications, attributes and skills that led the Class A unitholder to conclude that they should serve as managers, are:

- Mr. Sanchez, III brings to our board substantial upstream oil and gas/energy industry experience in both public and private entities. In his current capacity as President and Chief Executive Office of Sanchez Energy Corporation, he brings the perspective of leading a quickly growing, publicly-traded upstream company focused on asset value maximization and the creation of shareholder value. In his current capacity as President of SOG, he brings particular expertise in operating multiple upstream oil and natural gas entities through a shared service model. He acts as a liaison with SEP I and ensures our board has a continuing dialogue with our significant unitholder.
- Mr. Willinger brings to our board substantial experience in risk management, finance and negotiated transactions in the energy industry. He has a valuable perspective on upstream master limited partnerships, which provides our board with unique insights into master limited partnership management and growth opportunities. Additionally, he brings an expansive network of both private and public capital providers, which is useful for our board when evaluating possible capital sources. Mr. Willinger also acts as a liaison between the Company and SEP I.

Corporate Governance

Board Leadership Structure and Risk Oversight

Our board has three independent members as Class B managers and two managers elected by our Class A unitholder. Our independent board members are currently serving or have served as members of senior management of other public companies and have served as managers or directors of other public companies. We have four board committees comprised solely of independent managers, with each of these committees having an independent manager serving as chair of the committee. We believe that the number of independent, experienced managers that make up our board benefits our Company and our unitholders.

Under our operating agreement and corporate governance guidelines, the chairman of the board is responsible for:

- chairing board meetings;
- scheduling and setting the agendas for board meetings and
- providing information to board members in advance of each board meeting.

In addition, the board of managers has designated the chairman of the nominating and corporate governance committee to act as "Lead Manager." In that capacity, the current chairman, Mr. G. M. Byrd Larberg, has the following duties and authority:

- presiding at all board meetings where the chairman of the board of managers is not present;
- serving as a liaison between the chairman of the board of managers and the independent managers;
- approving information sent to the board and agendas and meeting schedules for board meetings;
- calling meetings of the non-management managers;
- ensuring his availability for direct consultation upon request of a major unitholder;
- chairing the executive session of non-management managers; and
- serving as a contact for unitholder complaints, other than those involving auditing/accounting matters.

Interested parties may communicate directly with the Lead Manager by writing to the Secretary, Sanchez Production Partners LLC, 1000 Main Street, Suite 3000, Houston, Texas 77002.

In accordance with NYSE MKT requirements, our audit committee charter provides that the audit committee is responsible for overseeing the risk management function in the Company. While the audit committee has primary responsibility for overseeing risk management, our entire board of managers is actively involved in overseeing risk management for the Company. For example, on at least a quarterly basis, our audit committee and our full board receive a risk management report from the Company's chief financial officer. The full board also engages in periodic discussion with other Company officers as the board may deem appropriate. In addition, each of our board committees considers the risks within its area of responsibilities. For example, our compensation committee considers the risks that may be implicated by our executive compensation programs. We believe that the leadership structure of our board supports the board's effective oversight of our risk management.

On an annual basis, as part of our review of corporate governance, the board evaluates our board leadership structure to ensure that it remains the optimal structure for our Company and our unitholders. We recognize that different board leadership structures may be appropriate for companies with different histories and cultures, as well as companies with varying sizes and performance characteristics. We believe our current leadership structure, under which our chairman of the board and each of the board committees are chaired by independent managers and a Lead Manager assumes specified responsibilities, remains the optimal board leadership structure for our Company and our unitholders at this time.

During 2013 and 2014, the board of managers met eight and 11 times, respectively. Each Class B manager attended at least 75% of the meetings of the board and of each committee on which he served.

The board of managers has adopted a policy that encourages each manager to attend the annual meeting of unitholders. All of the persons then serving as our managers attended the 2013 annual meeting of unitholders.

Committees of the Board of Managers

Audit Committee

As described in the audit committee charter, the audit committee is directly responsible for the appointment, compensation, retention and oversight of the work of the independent public accountants to audit our financial statements, including assessing the independent auditor's qualifications and independence, and establishes the scope of, and oversees, the annual audit. The committee also approves any other services provided by public accounting firms. The board has delegated to the audit committee the review and approval of our decision to enter into derivative transactions and our exemption from the swap clearing and swap execution requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act). The audit committee provides assistance to the board in fulfilling its oversight responsibility to the unitholders, the investment community and others relating to the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor's qualifications and independence and the performance of our internal audit function. The audit committee oversees our system of disclosure controls and procedures and system of internal controls regarding financial, accounting, legal compliance and ethics that management and our board of managers established. In doing so, it will be the responsibility of the audit committee to maintain free and open communication between the committee and our independent auditors, the internal accounting function and management of our Company.

The board of managers has determined that the chairman of the audit committee is an "audit committee financial expert" as that term is defined in the applicable rules of the SEC.

The audit committee held four meetings in 2013 and five meetings in 2014. Mr. Bigman is chairman, and Messrs. Larberg and Langdon are members.

Compensation Committee

As described in the compensation committee charter, the compensation committee establishes and reviews general policies related to our compensation and benefits. The compensation committee determines and approves, or makes recommendations to the board of managers with respect to, the compensation and benefits of our board of managers and our named executive officers, employees and service providers.

The committee establishes and reviews general policies related to our compensation and benefits, and annually reviews and approves the compensation paid to our executive officers and non-employee managers. The committee also approves the annual performance-based bonus award pool and long-term incentive equity awards for all employees and service providers.

Our Chief Executive Officer makes recommendations to the compensation committee regarding the compensation for the executive officers, other than himself. Specific recommendations include base salary adjustments, targets and goals for the annual performance-based bonus plan and long-term incentive awards. The committee considers these recommendations in developing its own recommendations to our board of managers, which, in its sole discretion, determines compensation actions for the other executive officers. The committee considers and, in its sole discretion, makes the final determination about compensation actions for the Chief Executive Officer.

When assessing compensation actions for the Chief Executive Officer and the other executive officers, the compensation committee considers several factors including comparative market data, the level of achievement of our annual business plan, our performance against our peer group, individual executive officer performance, scope of job responsibilities and the individual's industry experience, technical skills and tenure with the Company.

Our compensation committee is authorized to retain compensation consultants at the Company's expense and obtain any compensation surveys or reports regarding the design and implementation of compensation programs that it may find necessary in designing, implementing or administering compensation programs. During 2013, the committee retained Meridian Compensation Partners, LLC (Meridian). The committee retained Meridian after a review of the independence factors included in the Dodd-Frank Act for compensation consultants and considering Meridian's independence based on such factors. The amount paid to Meridian was less than $37,000 in 2013, for which Meridian prepared a competitive review of the compensation of our executive officers, advised the compensation committee regarding the design of our incentive plans and assisted with other related matters. During 2014, the committee retained Longnecker & Associates (L&A) to provide the same services. The amount paid to L&A was $0.1 million in 2014.

The compensation committee held five meetings in 2013 and five meetings in 2014. Mr. Langdon is chairman, and Messrs. Bigman and Larberg are members.

Conflicts Committee

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 SOG or its related companies or our managers and executive officers. 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. However, the 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.

The conflicts committee held two meetings in 2013 and eight meetings in 2014. Mr. Larberg is chairman, and Messrs. Bigman and Langdon are members.

Nominating and Corporate Governance Committee

As described in the nominating and corporate governance committee charter, the nominating and corporate governance committee nominates candidates to serve on our board of managers. The nominating and corporate governance committee is also responsible for monitoring a process to review manager, board and committee effectiveness, developing and implementing our corporate governance guidelines, recommending committee members and committee chairpersons and otherwise taking a leadership role in shaping the corporate governance of our Company.

The nominating and corporate governance committee held five meetings in 2013 and four meetings in 2014. Mr. Larberg is chairman, and Messrs. Bigman and Langdon are members.

We maintain on our website, *www.sanchezproductionpartners.com*, copies of the charters of each of the committees of the board of managers (except the conflicts committee which does not have a charter), as well as copies of our Corporate Governance Guidelines, Code of Ethics for Chief Executive Officer, Chief Financial Officer and Principal Accounting Officer, and Code of Business Conduct and Ethics. Copies of these documents are also available in print upon request of our Corporate Secretary. The Code of Business Conduct and Ethics provides guidance on a wide range of conduct, conflicts of interest and legal compliance issues for all of our managers, officers and employees, including our Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. We will post any amendments to, or waivers of, the Code of Business Conduct and Ethics applicable to our Chief Executive Officer, Chief Financial Officer or Principal Accounting Officer on our website.

Nominations for Manager

The board of managers seeks diverse candidates who possess the background, skills and expertise to make a significant contribution to the board of managers, us and our unitholders. Annually, the nominating and corporate governance committee reviews the qualifications and backgrounds of the managers, as well as the overall composition of the board of managers, and recommends to the full board of managers the slate of Class B manager candidates to be nominated for election at the next annual meeting of unitholders. The board of managers has adopted a policy whereby the nominating and corporate governance committee will consider the recommendations of unitholders with respect to candidates for election to the board of managers and the process and criteria for such candidates will be the same as those currently used by us for manager candidates recommended by the board of managers or management. During 2014, there were no changes to the procedures for nominating candidates to our board of managers.

Our Corporate Governance Guidelines, a copy of which is maintained on our website, *www.sanchezproductionpartners.com*, include criteria that are to be considered by the nominating and corporate governance committee and board of managers in considering candidates for nomination to the board of managers. These criteria require that a candidate:

- has the business and/or professional knowledge and experience applicable to us, our business and the goals and perspectives of our unitholders;
- is well-regarded in the community, with a long-term, good reputation for highest ethical standards;
- has good common sense and judgment;
- has a positive record of accomplishment in present and prior positions;
- has an excellent reputation for preparation, attendance, participation, interest and initiative on other boards on which he or she may serve; and
- has the time, energy, interest and willingness to become involved with us and our future.

Within our Corporate Governance Guidelines there is no specific requirement that the nominating and corporate governance committee or the board of managers consider diversity in identifying candidates for nomination to the board of managers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our managers and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of ownership of our equity securities and reports of changes in ownership of our equity securities with the SEC. Such persons are also required by SEC regulation to furnish us with copies of all Section 16(a) forms they file.

Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and managers, we believe that during 2013 and 2014 all Section 16(a) reporting persons complied with all applicable filing requirements in a timely manner.

Certifications

The NYSE MKT requires the Chief Executive Officer of each listed company to certify annually that he is not aware of any violation by the Company of the NYSE MKT's corporate governance listing standards, qualifying the certification to the extent necessary. In accordance with the rules of the NYSE MKT, we last provided such a certification within 30 days after our 2013 annual meeting. The certifications of our Chief Executive Officer and Chief Financial Officer required by Sections 302 and 906 of the Sarbanes-Oxley Act have been included as exhibits to this Annual Report on Form 10-K.

Item 11. Executive Compensation

Effective August 5, 2014, our board of managers retained the executive compensation consulting firm of L&A, based out of Houston, Texas. L&A provided the board's compensation committee with guidance on executive compensation, long-term incentive plan and board of manager fees. The Company also participates annually in the ECI Oil & Gas Compensation Survey.

Summary Compensation Table

The following table sets forth the compensation of our named executive officers (NEOs) for 2014 and 2013:

Name and Principal Position	Year	Salary	Cash Bonus [(a)]	Unit Awards [(b)]	All Other Compensation [(c)]	Total
Stephen R. Brunner	2014	$ 350,097	$ 700,350	$ 2,075,174	$ 11,771	$ 3,137,392
President, Chief Executive Officer,						
and Chief Operating Officer [(d)]	2013	$ 339,900	$ 169,950	$ -	$ 8,842	$ 518,692
Elizabeth A. Crawford	2014	$ 75,083	$ -	$ -	$ 17,707	$ 92,790
Vice President of Land, General Counsel						
and Corporate Secretary [(d)(e)]	2013	$ 210,000	$ 57,750	$ -	$ 10,096	$ 277,846
Charles C. Ward	2014	$ 262,573	$ 393,860	$ 823,890	$ 11,256	$ 1,491,579
Chief Financial Officer, Treasurer and						
Secretary[(d)]	2013	$ 254,925	$ 95,597	$ -	$ 13,722	$ 364,244

(a) The amount in this column reflects each named applicable named executive officer's annual cash incentive bonus earned for 2014 and 2013 performance, as applicable. The annual cash incentive bonuses were determined by our compensation committee based on assessments of both Company and individual performance.

(b) The amount in this column reflects the fair market value of notional units awarded to each named executive officer by the compensation committee. Subject to continued employment, the notional units will be payable in cash or restricted units (if a proposal to convert the Company into a limited partnership is approved by our unitholders along with an amendment and restatement of our Omnibus Incentive Compensation Plan).

(c) The amount in this column reflects the amount of matching contributions made to each named executive officer under our 401k plan and the cost of life insurance equal to the named executive officer's salary for 2014 and 2013.

(d) Our named executive officers are eligible to participate in Company benefit plans such as medical, dental, life, and disability insurance, 401k and flexible spending accounts on the same terms as all our employees.

(e) Ms. Crawford was promoted to an executive officer position in February 2013, but resigned from the Company in April, 2014.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth the outstanding equity awards and their market value using the closing price of our common units on NYSE MKT at December 31, 2014 for our 2014 NEOs:

	Outstanding Equity Awards at December 31, 2014			
Name	Number of Restricted Units Not Vested	Number of Unit-Based Awards Not Vested[a]	Fair Market Value of Units Not Vested	Vesting Dates
Stephen R. Brunner	46,717	256,410	$ 424,378	2015
	-	256,410	358,974	2016
	-	256,411	358,975	2017
	46,717	769,231	$ 1,142,327	
Charles C. Ward	15,575	85,470	$ 141,463	2015
	-	85,470	119,658	2016
	-	85,470	119,658	2017
	15,575	256,410	$ 380,779	

[a] The amount in this column reflects notional units granted to Messrs. Brunner and Ward on December 18, 2014. The notional units will convert on a one-for-one basis into restricted common units of Sanchez Production Partners LP upon unitholder approval of a proposed Sanchez Production Partners LP Long-Term Incentive Plan and the conversion of the Company from a limited liability company into a limited partnership becoming effective. The notional units or restricted units, as applicable, will vest in one-third increments on each December 15, 2015, 2016 and 2017. If the new plan is not approved, or the foregoing two conditions are not otherwise satisfied by the applicable vesting date, the notional units then vesting will be settled in cash at the fair market value of the Company's common units as of such date. Each notional unit carries the right to receive distribution credits when any distributions are made by the Company on its common units, which will be settled in cash when the notional units are converted or settled, as applicable.

Employment Agreements

Pursuant to the terms of the employment agreements, each 2014 NEO received the following compensation with respect to performance for 2014:

Name	Base Salary	Bonus Target	Maximum Bonus
Stephen R. Brunner	$ 350,097	100%	200%
Charles C. Ward	$ 262,573	75%	150%

Termination of Employment

Each executive's employment may be terminated at any time and for any reason by either or both of the Company and the executive. Except as described below, if the executive terminates his or her employment, all unvested or unearned awards will be forfeited. If the executive's employment is terminated in connection with an "Involuntary Termination" at any time prior to a change of control of the Company or after two years have elapsed following a change of control, the Company will, pursuant to the terms of the employment agreements, make payments and take actions as follows (such payments and actions, the Severance Amount):

- make a cash payment of (i) one and one-half times the executive's then-current annual compensation, which includes (A) the target-level bonus plus (B) the greater of the annual base salary in effect on the date of the Involuntary Termination or the annual base salary in effect 180 days prior to the Involuntary Termination;
- cause any unvested awards granted under the 2009 Omnibus Incentive Compensation Plan or the Long-Term Incentive Plan to become immediately vested and cause any and all nonqualified deferred compensation to become immediately nonforfeitable; and
- cause a continuation of medical and dental benefits for one year following the Involuntary Termination.

If the executive's employment is terminated (i) by the executive if a specified person acquires more than 48% of our common units or (ii) in connection with an Involuntary Termination during the two-year period following a Change of Control of the Company, the Company will, pursuant to the terms of his or her Employment Agreement, make payments and take actions as follows (such payments and actions, the “Enhanced Severance Amount”):

- make a cash payment of (i) two times the executive’s then-current annual compensation, which includes (A) the target level bonus plus (B) the greater of the annual base salary in effect on the date of the Involuntary Termination, the annual base salary in effect 180 days prior to the Involuntary Termination, or the annual base salary in effect immediately prior to the change of control, plus (iii) the performance award and target-based grants payable under the Plan for the then-current year, paid as if the target-level performance was achieved for the entire year, prorated based on the number of whole or partial months completed at the time of the Involuntary Termination;
- cause any unvested awards granted under the Plan to become immediately vested and cause any and all nonqualified deferred compensation to become immediately nonforfeitable;
- cause a continuation of medical and dental benefits for one year following the change of control; and
- provide for a full tax gross-up in connection with any excise tax levied on the items described in the preceding three bullets.

A “Change of Control” occurs if any of the following events occur: (i) during a period of 24 consecutive months, all of the Class B managers at the beginning of such period, and any persons nominated by at least two such managers, cease to constitute all of the Class B managers, (ii) during a period of 24 consecutive months, the individuals who constitute our board of managers at the beginning of such period, and any persons nominated by at least two Class B managers, cease to constitute at least a majority of our board of managers, (iii) during a period of 24 consecutive months immediately following a Class A Event (which occurred on both March 12, 2012 and August 9, 2013), at least one Class B manager ceases to serve as a manager, (iv) any person becomes the beneficial owner of 25% or more of the combined voting power of our outstanding units eligible to vote for the election of our board of managers, (v) certain business combinations, unless the Company’s unitholders control more than 60% of the voting power of the surviving entity, no person owns more than 25% of the voting power of the surviving entity and a majority of the members of the board of the surviving entity were managers at the time the agreement approving the business combination was approved by our board of managers, (vi) a plan of liquidation of the Company is approved by the unitholders or (vii) a sale of all or substantially all of the assets of the Company to an acquiror which has more than 40% of its voting power controlled by persons other than the Company’s unitholders.

The Severance Amount and Enhanced Severance Amount are contingent on the execution of a release of any claims the terminated executive may have against us and our affiliates. In addition, any such amounts must be repaid if a final and non-appealable judgment is entered by a court of competent jurisdiction finding that the executive’s conduct in performance of his or her duties under the employment agreement constituted willful misconduct.

The employment agreements currently expire in May 2016 unless sooner terminated in accordance with the employment agreement. If the agreements have not otherwise been terminated 180 days prior to such date, the employment agreements will automatically be extended for an additional one-year period unless either party to such employment agreement delivers written notice 180 days prior to the expiration thereof.

Compensation of Managers

Our board of managers, based on recommendations from our compensation committee and input from L&A approved the following individual non-employee manager annual cash compensation program, effective January 1, 2015:

- $40,000 annual retainer for each manager (payable March 31 of each year);
- the chairman of the audit committee will receive a $15,000 annual retainer, the chairman of the compensation committee will receive a $10,000 annual retainer and the chairman of the nominating and governance committee will receive a $8,500 annual retainer;
- $1,500 fee for each meeting of the board of managers and $1,000 for each substantive committee meeting attended by a member thereof that occurs on a day when there is no board meeting;
- reimbursement of reasonable travel expenses to attend meetings and
- an annual common unit award with a value of $100,000, to be granted as of March 31 of each year.

The following table sets forth a summary of the 2014 non-employee manager compensation:

	Manager Compensation			
Name	Fees Earned or Paid in Cash	Unit Awards	All Other Compensation	Total
Richard H. Bachmann[(a)]	$ 88,462	$ -	$ -	$ 88,462
Alan S. Bigman[(b)]	$ 41,158	$ -	$ -	$ 41,158
Richard S. Langdon	$ 195,380	$ -	$ -	$ 195,380
G. M. Byrd Larberg[(b)]	$ 34,038	$ -	$ -	$ 34,038
Antonio R. Sanchez, III	$ 88,125	$ -	$ -	$ 88,125
John N. Seitz[(a)]	$ 88,462	$ -	$ -	$ 88,462
Gerald F. Willinger	$ 95,625	$ -	$ -	$ 95,625

(a) Messrs. Bachmann and Seitz did not seek re-election.
(b) Messrs. Bigman and Larberg joined the board of managers effective July 14, 2014.

Compensation Risk Assessment

Our compensation committee has a risk assessment process for compensation programs and found no policies or practices that would rise to the level of being reasonably likely to have a material adverse effect on the Company. We believe our compensation programs do not encourage our employees to take excessive risks to achieve larger performance-based bonus awards or additional unit-based compensation above their individual targets.

Compensation Committee Interlocks and Insider Participation

During 2014, none of our named executive officers served as a member of the board of directors or compensation committee of any entity that had one or more of its named executive officers serving as a member of our board of managers or compensation committee.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The following table sets forth the beneficial ownership of our units held by:

- each unitholder who is a beneficial owner of more than 5% of our outstanding units;
- each of our managers and 2014 NEOs; and
- our managers and executive officers as a group.

The amounts and percentage of common units and Class A units beneficially owned are reported on the basis of the SEC rules governing the determination of beneficial ownership of securities. Under the SEC rules, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, and/or "investment power," which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

Percentage of total units beneficially owned is based on 28,792,584 common units and 484,505 Class A units outstanding. Except as indicated by footnote, to our knowledge the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable. Unless otherwise set forth below, the address of all of all beneficial owners is c/o Sanchez Production Partners LLC, 1000 Main Street, Suite 3000, Houston, Texas 77002. Ownership amounts are as of December 31, 2014.

Name of Beneficial Owner	Common Units Beneficially Owned		Class A Units Beneficially Owned		Percentage of Total Units Beneficially Owned
	Number	Percentage	Number	Percentage	
Sanchez Energy Partners I, LP (1)	5,364,196	18.6%	484,505	100%	20.0%
Raging Capital Master Fund, Ltd. (2)	4,163,294	14.5%	-	-	14.2%
Dorsey R. Gardner (3)	2,477,377	8.6%	-	-	8.5%
SP Holdings (4)	59,562	*	-	-	*
Alan S. Bigman	-	-	-	-	-
Stephen R. Brunner	764,937	2.7%	-	-	2.6%
Richard S. Langdon	55,468	*	-	-	*
G.M. Larberg	-	-	-	-	-
Antonio R. Sanchez, III (1)(4)	5,430,161	18.9%	484,505	100%	20.2%
Charles C. Ward	377,394	1.3%	-	-	1.3%
Gerald F. Willinger	6,403	*	-	-	*
All managers and executive officers as a group					
(7 persons)	1,210,605	4.2%	-	-	4.1%

* Less than 1%

(1) 6,403 common units are held directly by Mr. Sanchez. Ownership data for 5,364,196 common units and 484,505 Class A units as reported on Form 13D/A filed on December 24, 2014 by SEP I, SOG, SEP Management I, LLC, Antonio R. Sanchez, Jr. and Antonio R. Sanchez, III. The business address of each filer is 1000 Main Street, Suite 3000, Houston, Texas 77002. These securities are owned directly by SEP I, which is controlled by its general partner, SEP Management I, LLC, a wholly-owned subsidiary of SOG. SOG is managed by Antonio R. Sanchez, Jr., Antonio R. Sanchez, III and other Sanchez family members. Each of SEP Management I, LLC, SOG, Antonio R. Sanchez, Jr. and Antonio R. Sanchez, III may be deemed to share voting and dispositive power over the units held by SEP I. Each of SEP Management I, LLC, SOG, Antonio R. Sanchez, Jr. and Antonio R. Sanchez, III disclaims beneficial ownership of these securities except to the extent of such person's pecuniary interest herein.

(2) Ownership data as reported on Schedule 13G filed on November 10, 2014 by Raging Capital Master Fund, Ltd., Raging Capital Management, LLC and William C. Martin. The principal business address of each of Raging Capital Management, LLC and Mr. Martin is Ten Princeton Avenue, PO Box 228, Rocky Hill, New Jersey 08553; and the principal business address of Raging Capital Master Fund, Ltd. Is c/o Ogier Fiduciary Services (Cayman) Limited, 89 Nexus Way, Camana Bay, Grand Cayman KY 1-9007, Cayman Islands. The filings list each filing person as having shared voting and dispositive power over the units.

(3) Ownership data as reported on Schedule 13G/A filed on February 9, 2015 by Dorsey R. Gardner. The address of Mr. Gardner is 401 Worth Avenue, Palm Beach, Florida 33480. The filing lists Mr. Gardner as having sole voting and dispositive power over the common units held by the DRG 2002 Revocable Trust (2,013,009), the DRG Rollover IRA (64,485), William G. Gardner (25,000), the DRG 2012 Trust (41,400) and the Robert O'Neill Trust (2,900).

(4) 59,562 common units are held by SP Holdings, of which Mr. Sanchez is a co-manager of its sole member.

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, 2014:

Plan Category	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
Equity compensation plans approved by security holders[(a)]	—	$ —	115,763
Equity compensation plans not approved by security holders	—	$ —	—
Total	—	$ —	115,763

(a) As of March 2, 2015, the number of securities remaining available for future issuance under our Long-Term Incentive Plan was 26,990 and the number remaining available under our 2009 Omnibus Incentive Plan was 88,773.

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

SOG, through a subsidiary, owns a portion of our outstanding units. As of December 31, 2014, SEP I, a subsidiary of SOG, owned 484,505, or 100% of our Class A units and 5,364,196, or 18.6%, of our Class B common units.

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 SOG or its related companies, including 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.

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 20% ownership interest in us at December 31, 2014. These units were issued to SEP I, along with cash, in exchange for oil and natural gas properties located in Texas and Louisiana. 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. 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 received in the transaction.

On May 8, 2014, the Company and the Manager, a SOG-related company, 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 rights 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 December 31, 2014, the Company has paid $6.0 million to the Manager under the Services Agreement and issued 59,562 common units to SP Holdings pursuant to the Services Agreement in connection with SP Holdings' election to receive payment of their fee for the quarter ended September 30, 2014 in common units rather than cash. The issuance of the common units was in lieu of paying a fee of $165,582 in cash, or $2.78 per common unit.

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 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. No amounts are payable under the agreement.

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.

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 $1.0 million, or 2% 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. Bigman, Langdon and Larberg 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 for the fiscal years ended December 31, 2013 and 2014.

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 2014 and 2013 were $605,356 and $654,452, respectively.

Tax Fees. There were no tax fees billed by KPMG for the year ended 2014 and 2013. The aggregate fees related to the preparation of K-1 statements and tax services for the year ended 2013 were $338,699, billed by PricewaterhouseCoopers LLP.

All Other Fees. There were no other fees billed by our principal accountant for the years ended 2014 and 2013.

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 5, 2015 of KPMG LLP

Consolidated Statements of Operations—Sanchez Production Partners LLC for the two years ended December 31, 2014

Consolidated Balance Sheets—Sanchez Production Partners LLC at December 31, 2014 and December 31, 2013

Consolidated Statements of Cash Flows—Sanchez Production Partners LLC for the two years ended December 31, 2014

Consolidated Statements of Changes in Members' Equity—Sanchez Production Partners LLC for the two years ended December 31, 2014

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.

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).
2.10	—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).
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).

10.3	—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).
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).
+10.10	—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	—Summary Compensation for Board of Managers.
+10.13	—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).
+10.14	—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).
+10.15	—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).
+10.16	—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).

+10.17	—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).
10.18	—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 Sanchez Production Partners LLC.
*23.1	—Consent of KPMG LLP.
*23.3	—Consent of Netherland, Sewell & Associates, Inc.
*31.1	—Certification of President, Chief Executive Officer and Chief Operating Officer of Sanchez Production Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	—Certification of Chief Financial Officer, Treasurer and Secretary of Sanchez Production Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	—Certification of President, Chief Executive Officer and Chief Operating 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.
*32.2	—Certification of Chief Financial Officer, Treasurer and Secretary 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.
*99.1	—Report of Netherland, Sewell & Associates, Inc.
*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.

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders and Board of Managers of Sanchez Production Partners LLC:

We have audited the accompanying consolidated balance sheets of Sanchez Production Partners LLC (formerly Constellation Energy Partners LLC) and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, changes in members' equity, and cash flows for the years 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 audits.

We conducted our audits 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 audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Sanchez Production Partners LLC and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

/s/KPMG LLP

Houston, Texas
March 5, 2015

SANCHEZ PRODUCTION PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Operations

(In thousands, except per unit data)

	Year Ended December 31, 2014	Year Ended December 31, 2013
Revenues		
Natural gas sales	$ 34,458	$ 23,129
Oil sales	40,337	20,436
Natural gas liquids sales	2,477	512
Total revenues	77,272	44,077
Expenses:		
Operating expenses:		
Lease operating expenses	21,012	18,858
Cost of sales	1,487	1,455
Production taxes	3,200	2,601
General and administrative	16,499	22,214
Loss on sale of assets	223	4
Depreciation, depletion and amortization	17,533	18,972
Asset impairments (See Note 7)	5,424	2,357
Accretion expense	604	519
Total operating expenses	65,982	66,980
Other expense / (income)		
Interest expense	2,076	3,150
Other income	(289)	(196)
Total other expenses	1,787	2,954
Total expenses	67,769	69,934
Income (loss) from continuing operations	9,503	(25,857)
Loss from discontinued operations	-	(2,686)
Net income (loss)	$ 9,503	$ (28,543)
Income (loss) per unit (See Note 1)		
Income (loss) from continuing operations per unit		
Class A units - Basic and diluted	$ 0.25	$ (0.55)
Class B units - Basic and diluted	$ 0.33	$ (1.01)
Discontinued operations per unit		
Class A units - Basic and diluted	$ -	$ (0.06)
Class B units - Basic and diluted	$ -	$ (0.10)
Net income (loss) per unit		
Class A units - Basic and diluted	$ 0.25	$ (0.61)
Class B units - Basic and diluted	$ 0.33	$ (1.11)
Weighted Average Units Outstanding		
Class A units - Basic	763,261	933,613
Class B units - Basic	28,431,586	25,210,106
Class A units - Diluted	763,261	933,613
Class B units - Diluted	28,532,411	25,210,106
Distributions declared and paid per unit	$ —	$ —

See accompanying notes to consolidated financial statements.

SANCHEZ PRODUCTION PARTNERS LLC and SUBSIDIARIES

Consolidated Balance Sheets

(In thousands, except unit data)

		December 31, 2014		December 31, 2013
ASSETS				
Current assets				
Cash and cash equivalents	$	4,238	$	4,894
Restricted cash (See Note 1)		1,748		-
Accounts receivable		5,217		6,678
Prepaid expenses		1,783		2,547
Risk management assets (See Note 5)		14,671		9,141
Total current assets		27,657		23,260
Oil and natural gas properties (See Note 7)				
Oil and natural gas properties, equipment and facilities		651,493		639,156
Material and supplies		1,056		1,054
Less accumulated depreciation, depletion, amortization, and impairments		(517,239)		(495,215)
Net oil and natural gas properties		135,310		144,995
Other assets				
Debt issue costs (net of accumulated amortization of $9,138 and $9,003, respectively)		689		824
Risk management assets (See Note 5)		8,158		1,461
Restricted cash		-		1,748
Other non-current assets		1,790		2,245
Total assets	$	173,604	$	174,533
LIABILITIES AND MEMBERS' EQUITY				
Liabilities				
Current liabilities				
Accounts payable	$	35	$	12
Accrued liabilities		6,081		12,763
Royalty payable		1,134		1,242
Total current liabilities		7,250		14,017
Other liabilities				
Asset retirement obligation		17,031		9,513
Other non-current liabilities		-		1,398
Debt (See Note 6)		42,500		50,700
Total other liabilities		59,531		61,611
Total liabilities		66,781		75,628
Commitments and contingencies (See Note 10)				
Members' equity				
Class A units, 484,505 and 1,615,017 units authorized, issued and outstanding at December 31, 2014 and 2013, respectively		1,930		2,591
Class B units, 28,903,734 and 28,848,785 units authorized, and 28,792,584 and 28,462,185 issued and outstanding at December 31, 2014 and 2013, respectively		104,893		96,314
Total members' equity		106,823		98,905
Total liabilities and members' equity	$	173,604	$	174,533

See accompanying notes to consolidated financial statements.

SANCHEZ PRODUCTION PARTNERS LLC and SUBSIDIARIES
Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31, 2014	Year Ended December 31, 2013
Cash flows from operating activities:		
Net income (loss)	$ 9,503	$ (28,543)
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion and amortization	17,533	18,972
Asset impairments (See Note 7)	5,424	2,357
Amortization of debt issuance costs	271	1,289
Accretion expense	604	519
Equity earnings in affiliate	(216)	(271)
Loss from disposition of property and equipment	223	4
Bad debt expense	94	44
Mark-to-market on derivatives:		
Total gains	(19,855)	1,551
Cash settlements	7,626	12,082
Unit-based compensation programs	1,298	1,049
Discontinued operations	-	2,686
Changes in Assets and Liabilities:		
(Increase) decrease in accounts receivable	1,370	(1,106)
(Increase) decrease in prepaid expenses	764	(1,238)
Decrease in other assets	2	8
Increase (decrease) in accounts payable	23	(468)
Increase (decrease) in accrued and other liabilities	(7,557)	5,383
Decrease in royalty payable	(108)	(176)
Net cash provided by continuing operations	16,999	14,142
Net cash provided by discontinued operations	-	1,062
Net cash provided by operating activities	16,999	15,204
Cash flows from investing activities:		
Cash paid for acquisitions, net of cash acquired	(1,351)	(20,221)
Development of natural gas properties	(5,865)	(15,694)
Proceeds from sale of property and equipment	485	58,987
Increase in cash held for escrow	-	(1,148)
Distributions from equity affiliate	295	245
Net cash provided by (used in) investing activities	(6,436)	22,169
Cash flows from financing activities:		
Proceeds from issuance of debt	5,750	16,894
Repayment of debt	(13,950)	(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)	(953)
Net cash used in financing activities	(11,219)	(34,438)
Net increase (decrease) in cash	(656)	2,935
Cash and cash equivalents, beginning of period	4,894	1,959
Cash and cash equivalents, end of period	$ 4,238	$ 4,894
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ (512)	$ (1,674)
Cash paid during the period for interest	$ (1,841)	$ (1,881)
Cash paid during the period for income taxes	$ (73)	$ (75)

See accompanying notes to consolidated financial statements.

SANCHEZ PRODUCTION PARTNERS LLC and SUBSIDIARIES

Consolidated Statements of Changes in Members' Equity

(In thousands, except unit data)

	Class A		Class B		Accumulated Other Comprehensive Income	Total Members' Equity
	Units	Amount	Units	Amount		
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
Distributions	—	—	—	—	—	—
Units tendered by employees for tax withholding	—	—	(160,182)	(415)	—	(415)
Unit-based compensation programs	—	—	490,581	1,298	—	1,298
Cancellation of units	(1,130,512)	(851)	—	(1,617)	—	(2,468)
Net income	—	190	—	9,313	—	9,503
Balance, December 31, 2014	484,505	$ 1,930	28,792,584	$ 104,893	$ —	$ 106,823

See accompanying notes to consolidated financial statements.

SANCHEZ PRODUCTION PARTNERS LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2014 and 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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 December 31, 2014, Sanchez Energy Partners I, LP (SEP I), a subsidiary of SOG, owned 484,505, or 100%, of our Class A units and 5,364,196, or 18.6%, 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 August 25, 2014, our board of managers approved a plan of conversion providing for the conversion of the Company from a limited liability company organized under the laws of the State of Delaware to a limited partnership organized under the laws of the State of Delaware. Pursuant to the plan of conversion, at the effective time of the conversion, each outstanding common unit of the Company will be converted onto one unit of Sanchez Production Partners LP (Sanchez LP), the outstanding Class A units of the Company will be converted into common units of Sanchez LP in a number equal to 2% of the Sanchez LP common units outstanding immediately after the conversion (after taking into account the conversion of the Class A units) and the outstanding Class Z unit will be cancelled. In addition, a SOG-related company will become the general partner of Sanchez LP, and incentive distribution rights will be issued by Sanchez LP to another SOG-related company. On January 30, 2015, the Company received a Notice of Effectiveness from the SEC regarding its registration statement on Form S-4 with respect to the common units of Sanchez LP to be issued to the Company's common unitholders and the Class A unitholder in connection with the conversion. A special meeting of the Company's unitholders will be held on March 6, 2015 to vote on the plan of conversion and an amendment and restatement of the Constellation Energy Partners LLC 2009 Omnibus Incentive Compensation Plan as the Sanchez Production Partners LP Long-Term Incentive Plan.

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), a SOG-related company, 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

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 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.

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 are included in accounts payable in our consolidated balance sheets. There were no checks-in-transit as of December 31, 2014 and 2013.

Restricted Cash

Restricted cash at December 31, 2014 and 2013 of $1.7 million was 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.

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 $0.2 million during 2014 and less than $0.1 million in 2013. We have no off-balance-sheet credit exposure related to our operations or customers.

For the year ended December 31, 2014, five customers accounted for approximately 33%, 30%, 16%, 14% and 7% of our sales revenues. For the year ended December 31, 2013, five customers accounted for approximately 22%, 20%, 17%, 14% 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.

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.

Oil, Natural Gas and Natural Gas Liquids Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil, natural gas and natural gas liquids 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, 2014 and 2013 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 under the caption “Oil sales” or “Natural gas sales” and settled interest rate swaps as “Interest expense.”

Revenue Recognition

Sales are recognized when oil, natural gas and natural gas liquids have 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 is reasonably assured and the sales price is fixed or determinable. Oil, natural gas and natural gas liquids are generally sold on a monthly basis. Most of the contracts’ pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a specific tank battery, gathering or transmission line, quality of oil, natural gas and natural gas liquids, and prevailing supply and demand conditions, so that the price of the oil, natural gas and natural gas liquids fluctuates to remain competitive with other available oil, natural gas and natural gas liquids supplies. As a result, revenues from the sale of oil, natural gas and natural gas liquids will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our oil, natural gas and natural gas liquids 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 was only a minimal gas imbalance position on one of our wells in the Mid-continent region at December 31, 2014. There were no gas imbalance positions at December 31, 2013.

Income Taxes

SPP 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 our members. As such, no federal income tax for these entities has been provided for in the accompanying financial statements. SPP is subject to franchise tax obligations in Kansas and Texas and state tax obligations in Alabama and Oklahoma. SPP 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, 2014, and 2013, the current and deferred income taxes for the entity were immaterial. The entity has no material deferred tax assets or liabilities.

Earnings per Unit

Basic earnings per unit (EPU) is computed from the two-class method 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, 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 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,	
	2014	2013
Weighted average units outstanding during period:		
Class A units - Basic	763,261	933,613
Class B Common units - Basic	28,431,586	25,210,106
	29,194,847	26,143,719
Weighted average units outstanding during period:		
Class A units - Diluted	763,261	933,613
Class B Common units - Diluted	28,532,411	25,210,106
	29,295,672	26,143,719

At December 31, 2014, we had 100,825 Class B common units that were restricted unvested common units granted and outstanding. These units were included in the diluted weighted average common units outstanding number since we recognized net income for the period. 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 units outstanding number since we recognized a net loss for the year.

The following table presents our basic and diluted income per unit for the year ended December 31, 2014 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Income from continuing operations	$ 9,503		
Distributions	-	$ -	$ -
Assumed allocation of income from continuing operations	9,503	190	9,313
Discontinued operations	-	-	-
Assumed net income to be allocated	$ 9,503	$ 190	$ 9,313
Basic and diluted income from continuing operations per unit		$ 0.25	$ 0.33
Basic and diluted income from discontinued operations per unit		$ -	$ -
Basic and diluted income per unit		$ 0.25	$ 0.33

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)	(53)	(2,633)
Assumed net loss to be allocated	$ (28,543)	$ (570)	$ (27,973)
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)

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. At December 31, 2014, we had no environmental liabilities recorded, as no liabilities were deemed necessary.

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.

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 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 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 will not be material.

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 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. The adoption of this guidance will have no material impact on our financial position, results of operations or cash flows.

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 year ending December 31, 2013 (in thousands):

	Year Ended December 31, 2013	
Revenues	$	2,304
Loss from discontinued operations	$	(2,686)

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.

There were no major classes of assets and liabilities components of discontinued operations at December 31, 2013.

There were no significant divestitures of oil and natural gas properties during the year ended December 31, 2014.

3. ACQUISITIONS

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 and 4,724,407 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 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 allocation of the purchase price 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.

The following table summarizes the 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 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):

	Twelve Months Ended December 31,	
	2013	
Revenue	$	15,782
Lease Operating Expenses	$	3,047

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.

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.

		Pro Forma Twelve Months Ended December 31,
(In thousands)		2013
Revenue	$	56,841
Income (loss) from continuing operations	$	(18,514)
Discontinued operations	$	(2,686)
Net Loss	$	(21,200)
Income (loss) from continuing operations per unit		
Class A units - Basic and diluted	$	(0.23)
Class B units - Basic and diluted	$	(0.65)
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	$	(0.26)
Class B units - Basic and diluted	$	(0.74)
Weighted average units outstanding		
Class A units - Basic and diluted		1,615,103
Class B units - Basic and diluted		28,057,592

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. The 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.

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 December 31, 2014 (in thousands):

	Fair Value Measurements at December 31, 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 December 31, 2014**
Risk Mgmt Assets	$ —	$ 22,919	$ —	$ (90)	$ 22,829
Risk Mgmt Liabilities	—	(90)	—	90	—
Total Net Assets and Liabilities	$ —	$ 22,829	$ —	$ —	$ 22,829

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

As of December 31, 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 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.

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, 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
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
									8,310,181	

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
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
									473,800	

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, 2014	Fair Value of Asset/(Liability) On Balance Sheet December 31, 2013
Commodity – MTM	Risk management assets - current	$ 14,698	$ 10,043
Commodity – MTM	Risk management assets - non-current	8,221	1,534
	Total gross assets	22,919	11,577
Commodity – MTM	Risk management assets – current	(27)	(903)
Commodity – MTM	Risk management assets – non-current	(63)	(72)
	Total gross liabilities	(90)	(975)
	Total net assets and liabilities	$ 22,829	$ 10,602

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, 2014		2013	
Commodity – MTM	Oil and natural gas sales	$	19,854	$	(1,486)
Interest Rate – MTM	Interest expense		-		(65)
	Total	$	19,854	$	(1,551)

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, 2014 and 2013, the impact of non-performance credit risk on the valuation of our net assets from counterparties was not significant

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. 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 December 31, 2014, we had borrowed $42.5 million under our reserve-based credit facility and our borrowing base was $70.0 million. At December 31, 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 December 31, 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 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 (a) any person or two or more persons acting as a group acquiring beneficial ownership of 35% or more of the outstanding shares of voting stock of the Company or (b) individuals who constitute the current Class B managers of the Company's current board of managers cease for any reason to constitute at least a majority of the Company's board of managers; provided however, that any individual becoming a Class B manager whose election, or nomination for election by the Company's unitholders, was approved by a vote of at least a majority of the Class B managers then comprising the current board, shall be considered as though such person was a Class B manager of the current board of managers, but excluding any such person whose initial assumption of office occurs as a result of either an actual or threatened election contest or other actual or threatened solicitation of proxies or consents by or on behalf of a person other than the Company's board of managers. Neither of these events have occurred, so no change in control had occurred as of December 31, 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 and the payment of fees and expenses. As of December 31, 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, nor to the Services Agreement between us and SP Holding, LLC, a SOG-related company.

Compliance with Financial Covenants

At December 31, 2014, 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, 2014, our actual Total Net Debt to annual Adjusted EBITDA ratio was 1.6 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 5.6 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 13.3 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, 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 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, 2014, we had $42.5 million in outstanding debt under our reserve-based credit facility and $27.5 million in remaining borrowing capacity. At December 31, 2013, we had $50.7 million in outstanding debt under our reserve-based credit facility.

Debt Issue Costs

As of December 31, 2014, our unamortized debt issue costs were approximately $0.7 million. These costs are being amortized over the life of the credit facility. At December 31, 2013, our unamortized debt issue costs were approximately $0.8 million.

7. OIL AND NATURAL GAS PROPERTIES

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

	December 31,	
	2014	2013
Oil and natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 649,432	$ 636,816
Unproved property	1,560	1,589
Total property costs	650,992	638,405
Materials and supplies	1,056	1,054
Land	501	751
Total	652,549	640,210
Less: Accumulated depreciation, depletion, amortization and impairments	(517,239)	(495,215)
Oil and natural gas properties and equipment, net	$ 135,310	$ 144,995

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

	Year Ended December 31,	
	2014	2013
DD&A of oil and natural gas-related assets	$ 17,533	$ 18,972
Asset impairments	5,424	2,357
Total	$ 22,957	$ 21,329

Impairment Charges

Our non-cash asset impairment charges for the year ended December 31, 2014 were $5.4 million, compared to $2.3 million for the same period in 2013. Our non-cash impairment charges in 2014 were approximately $5.4 million to impair the value of our oil and natural gas fields in Texas and Louisiana due to the decrease in oil prices.

Our non-cash impairment charges in 2013 were approximately $2.2 million to impair the value of our oil and natural gas fields in Texas and Louisiana and $0.1 million to impair certain of our wells in the Woodford Shale due to decreases in natural gas prices.

Asset Sales

In 2014, we sold miscellaneous furniture and fixtures, trucks and equipment resulting in a loss on sale of $0.2 million.

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 years ended December 31, 2014 and 2013. 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 SPP participate in an employment savings plan. Matching contributions made by us were approximately $0.2 million and $0.3 million for the years ended December 31, 2014 and 2013, respectively.

9. RELATED PARTY TRANSACTIONS

Unit Ownership

SOG, through a subsidiary, owns a portion of our outstanding units. As of December 31, 2014, SEP I, a subsidiary of SOG, owned 484,505, or 100%, of our Class A units and 5,364,196, or 18.6%, of our Class B common units.

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 20% ownership interest in us at December 31, 2014. These units were issued to SEP I, along with cash, in exchange for oil and natural gas properties located in Texas and Louisiana. 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. 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 received in the transaction.

On May 8, 2014, the Company and the Manager, a SOG-related company, 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 rights 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 December 31, 2014, the Company has paid $6.0 million to the Manager under the Services Agreement and issued 59,562 common units to SP Holdings pursuant to the Services Agreement in connection with SP Holdings' election to receive payment of their fee for the quarter ended September 30, 2014 in common units rather than cash. The issuance of the common units was in lieu of paying a fee of $165,582 in cash, or $2.78 per common unit.

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 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. No amounts are payable under the agreement.

Class Z Unit

SEP I holds the one Class Z unit of SPP. 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

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.

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 Constellation Energy Partners Holdings, LLC (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.

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.

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

	December 31,			
	2014		2013	
Asset retirement obligation, beginning balance	$	9,513	$	7,665
Liabilities added from acquisitions		80		1,088
Liabilities added from drilling		59		244
Revisions to cost estimates		6,780		-
Settlements		(5)		(3)
Accretion expense		604		519
Asset retirement obligation, ending balance	$	17,031	$	9,513

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 2014 and 2013, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing asset retirement obligations. During the year ended December 31, 2014, revisions were made to the ARO liability based on recent costs incurred on abandoned wells, which were higher than originally projected.

12. UNIT-BASED COMPENSATION

We have the following unit-based compensation plans:

We have the 2009 Omnibus Incentive Compensation Plan (Omnibus Plan), which 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, 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
Vested	(450,958)		2.80
Granted	346,403		2.44
Returned/Cancelled	(151,842)		2.86
Outstanding at December 31, 2014	80,154	$	3.18

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

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, 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
Vested	(99,381)	2.51
Granted	103,278	2.44
Returned/Cancelled	(27,002)	2.57
Outstanding at December 31, 2014	20,671	$ 2.83

We recognized approximately $1.3 million and $1.0 million of non-cash compensation expense related to our unit-based compensation plans in the twelve months ended December 31, 2014 and 2013, respectively. As of December 31, 2014, we had approximately $0.1 million in unrecognized compensation expense related to our unit-based compensation plans expected to be recognized through the first quarter of 2015.

On December 18, 2014, the compensation committee of our board of managers awarded notional units under the Omnibus Plan to each of our executive officers. The notional amounts awarded were 769,231 units to our Chief Executive Officer and 256,410 units to our Chief Financial Officer. The notional units will convert on a one-for-one basis into restricted common units of Sanchez Production Partners LP upon unitholder approval of a proposed Sanchez Production Partners LP Long-Term Incentive Plan and the conversion of the Company from a limited liability company into a limited partnership becoming effective. The notional units or restricted units, as applicable, will vest in one-third increments on each December 15, 2015, 2016 and 2017. If the new plan is not approved, or the foregoing two conditions are not otherwise satisfied by the applicable vesting date, then the notional units then vesting will be settled in cash at the fair market value of the Company's common units as of such date. Each notional unit carries the right to receive distribution credits when any distributions are made by the Company on its common units, which will be settled in cash when the notional units are converted or settled, as applicable. This award was classified as a liability-classified award as of and for the year ended December 31, 2014. As a liability-classified award, the fair value of the award is re-measured at each financial statement date until the award is settled or expires. During the requisite service period, compensation cost is recognized using the proportionate amount of the award's fair value that has been earned through service to date.

13. DISTRIBUTIONS TO UNITHOLDERS

Beginning in June 2009, we suspended our quarterly distributions to unitholders. For twelve months ended December 31, 2014 and 2013, 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

2014 Equity

At December 31, 2014, we had 484,505 Class A units and 28,792,584 Class B common units outstanding, which included 20,671 unvested restricted common units issued under our L-TIP and 80,154 unvested restricted common units issued under our Omnibus Plan.

At December 31, 2014, we had granted 423,010 common units of the 450,000 common units available under our L-TIP. Of these grants, 402,339 have vested.

At December 31, 2014, we had granted 1,561,227 common units of the 1,650,000 common units available under our Omnibus Plan. Of these grants, 1,481,073 have vested.

For the year ended December 31, 2014, 160,182 common units were tendered by our employees for minimum tax withholding purposes. These units, costing approximately $0.4 million, have been 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 and 336,551 unvested restricted common units issued under our Omnibus Plan.

At December 31, 2013, we had granted 346,734 common units of the 450,000 common units available under our L-TIP. 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 year ended December 31, 2013, 139,810 common units were tendered by our employees for minimum tax withholding purposes. These units, costing approximately $0.2 million, have been 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.

Costs

The following table sets forth capitalized costs for the years ended December 31, 2014 and 2013 (in thousands):

	December 31,	
	2014	2013
Capitalized costs at the end of the period:[(a)]		
Oil and natrual gas properties and related equipment (successful efforts method)		
Property costs		
Proved property	$ 649,432	$ 636,816
Unproved property	1,560	1,589
Total property costs	650,992	638,405
Materials and supplies	1,056	1,054
Land	501	751
Total	652,549	640,210
Less: Accumulated depreciation, depletion, amortization and impairments	(517,239)	(495,215)
Oil and natural gas properties and equipment, net	$ 135,310	$ 144,995

(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.

The following table sets forth costs incurred for oil and natural gas producing activities for the years ended December 31, 2014 and 2013 (in thousands):

	For the year ended December 31,	
	2014	2013
Costs incurred for the period:		
Acquisition of properties		
Proved	$ 1,239	$ 20,012
Unproved	112	209
Development costs	5,865	15,694
Oil and natural gas properties and equipment, net	$ 7,216	$ 35,915

The development costs for the years ended December 31, 2014 and 2013 primarily represent costs to develop our proved undeveloped reserves. The properties acquired in 2014 and 2013 were in Texas and Louisiana.

We had no exploration and dry hole costs in 2014 and 2013, 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. All of our operations are oil and natural gas producing activities located in the United States.

Net Proved Oil, Natural Gas and Natural Gas Liquids 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.

	Total (Mmcfe)	Oil (in Mmcfe)	Natural Gas (in Mmcfe)	Natural Gas Liquids (in Mmcfe)
Net proved reserves				
December 31, 2012	92,982	6,503	-	86,479
Extensions and discoveries	4,825	4,016	128	681
Puchase of reserves in place	7,150	1,668	523	4,959
Sales of reserves in place	(49,385)	-	-	(49,385)
Revisions of previous estimates	44,727	1,147	207	43,373
Production	(9,045)	(901)	-	(8,144)
December 31, 2013	91,254	12,433	858	77,963
Extensions and discoveries	3,052	2,493	-	559
Puchase of reserves in place	437	437	-	-
Revisions of previous estimates	14,163	(3,542)	(340)	18,045
Production	(9,143)	(1,849)	(169)	(7,125)
December 31, 2014	99,763	9,972	349	89,442
Proved developed reserves:				
December 31, 2013	78,629	11,170	858	66,601
December 31, 2014	74,634	9,139	349	65,146
Proved undeveloped reserves:				
December 31, 2013	12,625	1,264	-	11,361
December 31, 2014	25,129	833	-	24,296

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, 2014 and 2013 proved reserve estimates were 99.8 Bcfe and 91.3 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 2014 estimates of total proved reserves increased 8.5 Bcfe from 2013 due to a 12.9 Bcfe increase in undeveloped gas reserves in the Cherokee Basin. The higher volumes were due to a higher gas price. Our reserves are 90% 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: $93.95 per barrel for oil, $35.11 per barrel for natural gas liquids and $4.09 per Mcf for natural gas. Proved developed producing reserves were lower due to natural production decline.

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 were primarily the result of higher natural gas prices. Our reserves were 85% natural gas and were 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 were classified as probable or possible reserves to the extent they were 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 SPP 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 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,	
	2014	**2013**
Future cash inflows	$ 532,152	$ 502,831
Future production costs	(260,909)	(227,315)
Future estimated development costs	(57,741)	(40,694)
Future net cash flows	213,502	234,822
10% annual discount for estimated timing of cash flows	(93,969)	(91,108)
Standardized measure of discounted estimated future net cash flows related to proved gas reserves	$ 119,533	$ 143,714

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,	
	2014	2013
Beginning of the period	$ 143,714	$ 89,669
Sales and transfers of oil and natural gas, net of production costs	(38,817)	(21,244)
Net changes in prices and production costs related to future production	(18,410)	50,425
Development costs incurred during the period	18,075	5,615
Changes in extensions and discoveries	24,611	28,494
Revisions of previous quantity estimates	(22,034)	21,455
Purchases and sales of reserves in place	1,918	(2,297)
Accretion discount	14,371	8,967
Other	(3,895)	(37,370)
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 119,533	$ 143,714

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 PROUDUCTION PARTNERS LLC
(REGISTRANT)

Date: March 5, 2015

By /S/ STEPHEN R. BRUNNER
Stephen R. Brunner
President, Chief Executive Officer
and Chief Operating Officer

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

	Signature	Title	Date
Principal executive officer:			
By	/S/ STEPHEN R. BRUNNER **Stephen R. Brunner**	President, Chief Executive Officer, and Chief Operating Officer	March 5, 2015
Principal financial officer and principal accounting officer:			
By	/S/ CHARLES C. WARD **Charles C. Ward**	Chief Financial Officer, Treasurer and Secretary	March 5, 2015
Managers:			
	/S/ ALAN S. BIGMAN **Alan S. Bigman**	Manager	March 5, 2015
	/S/ RICHARD S. LANGDON **Richard S. Langdon**	Manager	March 5, 2015
	/S/ G.M. BYRD LARBERG **G. M. Byrd Larberg**	Manager	March 5, 2015
	/S/ ANTONIO R. SANCHEZ III **Antonio R. Sanchez III**	Manager	March 5, 2015
	/S/ GERALD F. WILLINGER **Gerald F. Willinger**	Manager	March 5, 2015

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).
2.10	—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).
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).
10.3	—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).
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).
+10.10	—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	—Summary Compensation for Board of Managers.
+10.13	—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).
+10.14	—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).
+10.15	—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).
+10.16	—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).
+10.17	—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).
10.18	—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 Sanchez Production Partners LLC.
*23.1	—Consent of KPMG LLP.
*23.3	—Consent of Netherland, Sewell & Associates, Inc.
*31.1	—Certification of President, Chief Executive Officer and Chief Operating Officer of Sanchez Production Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	—Certification of Chief Financial Officer, Treasurer and Secretary of Sanchez Production Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	—Certification of President, Chief Executive Officer and Chief Operating 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.
*32.2	—Certification of Chief Financial Officer, Treasurer and Secretary 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.
*99.1	—Report of Netherland, Sewell & Associates, Inc.
*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

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* Filed herewith

\+ Management contract or compensatory plan or arrangement.

Board/Committee Compensation

Type of Compensation	Amount
Annual Board Cash Retainer	$40,000 (payable March 31 of each year)
Annual Equity Grant	$100,000 (issued March 31 of each year based on the trading price on such date (or the next trading day if such date is not a trading day); fully vested upon issuance)
Board Meeting Fees	$1,500 for each meeting
Committee Meeting Fees	$1,000 for each substantive meeting of each committee of the Board
Annual Committee Chair Retainer	$15,000 for Audit Committee Chair
	$10,000 for Compensation Committee Chair
	$8,500 for Nominating and Corporate Governance Committee Chair

Subsidiaries of
Sanchez Production Partners LLC

	Jurisdiction of Organization
CEP Mid-Continent LLC	Delaware
CEP Services Company, Inc.	Delaware
Northeast Shelf Energy, L.L.C.	Oklahoma
Mid-Continent Oilfield Supply, L.L.C.	Oklahoma
SEP Holdings IV, LLC	Delaware

* The names of certain indirectly owned subsidiaries have been omitted because, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary pursuant to Rule 1-02(W) of Regulation S-X.

KPMG LLP
811 Main Street
Houston, TX 77002

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Unitholders and Board of Managers of Sanchez Production Partners LLC:

We consent to the incorporation by reference in the registration statements on Form S-4 (No. 333-198440), Form S-8 (No. 333-140745, and Form S-8 (No. 333-163426) of Sanchez Production Partners LLC (formerly Constellation Energy Partners LLC) of our report dated March 5, 2015, with respect to the consolidated balance sheets of Sanchez Production Partners LLC as of December 31, 2014 and 2013, and the related consolidated statements of operations, changes in members' equity, and cash flows for the years then ended, which report appears in the December 31, 2014 annual report on Form 10-K of Sanchez Production Partners LLC.

/s/ KPMG LLP
KPMG LLP

Houston, Texas
March 5, 2015

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

March 5, 2015

Mr. Richard M. Miller
Sanchez Production Partners LLC
1000 Main Street, Suite 3000
Houston, Texas 77008

Dear Mr. Miller:

In accordance with your request, we have enclosed our Consent of Independent Petroleum Engineers and Geologists for the Form 10-K Registration Statement to be filed by Sanchez Production Partners LLC with the U.S. Securities and Exchange Commission.

Our Consent is based on our review of the draft provided to us on March 4, 2015, and is conditioned upon there being no further changes made that relate to us in the Form 10-K. In the event your subsequent filings include further changes relating to our reserves estimates or our firm, we would like to review such changes and provide a new Consent letter.

Please send us a copy of the final Form 10-K when filed with the U.S. Securities and Exchange Commission. Please let us know if we can be of further assistance.

Sincerely,

/s/ Danny D. Simmons

Danny D. Simmons, P.E.
President and Chief Operating Officer

RBT:MGH

Enclosures

Exhibit 31.1

SANCHEZ PRODUCTION PARTNERS LLC
CERTIFICATION

I, Stephen R. Brunner, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sanchez Production Partners LLC;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 5, 2015

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

Exhibit 31.2

SANCHEZ PRODUCTION PARTNERS LLC
CERTIFICATION

I, Charles C. Ward, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sanchez Production Partners LLC;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 5, 2015

/s/ Charles C. Ward
Charles C. Ward
Chief Financial Officer, Treasurer and Secretary

Exhibit 32.1

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

I, Stephen R. Brunner, President, Chief Executive Officer and Chief Operating Officer of Sanchez Production Partners LLC, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2014 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

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

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

Date: March 5, 2015

Exhibit 32.2

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

I, Charles C. Ward, Chief Financial Officer, Treasurer and Secretary of Sanchez Production Partners LLC, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2014 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

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

/s/ Charles C. Ward
Charles C. Ward
Chief Financial Officer, Treasurer and Secretary

Date: March 5, 2015

February 3, 2015 Exhibit 99.1

Mr. Richard M. Miller
Sanchez Production Partners LLC
1000 Main Street, Suite 3000
Houston, Texas 77002

Dear Mr. Miller:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2014, to the Sanchez Production Partners LLC (Sanchez) interest in certain oil and gas properties located in Kansas, Louisiana, Oklahoma, and Texas. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Sanchez. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Sanchez's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Sanchez interest in these properties, as of December 31, 2014, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	1,435.1	43.6	29,754.4	150,766.9	103,167.3
Proved Developed Non-Producing	88.1	14.6	35,391.7	46,469.2	14,982.8
Proved Undeveloped(1)	138.8	0.0	24,296.2	16,265.2	1,382.6
Total Proved	1,662.0	58.2	89,442.2	213,501.3	119,532.6

Totals may not add because of rounding.

(1) These reserves have been included based on the operators' declared intent to drill these wells.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. Estimates of proved undeveloped reserves have been included for certain locations that generate positive future net revenue but have negative present worth discounted at 10 percent based on the constant prices and costs discussed in subsequent paragraphs of this letter. These locations have been included based on the operators' declared intent to drill these wells, as evidenced by Sanchez's internal budget, reserves estimates, and price forecast. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Sanchez's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Sanchez's share of production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2014. For oil and NGL volumes, the average regional posted or spot prices are adjusted for quality, transportation fees, and market differentials. For gas volumes, the average regional spot prices are adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $93.95 per barrel of oil, $35.11 per barrel of NGL, and $4.090 per MCF of gas.

Operating costs used in this report are based on operating expense records of Sanchez. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Sanchez are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Sanchez and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Sanchez interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Sanchez receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Sanchez, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for non-producing zones; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Sanchez, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Richard B. Talley, Jr., a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. David E. Nice, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 13 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E. 102425
Vice President

By: /s/ David E. Nice
David E. Nice. P.G. 346
Vice President

Date Signed: February 3, 2015

WKB:MGH

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90%

probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);
- The company's historical record at completing development of comparable long-term projects;
- The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;
- The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and
- The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.