BREITBURN
ENERGY PARTNERS LP®

2015 ANNUAL REPORT
NOTICE OF 2016 ANNUAL MEETING OF LIMITED PARTNERS
PROXY STATEMENT

TO OUR FELLOW UNITHOLDERS

Breitburn recently completed its first full year of operations after acquiring QR Energy, and I'm pleased to report that the combination has been very successful. This acquisition, which was the largest in our history, significantly expanded our quality portfolio of long-lived, low-decline assets.

After closing the transaction, we committed ourselves to living within our cash flow by cutting costs throughout our organization and reducing debt, and we met our goals despite the extended downturn in commodity prices currently affecting the oil and gas industry. We generated Adjusted EBITDA of approximately $637 million last year based in part on the following:

- Total production was 20.2 million barrels of oil equivalent (Boe), which was at the high-end of our forecasts;
- Our lease operating expenses (before taxes) were $17.74/Boe in the fourth quarter of 2015, more than 18% lower than the prior fourth quarter; and
- Our G&A expenses (excluding acquisition and integration costs and non-cash unit based compensation) were $3.02/Boe for the year, 13% lower than 2014, and were $2.48/Boe in the fourth quarter, our best quarter ever.

Turning to our financial results, we focused on conserving capital and reducing bank borrowings. In 2015, we reduced our capital budget by more than 60% to $200 million, in light of declining commodity prices; in 2016, we reduced our capital budget by an additional 60% to approximately $80 million, in light of the extended downturn in commodity prices. Putting this in perspective, our 2016 capital program is just 15% of the combined Breitburn and QR Energy capital budgets from 2014. Despite this significantly lower capital budget, we still expect to produce approximately 18.4 million Boe in 2016. We can keep a healthy production profile even with our reduced capital program due to our low-decline properties and our deep inventory of quality projects that we acquired over the years. This allows us to high-grade our capital program by choosing only the strongest economic projects – those that make sense even in the current environment.

Anticipating that this lower price environment would be longer, Breitburn was one of the first domestic E&P companies – and ultimately one of the few – to complete a large capital raise last year. In April, we successfully closed a $1 billion strategic investment from EIG Global Energy Partners – an experienced investor in the energy space. In addition, we lowered and ultimately suspended the distribution on our common units last year. While this was a difficult decision, it will allow us to save approximately $450 million this year as a result. Between our capital raising efforts last April and our successful efforts in cutting costs throughout our entire organization, we were able to reduce our outstanding borrowings on our credit facility by nearly $1 billion last year.

In addition, Breitburn has one of the more robust hedge portfolios in the E&P sector – 77% of our 2016 production is hedged at very attractive prices for oil and gas. Our hedge portfolio will provide excellent visibility around our cash flow again, this year and next. As of the end of last year, the estimated fair value of our commodity hedge portfolio was approximately $666 million.

Part of our quality portfolio includes an attractive undeveloped position in the Midland Basin – more than 20,000 net acres in Howard and Martin counties with more than 350 net horizontal locations in the Lower Sprayberry and Wolfcamp A and B zones alone. This valuable asset is core to our future growth, particularly because of its low-cost, high-return production profile.

With an experienced team in place and our high-quality assets, we believe that Breitburn is well-positioned to execute our operating plan successfully again in 2016 despite the extended downturn affecting the oil and gas industry, and we remain ready to adapt to market conditions as they change and evolve throughout the coming year. I want to thank all of our employees for their hard work and unitholders for your continued support.

Sincerely,

HALBERT S. WASHBURN
CEO and Director

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2015

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 001-33055

Breitburn Energy Partners LP
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**74-3169953**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*
707 Wilshire Boulevard, Suite 4600 **Los Angeles, California**	**90017**
(Address of Principal Executive Offices)	*(Zip Code)*

Registrant's telephone number, including area code: (213) 225-5900

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	The NASDAQ Stock Market 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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.

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 Act). Yes ☐ No ☒

The aggregate market value of the Common Units held by non-affiliates was approximately $1.0 billion on June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, based on $4.76 per unit, the last reported sales price on The NASDAQ Global Select Market on such date.

As of February 25, 2016, there were 213,670,116 Common Units outstanding.

Documents Incorporated By Reference: Certain information called for in Items 10, 11, 12, 13 and 14 of Part III of this report are incorporated by reference from the registrant's definitive proxy statement for the 2016 annual meeting of unitholders to be held on April 28, 2016.

BREITBURN ENERGY PARTNERS LP AND SUBSIDIARIES
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GLOSSARY OF OIL AND GAS TERMS; DESCRIPTION OF REFERENCES

The following is a description of the meanings of some of the oil and gas industry terms that may be used in this report. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(6), (22) and (31) of Regulation S-X.

API: The specific gravity or density of oil expressed in terms of a scale devised by the American Petroleum Institute.

ASC: Accounting Standards Codification.

Bbl: One stock tank barrel, or 42 U.S. gallons of liquid volume, of oil or other liquid hydrocarbons.

Bbl/d: Bbl per day.

Bcf: One billion cubic feet of natural gas.

Bcfe: One billion cubic feet equivalent, determined using the ratio of one Bbl of oil to six Mcf of natural gas.

Boe: One barrel of oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a barrel of oil equivalent for natural gas is significantly less than the price for a barrel of oil.

Boe/d: Boe per day.

Btu: British thermal unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

CO_2: Carbon dioxide.

CO_2 Flooding: A tertiary recovery method whereby carbon dioxide is injected into a reservoir to enhance hydrocarbon recovery.

completion: The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

deterministic method: The method of estimating revenues using a single value for each parameter (from the geoscience engineering economic data) in reserves calculations.

development well: A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

differential: The difference between a benchmark price of oil and natural gas, such as the WTI spot oil price, and the wellhead price received.

dry hole or ***well:*** A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

economically producible: A resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

exploitation: A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

exploratory well: 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 not a development well.

FASB: Financial Accounting Standards Board.

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.

gross acres or ***gross wells:*** The total acres or wells, as the case may be, in which a working interest is owned.

ICE: Intercontinental Exchange.

LIBOR: London Interbank Offered Rate.

MBbls: One thousand barrels of oil or other liquid hydrocarbons.

MBoe: One thousand barrels of oil equivalent.

MBoe/d: One thousand barrels of oil equivalent per day.

Mcf: One thousand cubic feet of natural gas.

Mcf/d: One thousand cubic feet of natural gas per day.

Mcfe: One thousand cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil to six Mcf of natural gas.

MichCon: Michigan Consolidated Gas Company.

MMBbls: One million barrels of oil or other liquid hydrocarbons.

MMBoe: One million barrels of oil equivalent.

MMBtu: One million British thermal units.

MMBtu/d: One million British thermal units per day.

MMcf: One million cubic feet of natural gas.

MMcfe: One million cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil to six Mcf of natural gas.

MMcfe/d: One million cubic feet of natural gas equivalent per day, determined using the ratio of one Bbl of oil to six Mcf of natural gas.

net acres or ***net wells:*** The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NGLs: The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX: New York Mercantile Exchange.

oil: Crude oil and condensate.

productive well: A well that is producing or that is mechanically capable of production.

proved developed reserves: Proved reserves that can be expected to be recovered (i) through existing wells with existing equipment or 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. This definition of proved developed reserves has been abbreviated from the applicable definition contained in Rule 4-10(a)(6) of Regulation S-X.

proved reserves: The estimated quantities of oil, NGLs and natural gas that geological and engineering data demonstrate with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods and government regulations. 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. This definition of proved reserves has been abbreviated from the applicable definition contained in Rule 4-10(a)(22) of Regulation S-X.

proved undeveloped reserves or ***PUDs:*** Proved reserves 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. This definition of proved undeveloped reserves has been abbreviated from the applicable definitions contained in Rule 4-10(a)(31) of Regulation S-X.

recompletion: The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

reserve: Estimated remaining quantities of mineral deposits anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

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

spacing: The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.

standardized measure: The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Standardized measure does not give effect to derivative transactions.

undeveloped acreage: Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

US GAAP: Generally accepted accounting principles in the United States.

West Texas Intermediate ("WTI"): Light, sweet oil with high API gravity and low sulfur content used as the benchmark for U.S. crude oil refining and trading. WTI is deliverable at Cushing, Oklahoma to fill NYMEX futures contracts for light, sweet crude oil.

working interest: The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.

workover: Operations on a producing well to restore or increase production.

References in this report to "the Partnership," "we," "our," "us" or like terms refer to Breitburn Energy Partners LP and its subsidiaries. References in this filing to "PCEC" or the "Predecessor" refer to Pacific Coast Energy Company LP, formerly named Breitburn Energy Company LP, our predecessor, and its predecessors and subsidiaries. References in this filing to "Breitburn GP" or the "General Partner" refer to Breitburn GP LLC, our general partner and our wholly-owned subsidiary. References in this filing to The Strand Energy Company refer to a corporation owned by Randall Breitenbach, a member of the Board of Directors of our General Partner, and Halbert Washburn, the Chief Executive Officer and a member of the Board of Directors of our General Partner. References in this filing to "Breitburn Management" refer to Breitburn Management Company LLC, our administrative manager and wholly-owned subsidiary. References in this filing to "BOLP" or "Breitburn Operating" refer to Breitburn Operating LP, our wholly-owned operating subsidiary. References in this filing to "BOGP" refer to Breitburn Operating GP LLC, the general partner of BOLP. References in this filing to "Breitburn Finance" refer to Breitburn Finance Corporation, our wholly-owned subsidiary, incorporated on June 1, 2009. References in this filing to "Breitburn Utica" refer to Breitburn Collingwood Utica LLC, our wholly-owned subsidiary formed September 17, 2010.

PART I

Cautionary Statement Regarding Forward-Looking Information

Certain statements and information in this Annual Report on Form 10-K ("this report") may constitute "forward-looking statements." The words "believe," "expect," "anticipate," "plan," "intend," "future," "projected," "goal," "should," "could," "would" or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, those described in (1) Part I—Item 1A"—Risk Factors" and elsewhere in this report, and (2) our Quarterly Reports on Form 10-Q and Current Reports on Form 8-K filed with the Securities and Exchange Commission (the "SEC").

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

Item 1. Business.

Overview

We are an independent oil and gas partnership focused on the acquisition, exploitation and development of oil, NGL and natural gas properties in the United States. Our objective is to manage our oil, NGL and natural gas producing properties for the purpose of generating cash flow and making distributions to our unitholders. Our assets consist primarily of producing and non-producing oil, NGL and natural gas reserves located in seven producing areas:

- Midwest (Michigan, Indiana and Kentucky);
- Ark-La-Tex (Arkansas, Louisiana and East Texas);
- Permian Basin in Texas and New Mexico;
- Mid-Continent (Oklahoma, Kansas and the Texas Panhandle);
- Rockies (Wyoming and Colorado);
- Southeast (Florida and Alabama); and
- California.

Our assets are characterized by stable, long-lived production and proved reserve life indexes averaging greater than 15 years. As of December 31, 2015, our total estimated proved reserves were 239.3 MMBoe, of which approximately 54% was oil, 8% was NGLs and 38% was natural gas. Our production in 2015 was 20,180 MMBoe, of which approximately 56% was oil, 9% was NGLs and 35% was natural gas.

We are a Delaware limited partnership formed in 2006 and have been publicly traded since October 2006. Our general partner is Breitburn GP, a Delaware limited liability company, also formed in 2006, and has been our wholly-owned subsidiary since June 2008. The board of directors of our General Partner (the "Board") has sole responsibility for conducting our business and managing our operations. We conduct our operations through a wholly-owned subsidiary, BOLP, and BOLP's general partner, BOGP. We own all of the ownership interests in BOLP and BOGP.

In 2008, we acquired Breitburn Management and its interest in our General Partner, resulting in Breitburn Management and our General Partner becoming our wholly-owned subsidiaries. Breitburn Management manages our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. See Note 5 to the consolidated financial statements in this report for more information regarding our relationship with Breitburn Management.

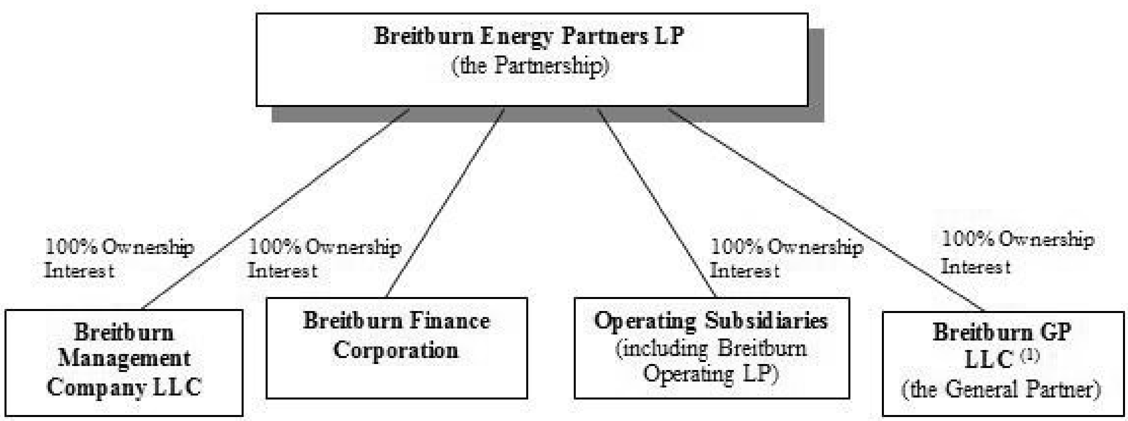
Available Information

Our internet website address is www.breitburn.com. We make available, free of charge at the "Investor Relations" portion of our website, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after such reports are electronically filed with, or furnished to, the SEC. The information contained on our website does not constitute part of this report.

The SEC maintains an internet website that contains these reports at www.sec.gov. Any materials that the Partnership files with the SEC may be read or copied 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) 732-0330.

Structure

The following diagram depicts our organizational structure as of December 31, 2015:



(1) Breitburn GP LLC holds the general partner interest in the Partnership.

As of December 31, 2015 and February 25, 2016, we had approximately 213.5 million and 213.7 million, respectively, common units representing limited partner interests in us ("Common Units") outstanding. As of December 31, 2015 and February 25, 2016, we had 8.0 million 8.25% Series A Cumulative Redeemable Perpetual Preferred Units ("Series A Preferred Units") outstanding. As of December 31, 2015 and February 25, 2016, we had 48.8 million and 49.4 million, respectively, 8.0% Series B Perpetual Convertible Preferred Units ("Series B Preferred Units") outstanding.

Long-Term Business Strategy

Our long-term goals have been to manage our current and future oil, NGL and natural gas producing properties for the purpose of generating cash flow and making distributions to our unitholders. Our core investment strategy has included the following principles:

- acquire long-lived assets with low-risk exploitation and development opportunities;
- use our technical expertise and state-of-the-art technologies to identify and implement successful exploitation techniques to optimize reserve recovery;
- reduce cash flow volatility through commodity price and interest rate derivatives; and
- maximize asset value and cash flow stability through our operating expertise.

We have adjusted our business strategies in response to the steep and continued decline in commodity prices, which began at the end of 2014, by suspending distributions to common unitholders, significantly reducing our capital budgets, cutting operating and overhead costs, scaling back derivative activity and reducing our acquisition expectations. We continue to actively reassess our business strategies to address the lower commodity price environment.

Acquisitions

2015 Acquisitions

CO_2 Acquisition. On March 31, 2015, we completed the acquisition of certain CO_2 producing properties located in Harding County, New Mexico, for a total purchase price of $70.5 million (the "$CO_2$ Acquisition"), which is primarily reflected in other property, plant and equipment on the consolidated balance sheet. See Note 3 to the consolidated financial statements within this report for a discussion of this acquisition.

2014 Acquisitions

Antares Acquisition. On October 24, 2014, we completed the acquisition of certain oil and gas properties located in the Midland Basin, Texas from Antares Energy Company, in exchange for 4.3 million Common Units and $50.0 million in cash, for a total purchase price of $122.3 million (the "Antares Acquisition").

QRE Merger. On November 19, 2014, we completed the merger with QR Energy, LP, a Delaware limited partnership ("QRE"), in exchange for approximately 71.5 million Common Units and $350 million in cash (the "QRE Merger"). The QRE Merger had a transaction value of approximately $2.5 billion, including approximately $1.1 billion of QRE debt assumed and net of approximately $5.1 million of cash acquired. Our consolidated financial statements and financial and operational results reflect the combined entities since the acquisition date. The properties acquired in the QRE Merger were located in Alabama, Arkansas, Florida, Kansas, Louisiana, Michigan, New Mexico, Oklahoma and Texas.

2013 Acquisitions

Oklahoma Panhandle Acquisitions. On July 15, 2013, we completed the acquisition of principally oil properties and midstream assets located in Oklahoma, New Mexico and Texas, certain CO_2 supply contracts, certain oil swaps and interests in certain entities from Whiting Oil and Gas Corporation ("Whiting") for approximately $845 million in cash (the "Whiting Acquisition"), including post-closing adjustments. We also completed the acquisition of additional interests in certain of the acquired assets in the Oklahoma Panhandle from other sellers for an additional $30 million in July 2013.

2013 Permian Basin Acquisitions. On December 30, 2013, we completed acquisitions of oil and natural gas properties located in the Permian Basin in Texas from CrownRock, L.P. for approximately $282 million in cash (the "CrownRock III Acquisition"). We also completed the acquisition of additional interests in certain of the acquired assets in the Permian Basin from other sellers for an additional $20 million in December 2013 (together with the CrownRock III Acquisition, the "2013 Permian Basin Acquisitions").

Properties

Our properties include oil, NGL and natural gas assets as well as midstream assets located in the following producing areas: i) Midwest (Michigan, Indiana, and Kentucky), ii) Ark-La-Tex (Arkansas, Louisiana and East Texas), iii) the Permian Basin in Texas and New Mexico, iv) Mid-Continent (Oklahoma, Kansas and the Texas Panhandle), v) the Rockies (Wyoming and Colorado), vi) Southeast (Florida and Alabama) and vii) California. Our midstream assets include transmission and gathering pipelines, gas processing plants, NGL recovery plants, a controlling interest in a salt water disposal company and the 120-mile Transpetco Pipeline.

Breitburn Management manages all of our properties and employs production and reservoir engineers, geologists and other specialists, as well as field personnel. On a net production basis, we operated approximately 69% of our total production in 2015. As the operator, we design and manage the development of wells and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or other oil field services equipment used for drilling or maintaining wells on properties we operate. We engage independent contractors to provide all the equipment and personnel associated with these activities.

2016 Outlook

In 2015, oil and natural gas prices continued the rapid and substantial decline that began at the end of 2014 and that has continued into the first quarter of 2016. Due to the uncertainty regarding future commodity prices, we plan to manage our operating activities and liquidity carefully. We do not expect increased production as a result of our 2016 capital program to entirely offset production declines, and expect that will result in decreases to our production, without taking into account acquisitions, divestitures or further modifications to our capital and operating plan based on price changes through 2016. We plan to continuously evaluate our operating activity in light of commodity prices and the changes we are able to make to both our costs of operations and to our capital budget.

We expect our full year 2016 oil and gas capital spending program to be approximately $80 million, including capitalized engineering costs and excluding potential acquisitions, compared with approximately $209 million in 2015. The reduction in capital expenditures reflects our outlook for 2016 performance measured against the ongoing weakness in commodity prices. We anticipate 60% of our total capital spending will be focused on drilling and rate-generating projects and CO_2 purchases, in our core operating areas of East Texas, the Permian Basin and the Mid-Continent, that are designed to increase or add to production or reserves. We plan to drill 17 wells in Ark-La-Tex and Mid-Continent. We expect our 2016 production to be between 17.0 MMBoe and 19.7 MMBoe.

Commodity hedging remains an important part of our strategy to reduce cash flow volatility. We use swaps, collars and options for managing risk relating to commodity prices. As of February 25, 2016, we had approximately 77% of our expected 2016 production hedged, approximately 48% of our expected 2017 production hedged, approximately 10% of our 2018 production hedged and approximately 5% of our 2019 production hedged. For 2016, we have 24.8 MBbl/d of oil and 83.0 BBtu/d of natural gas hedged at average prices of approximately $85.79 per Bbl and $3.98 per MMBtu, respectively. For 2017, we have 14.8 MBbl/d of oil and 56.1 BBtu/d of natural gas hedged at average prices of approximately $83.11 per Bbl and $3.98 per MMBtu, respectively. For 2018, we have 1.5 MBbl/d of oil and 20.4 BBtu/d of natural gas hedged at average prices of approximately $64.02 per Bbl and $3.19 per MMBtu, respectively. For 2019, we have 1.0 MBbl/d of oil and 10.0 BBtu/d of natural gas hedged at average prices of approximately $56.35 per Bbl and $3.15 per MMBtu, respectively.

Reserves and Production

As of December 31, 2015, our total estimated proved reserves were 239.3 MMBoe, of which approximately 54% was oil, 8% was NGLs and 38% was natural gas. As of December 31, 2014, our total estimated proved reserves were 315.3 MMBoe, of which approximately 55% was oil, 8% was NGLs and 37% was natural gas. Net changes to our total estimated proved reserves included negative reserve revisions of 71.5 MMBoe and 20.1 MMBoe of production, resulting in a net decrease of 76.0 MMBoe from 2014 partially offset by 14.9 MMBoe in extensions and discoveries. The reserve revisions in 2015 were primarily the result of a 44.4 MMBoe decrease in oil reserves and a 3.6 MMBoe decrease in NGL reserves, driven primarily by a decrease in oil and NGL prices and a 141.6 Bcf decrease in natural gas reserves primarily due to a decrease in natural gas prices. The unweighted average first-day-of-the-month oil and natural gas prices used to determine our total estimated proved reserves as of December 31, 2015, were $50.28 per Bbl of oil for the WTI spot price and $2.59 per MMBtu of natural gas for the Henry Hub spot price, compared to $94.99 per Bbl of oil for the WTI spot price, $101.30 per Bbl of oil for the ICE Brent spot price and $4.35 per MMBtu of natural gas for the Henry Hub spot price in 2014.

The following table summarizes our estimated proved reserves and production by state as of December 31, 2015:

	As of December 31, 2015 Proved Reserves						Year Ended December 31, 2015	
	Total (MMBoe) (a)	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	% Proved Developed	% Total	Production (MBoe)	Average Daily Production (Boe/d)
Midwest	51.5	4.1	0.5	281.3	98%	21%	3,091	8,468
Ark-La-Tex	46.9	21.4	5.4	120.4	85%	20%	3,658	10,022
Permian Basin	44.6	27.9	7.9	53.2	68%	19%	4,498	12,322
Mid-Continent	32.3	25.6	4.2	14.7	44%	13%	2,814	7,710
Rockies	25.7	14.2	—	68.8	97%	11%	2,311	6,332
Southeast	20.4	18.8	1.6	0.8	82%	9%	2,038	5,585
California	17.9	17.2	—	4.1	88%	7%	1,770	4,849
Total	239.3	129.2	19.6	543.3	80%	100%	20,180	55,288
Antrim Shale (b)	42.6	—	—	255.6	100%	18%	2,233	6,118

(a) Natural gas is converted on the basis of six Mcf of gas per one Bbl of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a Bbl of oil equivalent for natural gas is significantly less than the price for a Bbl of oil.

(b) As of December 31, 2015, the Antrim Shale, included in “Midwest” above, was the only field which contained 15% or more of our total proved reserves.

The following table summarizes our production volumes, sales prices and production costs for the Antrim Shale, which accounted for 18% of our total proved reserves as of December 31, 2015:

	Antrim Shale		
	2015	2014	2013
Net Production			
Natural Gas (MMcf)	13,390	13,902	14,468
Total (MBoe)	2,233	2,317	2,411
Average Realized Sales Price			
Natural Gas price per Mcf	$ 2.94	$ 5.29	$ 3.90
Total price per Boe	$ 17.66	$ 31.79	$ 23.40
Average Production Cost per Boe			
Pre-tax lease operating expense	$ 8.54	$ 10.35	$ 11.68

See “Results of Operations” in Part II—Item 7 of this report for average realized sales price and average production cost per Boe for the Partnership in total.

As of December 31, 2015, proved undeveloped reserves were 47.3 MMBoe compared to 71.5 MMBoe as of December 31, 2014. During 2015, we incurred $63.0 million in capital expenditures and drilled 51 wells related to the conversion of estimated proved undeveloped reserves to estimated proved developed reserves. During 2015, we converted 2.4 MMBbl of oil, 1.0 MMBbl of NGLs and 15.9 Bcf of natural gas from estimated proved undeveloped reserves to estimated proved developed reserves. As of December 31, 2015, we had no estimated proved undeveloped reserves that have remained undeveloped for more than five years, and we expect to develop substantially all estimated proved undeveloped reserves within five years of the recognition of those reserves.

As of December 31, 2015, the total standardized measure of discounted future net cash flows was $1.3 billion. During 2015, we filed estimates of oil and gas reserves as of December 31, 2014 with the U.S. Department of Energy, which were consistent with the reserve data as of December 31, 2014 as reported in Note A in the supplemental information to the consolidated financial statements in this report.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices or development costs and production expenses, may require revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve estimates. See Part I—Item 1A "—Risk Factors" in this report for a description of some of the risks and uncertainties associated with our business and reserves.

The information in this report relating to our estimated proved oil and gas reserves is based upon reserve reports prepared as of December 31, 2015. Estimates of our proved reserves were prepared by Netherland, Sewell & Associates, Inc. ("NSAI") and Cawley, Gillespie & Associates, Inc. ("CGA"), independent petroleum engineering firms. NSAI prepared reserve data for all our properties except for our Postle and North East Hardesty fields in Oklahoma, which was prepared by CGA. The reserve estimates are reviewed and approved by members of our senior engineering staff and management. The process performed by NSAI and CGA to prepare reserve amounts included their estimation of reserve quantities, future producing rates, future net revenue and the present value of such future net revenue. NSAI and CGA also prepared estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a)(22) and subsequent SEC staff interpretations and guidance. In the conduct of their preparation of the reserve estimates, NSAI and CGA did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of their work, something came to their attention that brought into question the validity or sufficiency of any such information or data, they did not rely on such information or data until they had satisfactorily resolved their questions relating thereto.

The technical person, employed by our General Partner, primarily responsible for overseeing preparation of the reserves estimates and the third party reserve reports is Mark L. Pease, the President and Chief Operating Officer of our General Partner. Mr. Pease received a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines in 1979. Prior to joining our General Partner, Mr. Pease was Senior Vice President, E&P Technology & Services for Anadarko Petroleum Corporation. Mr. Pease has over 30 years of experience working in various capacities in the energy industry, including acquisition analysis, reserve estimation, reservoir engineering and operations engineering. Mr. Pease consults with NSAI and CGA during the reserve estimation process to review properties, assumptions and relevant data.

See Exhibit 99.1 to this report for the estimates of proved reserves provided by NSAI and Exhibit 99.2 to this report for the estimates of proved reserves provided by CGA. We only employ large, widely known, highly regarded and reputable engineering consulting firms. Not only the firms, but the technical persons that sign and seal the reports are licensed and certify that they meet all professional requirements. Licensing requirements formally require mandatory continuing education and professional qualifications. See Supplemental Note A to the consolidated financial statements in this report for further details about the qualifications of the technical persons at NSAI and CGA primarily responsible for preparing the reserves estimates.

Properties

Midwest (Michigan, Indiana, Kentucky)

As of December 31, 2015, our estimated proved reserves attributable to our Midwest properties were 51.5 MMBoe, or approximately 21% of our total estimated proved reserves. As of December 31, 2015, approximately 91% of our Midwest total estimated proved reserves were natural gas. For the year ended December 31, 2015, our average production from our Midwest properties was approximately 8.5 MBoe/d or 50.8 MMcfe/d. Our integrated midstream assets enhance the value of our Midwest properties as gas is sold at MichCon City-Gate prices, and we have no significant reliance on third party transportation. In 2015, we had two recompletions and completed one workover in Midwest. Our capital spending in Midwest for the year ended December 31, 2015 was approximately $3 million. We have interests in 3,719 productive wells in Midwest, and we operated approximately 59% of those wells.

The Antrim Shale underlies a large percentage of our Midwest acreage; wells tend to produce relatively predictable amounts of natural gas in this reservoir. On average, our Antrim Shale wells have an estimated proved reserve life of greater than 19 years. Since reserve quantities and production levels over a large number of wells are fairly predictable, maximizing per well recoveries and minimizing per unit production costs are the keys to profitable Antrim Shale development. Growth opportunities include infill drilling and recompletions, horizontal drilling and bolt-on acquisitions.

Our non-Antrim interests in Michigan are located in several reservoirs including the Prairie du Chien, Richfield, Detroit River Zone III and Niagaran pinnacle reefs. Our operations in the New Albany Shale of southern Indiana and northern Kentucky include 21 miles of high pressure gas pipeline that interconnects with the Texas Gas Transmission interstate pipeline.

Ark-La-Tex

The Ark-La-Tex area includes properties located in southern Arkansas, northern Louisiana and eastern Texas. These properties produce from formations including the Cotton Valley Sand, Haynesville Sand, Woodbine Sand and Smackover Carbonate.

As of December 31, 2015, estimated proved reserves attributable to our Ark-La-Tex properties were 46.9 MMBbls, or approximately 20% of our total estimated proved reserves, of which, approximately 46% were oil. For the year ended December 31, 2015 our average production was approximately 10.0 MBoe/d. Our capital spending in Ark-La-Tex for the year ended December 31, 2015 was approximately $58 million. As of December 31, 2015, we had interests in 3,103 productive wells in Ark-La-Tex, and we operated 96% of those wells. During 2015, we drilled 28 gross wells and completed 47 workovers.

Permian Basin

Our Permian Basin properties are primarily located in the southern Midland Basin and Eastern Shelf in Texas and New Mexico. As of December 31, 2015, estimated proved reserves attributable to our Permian Basin properties were 44.6 MMBoe, or approximately 19% of our total estimated proved reserves. As of December 31, 2015, approximately 63% of our Permian Basin total estimated proved reserves were oil, 17% were NGLs and 20% were natural gas. For the year ended December 31, 2015, our average production from the Permian Basin was approximately 12.3 MBoe/d. In 2015, we drilled 23 gross new productive development wells, three recompletion and completed six workovers in the Permian Basin. Our capital spending in the Permian Basin for the year ended December 31, 2015 was approximately $65 million. In total, we have interests in 3,164 productive wells in the Permian Basin, and we operated approximately 45% of those wells.

Mid-Continent

Our Mid-Continent area includes properties located in western Oklahoma, southwestern Kansas and the Texas Panhandle. These properties produce from regionally significant geologic formations such as the Cottage Grove, Morrow, Atoka, Redfork and Lansing. As of December 31, 2015, estimated proved reserves attributable to our Mid-Continent properties were 32.3 MMBoe, or approximately 13% of our total estimated proved reserves. Approximately 79% of our Mid-Continent total estimated proved reserves were oil, 13% were NGLs and 8% were natural gas. For the year ended December 31, 2015, the properties produced approximately 7.7 MBoe/d. In 2015, we drilled two gross new productive development wells and completed 5 workovers in the Mid-Continent. Our capital spending in the Mid-Continent for the year ended December 31, 2015 was approximately $26 million primarily attributable to CO_2 purchases. In total, we have interests in 784 productive wells, and we operated approximately 86% of those wells.

The most significant of our Mid-Continent properties are the Postle Field and the Northeast Hardesty Unit, both of which are located in Texas County, Oklahoma. CO_2 miscible flooding has been on-going in the Postle Field since 1995. CO_2 for the projects is sourced from the Bravo Dome Field in eastern New Mexico. We are also the sole owner of the Dry Trails gas plant located at the Postle Field complex. This plant is comprised of two trains, each with a processing capacity of approximately 40 MMcf/d. Gas is processed to recover marketable hydrocarbon components from the wellhead stream and capture CO_2 gas for recompression and reuse in the flooding process. In addition, we are the sole owner of a collection of facilities and CO_2 transportation pipelines delivering product from New Mexico to the Postle and Northeast Hardesty fields.

Rockies

Our Rockies assets consist primarily of oil properties in the Powder River Basin in eastern Wyoming and Wind River and Big Horn Basins in central Wyoming and natural gas properties in the Evanston and Green River Basins in southwestern Wyoming. We also own non-operated producing assets in Weld County, Colorado.

As of December 31, 2015, estimated proved reserves attributable to our properties in the Rockies were 25.7 MMBoe, or approximately 11% of our total estimated proved reserves. As of December 31, 2015, approximately 55% of our Wyoming total estimated proved reserves were oil and 45% were natural gas. For the year ended December 31, 2015, our average production from our fields in Wyoming and Colorado were approximately 6.3 MBoe/d. In 2015, we drilled two gross new productive development wells, and completed three workovers in Wyoming. Our capital spending in Wyoming for the year ended December 31, 2015 was approximately $1 million. In total, we have interests in 980 productive wells in Wyoming, and we operated approximately 66% of those wells. Our non-operated assets in Colorado consist of 338 productive wells.

Southeast

Our Southeast producing area is comprised of significant holdings in two major geologic trends, the Sunniland trend in southwest Florida and the Jay trend in the northwest Florida Panhandle. These properties produce from the Cretaceous formations of the South Florida Basin and the Smackover Carbonate formation, respectively.

Both of our assets in the Southeast are characterized by large hydrocarbon resources in place. The Jay/Little Escambia Creek Unit ("Jay Unit"), which straddles the Alabama/Florida state lines, has been under nitrogen miscible gas injection since 1980. We operate a 70 acre processing and handling facility within the Jay Unit that separates oil, marketable hydrocarbon components and sulfur from the produced fluid stream. The remaining nitrogen rich gas is recompressed and reused in the flood process. Additional volumes of injected nitrogen are sourced from two operated air separation units located in Flomaton, Alabama in the north area of the field.

As of December 31, 2015, estimated proved reserves attributable to our assets in the Southeast were 20.4 MMBoe, or approximately 9% of our total estimated proved reserves, of which approximately 92% were oil. For the year ended December 31, 2015, our average Southeast production was approximately 5.6 MBoe/d. In 2015, we drilled two new gross productive development wells and completed 15 workovers in our assets in the Southeast. Our capital spending for the year ended December 31, 2015 was approximately $42 million. As of December 31, 2015, we had interests in 94 productive wells in the Southeast, and we operated 96% of those wells.

California

As of December 31, 2015, estimated proved reserves attributable to our California properties were 17.9 MMBoe, or approximately 7% of our total estimated proved reserves. As of December 31, 2015, approximately 96% of our California total estimated proved reserves were oil. For the year ended December 31, 2015, our average California production was approximately 4.8 MBoe/d. In 2015, we drilled five gross productive wells, four recompletions and one workover in California. Our capital spending in California for the year ended December 31, 2015 was approximately $14 million. In total, we have interests in 570 productive wells in California, and we operated 100% of those wells.

Our operations in California are concentrated in several large, complex oil fields within the Los Angeles Basin. We also operate oil properties in the San Joaquin Basin in Kern County, California.

Productive Wells

The following table sets forth information for our properties as of December 31, 2015, relating to the productive wells in which we owned a working interest. Productive wells consist of producing wells and wells capable of production. Gross wells are the total number of productive wells in which we have an interest, and net wells are the sum of our fractional working interests owned in the gross wells. We had approximately 43 wells with multiple completions as of December 31, 2015.

	Oil Wells		Gas Wells	
	Gross	Net	Gross	Net
Operated	5,329	5,055	3,234	2,439
Non-operated	1,776	88	2,075	710
Total	7,105	5,143	5,309	3,149

Developed and Undeveloped Acreage

The following table sets forth information for our properties as of December 31, 2015 relating to our leasehold acreage. Developed acres are acres spaced or assigned to productive wells. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of gas or oil, regardless of whether such acreage contains proved reserves. Gross acres are the total number of acres in which a working interest is owned. Net acres are the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Midwest	510,777	266,724	28,289	27,084	539,066	293,808
Ark-La-Tex	116,685	75,535	1,367	765	118,052	76,300
Permian Basin	91,401	62,090	31,876	22,698	123,277	84,788
Mid-Continent	140,982	81,328	3,826	3,826	144,808	85,154
Rockies	176,392	100,492	28,666	9,653	205,058	110,145
Southeast	54,668	48,836	8,020	3,268	62,688	52,104
California	3,997	3,257	41	41	4,038	3,298
Total	1,094,902	638,262	102,085	67,335	1,196,987	705,597

The following table lists the net undeveloped acres as of December 31, 2015, the net acres expiring in the years ending December 31, 2016, 2017 and 2018, and, where applicable, the net acres expiring that are subject to extension options.

		2016 Expirations		2017 Expirations		2018 Expirations	
	Net Undeveloped Acreage	Net Acreage without Extension Option	Net Acreage with Extension Option	Net Acreage without Extension Option	Net Acreage with Extension Option	Net Acreage without Extension Option	Net Acreage with Extension Option
Midwest	27,084	1,181	10,847	544	917	40	—
Ark-La-Tex	765	3	30	—	13	29	7
Permian Basin	22,698	140	—	63	321	260	3
Mid-Continent	3,826	—	—	3	—	—	—
Rockies	9,653	120	—	960	—	36	—
Southeast	3,268	2,207	—	330	—	3,292	—
California	41	—	—	—	—	34	—
Total	67,335	3,651	10,877	1,900	1,251	3,691	10

As of December 31, 2015, we held more than 117,000 net acres in the developing Utica-Collingwood shale play in Michigan. Approximately 94% of this acreage is held by production and is included in the developed acreage in the above table. As of December 31, 2015, we also held more than 57,000 net acres in the developing A1-Carbonate play in Michigan, approximately 97% of which is held by production.

Drilling Activity

Drilling activity and production optimization projects are on lower risk, development properties. The following table sets forth information for our properties with respect to wells completed during the years ended December 31, 2015, 2014 and 2013. Productive wells are those that produce commercial quantities of oil and gas, regardless of whether they produce a reasonable rate of return. No exploratory wells were drilled during the periods presented.

	Year Ended December 31,		
	2015	2014	2013
Gross development wells:			
Productive	62	170	119
Dry	—	1	3
Total	62	171	122
Net development wells:			
Productive	45	160	105
Dry	—	1	3
Total	45	161	108

As of December 31, 2015, we had the following wells in progress: two gross and one net well in Ark-La-Tex and one gross and one net well in the Southeast.

Delivery Commitments

As of December 31, 2015, we had no material delivery commitments.

Sales Contracts

We have a portfolio of oil, NGL and natural gas sales contracts with large, established refiners and utilities. Our sales contracts are sold at market-sensitive or spot prices. Because commodity products are sold primarily on the basis of price and availability, we are not dependent upon one purchaser or a small group of purchasers. During 2015, our largest purchasers were Shell Trading (US) Company ("Shell Trading"), which accounted for approximately 24% of our net sales revenues, and Plains Marketing ("Plains Marketing"), which accounted for approximately 12% of our net sales revenues. See Note 20 to the consolidated financial statements in this report for a discussion of significant customers for the years ended December 31, 2015, 2014 and 2013.

Commodity Prices

We analyze the prices we realize from the sales of all our produced products, including our crude oil, NGLs, and natural gas and the impact on those prices of differences in market-based index prices and the effects of our derivative activities. We market our oil and natural gas production to a variety of purchasers based upon the NYMEX posted prices for WTI and Natural Gas, as well as on the geographic regional U.S. posted prices for all products. The NYMEX WTI posted price of oil is the widely used benchmark in the pricing of domestic oil in the United States. The relative value of crude oil is mainly determined by its quality and geographic location. In the case of NYMEX WTI posted pricing, this oil is light and sweet, deemed 40 degrees API, and is priced for delivery at Cushing, Oklahoma. In general, produced products with fewer transportation requirements result in higher realized pricing for producers. Historically there has been a strong relationship between changes in NGL and crude oil prices. NGL prices are correlated to North American supply and petrochemical demands.

Our Permian Basin oil trades at a discount to WTI posted prices due to the deduction of transportation costs, and our Permian Basin NGLs trade at a discount due to processing fees, profit sharing and transportation. Our Mid-Continent oil trades at a discount to WTI posted prices primarily due to transportation and quality, and our Mid-Continent NGLs trade at a discount due to regional market demand and transportation. Our Rockies oil trades at a significant discount to WTI posted prices because of its distance from a major refining market and the fact that our central Wyoming production is priced relative to the Western Canadian Select benchmark. Our Southwestern Wyoming production is priced relative to Flint Hills Resources Wyoming Sweet posted prices. Our Ark-La-Tex oil trades at a premium to WTI posted prices due to local refinery market supply. Our oil from the Sunniland Trend in Florida trades at a discount to WTI posted prices primarily because it is heavy crude and is transported via barge to market. Our oil from the Jay Field in Florida also trades at a discount to WTI posted price due to transportation costs and quality. Our California oil is generally in proximity to the extensive Los Angeles refining market and trades in accordance with that local market, which competes with waterborne crude imports.

In 2015, the WTI posted price averaged approximately $48 per Bbl, compared with $93 a year earlier. The monthly average WTI posted prices during 2015 ranged from a high of $60 per Bbl in June to a low of $37 per Bbl in December. As of February 16, 2016, the WTI spot price during 2016 has averaged $31 per Bbl.

Our Midwest properties have favorable natural gas supply and demand characteristics due to their proximity to the Northeast, allowing us to sell our natural gas production at a slight premium to posted prices. Our Rockies area natural gas generally trades at a discount to NYMEX due to its location and the regional supply and demand market balances. Prices for natural gas have historically fluctuated widely, and many regional markets are aligned with the local supply and demand conditions in those regional markets rather than with the overall U.S. market. Fluctuations in the price for natural gas in the United States are closely associated with the volumes produced in North America and the inventory in underground storage relative to customer demand. U.S. natural gas prices are also typically higher during the winter period when demand for heating is greatest. During 2015, the monthly average Henry Hub posted price ranged from a high of $2.99 per MMBtu in January to a low of $1.93 per MMBtu in December. During 2015, the Henry Hub posted price averaged approximately $2.62 per MMBtu. As of February 16, 2016, the Henry Hub posted price during 2016 has averaged $2.22 per MMBtu.

See Part I—Item 1A "—Risk Factors" — "Risks Related to Our Business — Oil, NGL and natural gas prices and differentials are highly volatile. Declines in commodity prices, especially steep declines in the price of oil, have adversely affected, and in the future will adversely affect, our financial condition and results of operations, cash flow, ability to reinstate distributions, access to the capital markets and ability to grow. " We ceased paying distributions in late 2015, and we do not expect to reinstate distributions in 2016. Sustained depressed prices of oil and natural gas will also adversely affect our assets, development plans, results of operations and financial position, perhaps materially. — "Low oil and natural gas prices, declines in the trading prices of our debt and equity securities and concern about the global financial markets have limited our ability to obtain funding in the capital and credit markets on terms we find acceptable, and could limit our ability to obtain additional or continued funding under our credit facility or obtain funding at all." in this report.

Our operating expenses are responsive to changes in commodity prices. We experience pressure on operating expenses that is highly correlated to oil prices for specific expenditures such as lease fuel, electricity, drilling services and severance and minerals-based property taxes.

Derivative Activity

Our revenues and net income are sensitive to oil and natural gas prices. We enter into various derivative contracts intended to achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas. We currently maintain derivative arrangements for a significant portion of our oil and gas production. Currently, we use a combination of fixed price swap and option arrangements to economically hedge NYMEX WTI, ICE Brent and LLS oil prices and Henry Hub and MichCon City-Gate natural gas prices. 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 oil and natural gas prices on our cash flow from operations for those periods. While our commodity price risk management program is intended to reduce our exposure to commodity prices and assist with stabilizing cash flow to the extent we have hedged a significant portion of our expected production and the cost for goods and services increases, our margins would be adversely affected. For a more detailed discussion of our derivative activities, see Part II—Item 7A "—Quantitative and Qualitative Disclosures About Market Risk" and Note 4 to the consolidated financial statements included in this report.

Competition

The oil and gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in all aspects of our business, including acquiring properties and oil and gas leases, marketing oil and gas, contracting for drilling rigs and other equipment necessary for drilling and completing wells and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources permit.

In regards to the competition we face for drilling rigs and the availability of related equipment, the oil and gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel in the past, which has delayed development drilling and other exploitation activities and has caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program. Competition is also strong for attractive oil and gas producing properties, undeveloped leases and drilling rights, which may affect our ability to compete satisfactorily when attempting to make further acquisitions. See Item 1A "—Risk Factors" — "Risks Related to Our Business — We may be unable to compete effectively with other companies in the oil and gas industry, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders." in this report.

Title to Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. Prior to completing an acquisition of producing oil leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, we believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Under our credit facility, we have granted the lenders a lien on substantially all of our oil and gas properties. Under our Senior Secured Notes (as defined below), we also have granted our noteholders a second lien on substantially all of our oil and gas properties. Our properties are also subject to customary royalty and other interests, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Some of our oil and gas leases, easements, rights-of-way, permits, licenses and franchise ordinances require the consent of the current landowner to transfer these rights, which in some instances is a governmental entity. We believe that we have obtained sufficient third party consents, permits and authorizations for us to operate our business in all material respects. With respect to any consents, permits or authorizations that have not been obtained, we believe that the failure to obtain these consents, permits or authorizations have no material adverse effect on the operation of our business.

Seasonal Nature of Business

Seasonal weather conditions, especially freezing conditions in Michigan and Wyoming and tropical storms and hurricanes in the Gulf Coast, and lease stipulations can limit our drilling activities and other operations in certain of the areas in which we operate, and, as a result, we seek to perform the majority of our drilling during the non-winter months. These seasonal anomalies can pose challenges for meeting our well drilling objectives and increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Environmental Matters and Regulation

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

- require the acquisition of various permits before exploration, drilling or production activities commence;
- prohibit some or all of the operations of facilities deemed in non-compliance with regulatory requirements;
- restrict the types, quantities and concentration of various substances 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 certain 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, plug abandoned wells and restore drilling sites.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, the United States Congress ("Congress"), state legislatures and federal and state agencies frequently revise environmental laws and regulations, and the clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

Waste Handling. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. The U.S. Environmental Protection Agency ("EPA") has delegated authority to the individual states to administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Hazardous Substances. 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 current and past owner or operator of the site where the release occurred, and anyone who disposed 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. Despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses oil and natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be held jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been 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 many years. Although we believe that we have utilized operating and waste disposal practices that were standard in 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, some of our 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. From time to time, we have discovered evidence that petroleum spills or releases have occurred in the past at some of the properties owned or leased by us. 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 analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, 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. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. In September 2015, new EPA and U.S. Army Corps of Engineers rules defining the scope of the EPA's and the Corps' jurisdiction became effective. To the extent the rule expands the scope of the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of Clean Water Act programs, and implementation of the rule has been stayed pending resolution of the court challenge. The Clean Water Act also imposes spill prevention, control, and countermeasure requirements, including requirements for appropriate containment berms and similar structures, to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The primary federal law for oil spill liability is the Oil Pollution Act ("OPA") which establishes a variety of requirements pertaining to oil spill prevention, containment, and cleanup. OPA applies to vessels, offshore facilities and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, are required to develop and implement plans for preventing and responding to oil spills and, if a spill occurs, may be subject to oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from the spill. Effective as of September 2015, comparable California regulations require spill contingency plans for inland oil and gas facilities.

Underground Injection Control ("UIC"). The Safe Drinking Water Act ("SDWA") and comparable state laws regulate the construction, operation, permitting and closure of injection wells that place fluids underground for storage or disposal. Under the SDWA's UIC Program, producers must obtain federal or state Class II injection well permits and routinely monitor and report fluid volumes, pressures and chemistry, and conduct mechanical integrity tests on injection wells. While the EPA itself implements the UIC Program for Class II wells (which are used to inject brines and other fluids associated with oil and gas production) in some of the states in which we operate, other states in which we operate, such as California, Oklahoma and Texas, have primary enforcement authority with respect to the regulation of Class II wells. In response to recent seismic events near underground injection wells used for the disposal of oil and gas-related wastewater, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. As a result of these concerns, regulators in some states are considering additional requirements related to seismic safety. For example, the Texas Railroad Commission ("RRC") in October 2014 adopted new oil and gas permit rules for wells used to dispose of saltwater and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. Similarly, in July 2015 and January 2016, the Oklahoma Corporation Commission ("OCC") issued various orders and regulations applicable to disposal operations in specific counties in Oklahoma. These rules require that disposal well operators, among other things, conduct additional mechanical integrity testing, ensure that their wells are not injecting wastes in targeted formations and/or reduce the volumes of wastes disposed in such wells.

In addition, in July 2014, the EPA sent a letter to the California Environmental Protection Agency and California Natural Resources Agency describing "serious deficiencies" in the state's UIC Program and setting forth comprehensive requirements and deadlines for bringing the program into compliance with federal regulations by February 2017. In its letter, the EPA mandated an in-depth review of all existing Class II wells in California that may be injecting into non-exempt aquifers as well as a review of the state's aquifer exemption process. In addition, the EPA directed the state to prohibit new and existing injections into aquifers that have not been approved as exempt by the EPA by February 15, 2017. The state responded by promising to comply with the EPA's directives through a combination of rulemaking and administrative orders. This increased scrutiny of Class II wells has resulted in the California Department of Oil, Gas and Geothermal Resources ordering the closure of 15 injection wells in October 2015; additional closures are expected. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to continue production may be delayed or limited, which could have an adverse effect on our results of operation and financial position.

Air Emissions. The federal 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 air pollutants at specified sources. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, the EPA has adopted new rules under the Clean Air Act that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. The Clean Air Act also imposes 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, and California air quality laws and regulations are in many instances more stringent than comparable federal laws and regulations. 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.

Regulatory requirements relating to air emissions are particularly stringent in Southern California. 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.

Hydraulic Fracturing. Hydraulic fracturing involves the injection of water, sand, and chemicals under pressure into dense subsurface rock formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel, and in February 2014 issued guidance for such activities. The EPA has also issued final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing, and proposed in April 2015 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the Bureau of Land Management finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision has not yet been issued.

At the state level, several states, including California, Florida, Oklahoma, Texas, and Wyoming, have adopted and/or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, the California Department of Conservation rules, effective July 2015, require the approval of Well Stimulation Treatment Notices before starting stimulation treatment, disclosure of the fluids used and adoption of groundwater monitoring and water management plans. They also govern resident notifications, storage and handling of fluids and well integrity. At this time, we cannot predict the impact of these rules on the Partnership's operations; however, we do not expect any material adverse impact to result from the implementation of these rules. In addition, several local jurisdictions in California have proposed and several jurisdictions in Florida have proposed or adopted, various forms of moratoria or bans on hydraulic fracturing. In some cases, these measures include broad terms which, if enacted or upheld, could affect current operations. We do not believe that any current local proposal will have a material adverse effect on the Partnership as a whole.

The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and, in June 2015, the EPA released its draft report on the potential impacts of hydraulic fracturing on water resources. The EPA report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. The draft report is expected to be finalized after a public comment period and a formal review by the EPA's Science Advisory Board. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These or future studies could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Climate Change. In response to findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. These regulations include limits on tailpipe emissions from motor vehicles and pre-construction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis. Recently, in December 2015, the EPA finalized rules that added new sources to the scope of the greenhouse gases monitoring and reporting rules. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. In addition, in August 2015, the EPA announced proposed rules that would establish new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities, as part of an overall effort to reduce methane emissions by up to 45 percent by 2025. These new and proposed rules could result in increased compliance costs for the Partnership.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and many of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the implementation of state and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

California has been one of the leading states in adopting greenhouse gas emission reduction requirements, and has implemented a cap and trade program as well as mandates for renewable fuels sources. California's cap and trade program requires us to report our greenhouse gas emissions and essentially sets maximum limits or caps on total emissions of greenhouse gases from all industrial sectors that are or become subject to the program. This includes the oil and natural gas extraction sector of which we are a part. Our main sources of greenhouse gas emissions for our Southern California oil and gas operations are primarily attributable to emissions from internal combustion engines powering generators to produce electricity, flares for the disposal of excess field gas and drilling rigs. Under the California program, the cap declines annually from 2013 through 2020. We will be required to obtain authorizations for each metric ton of greenhouse gases that we emit, either in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. A portion of the allowance will be granted by the state, but any shortfall between the state-granted allowance and the facility's emissions will have to be addressed through the purchase of additional allowances either from the state or a third party. The availability of allowances will decline over time in accordance with the declining cap, and the cost to acquire such allowances may increase over time. However, we do not expect the cost to be material to our operations.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements or they could promote the use of alternative fuels and thereby decrease demand for the oil and gas that we produce. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. Such climatic events could have an adverse effect on our financial condition and results of operations.

Pipeline Safety. Some of our pipelines are subject to regulation by the U.S. Department of Transportation ("DOT") and analogous state agencies in some cases under the Pipeline Safety Improvement Act of 2002, which was reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The DOT, through the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), has established a series of rules that require pipeline operators to develop and implement integrity management programs for gas, NGL and condensate transmission pipelines as well as certain low stress pipelines and gathering lines transporting hazardous liquids, such as oil, that, in the event of a failure, could affect "high consequence areas." "High consequence areas" are currently defined to include areas with specified population densities, buildings containing populations with limited mobility, areas where people may gather along the route of a pipeline (such as athletic fields or campgrounds), environmentally sensitive areas and commercially navigable waterways. Under the DOT's regulations, integrity management programs are required to include baseline assessments to identify potential threats to each pipeline segment, implementation of mitigation measures to reduce the risk of pipeline failure, periodic reassessments, reporting and record keeping. In two steps taken in 2008 and 2010, PHMSA extended its integrity management program requirements to hazardous liquid gathering lines located in "unusually sensitive areas," such as locations containing sole-source drinking water aquifers, endangered species or other protected ecological resources.

Also, in March of 2015, PHMSA finalized new rules applicable to gas and hazardous liquid pipelines that, among other changes, impose new post-construction inspections, welding, gas component pressure testing requirements, as well as requirements for calculating pressure reductions for immediate repairs on liquid pipelines. More recently, in October 2015, PHMSA proposed new regulations for hazardous liquid pipelines that would significantly extend and expand the reach of certain PHMSA integrity management requirements, regardless of the pipeline's proximity to a high consequence area. The proposal also requires new reporting requirements for certain unregulated pipelines, including all gathering lines. Additional future regulatory action expanding PHMSA jurisdiction and imposing stricter integrity management requirements is likely. For example, in December 2015, the Senate Commerce Committee approved legislation that, among other things, requires PHMSA to conduct an assessment of its inspections process and integrity management programs for natural gas and hazardous liquid pipelines. The legislation could also require PHMSA to prioritize various rulemakings required by the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 and propose and finalize the rules mandated by the Act. If enacted, this legislation could result in PHMSA proposing additional integrity management requirements for our regulated pipelines. At this time, we cannot predict the cost of such requirements, but they could be significant. Moreover, fines and penalties may be imposed on pipeline operators that fail to comply with PHMSA requirements, and such operators may also become subject to orders or injunctions restricting pipeline operations. We have had fines and penalties imposed or threatened based on claimed paperwork and documentation omissions. Violations of the pipeline safety laws and regulations that occur after January 2012 can result in fines of up to $200,000 per violation per day, with a maximum of $2 million for a series of violations.

Endangered Species. The Endangered Species Act and similar state statutes prohibit certain actions that harm endangered or threatened species and their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or oil and gas development. For example, in March 2014, the U.S. Fish and Wildlife Service listed as threatened the lesser prairie chicken, whose habitat includes portions of the Partnership's areas of operations. As a result, landowners and drilling companies are restricted from undertaking activities that harm the lesser prairie chicken without a permit. Landowners and businesses can, however, enter into certain range-wide conservation planning agreements to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee in order to limit the regulatory impact of the species' presence. This could result in increased costs to us, and could delay or restrict drilling program activities, any of which could adversely impact our business. The presence of any protected species or the final designation of previously unprotected species as threatened or endangered in areas where we operate could result in increased costs from species protection measures or could result in limitations, delays, or prohibitions on our exploration and production activities that could have an adverse effect on our ability to develop and produce our reserves.

Activities on Federal Lands. Oil and natural gas exploration, development and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the U.S. Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. The Partnership's exploration and production operations include activities on federal lands. For those current activities as well as for future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA are required. This process has the potential to delay, limit or increase the cost of developing oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

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

We believe that compliance with existing requirements will not have a material adverse effect on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2015. Additionally, we are not aware of any environmental issues or claims that will require material capital expenditures during 2016. However, accidental spills or releases may occur in the course of our operations, and we cannot assure you that we will not incur substantial costs and liabilities as a result of such spills or releases, including those relating to claims for damage to property and persons. In addition, we expect to be required to incur remediation costs for property, wells and facilities at the end of their useful lives. Moreover, we cannot assure you that the passage of more stringent laws or regulations in the future will not have a negative impact on our business, financial condition and results of operations or ability to make distributions to our unitholders.

Other Regulation of the Oil and Gas Industry

The oil and gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Production Regulation. Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate, also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

The various states regulate the drilling for, and the production of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Production taxes vary by state. All states in which we operate impose ad valorem taxes on our oil and gas properties. Various states regulate the drilling for, and the production, gathering and sale of, oil, NGLs and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Currently, Alabama, Arkansas, Florida, Indiana, Kansas, Kentucky, Louisiana, Michigan, New Mexico, Oklahoma, Texas, and Wyoming impose severance taxes on producers at rates ranging from 1% to 13% of the value of the gross product extracted. Wyoming and Oklahoma wells that reside on Native American or federal land are subject to an additional tax of 8.5% and 8.0%, respectively. Florida sulfur sales are subject to a tax of $6.13 per long ton. In Wyoming, Florida and Michigan, reduced rates may apply to certain types of wells and production methods, such as new wells, renewed wells, stripper production and tertiary production. California does not currently impose a severance tax but taxes minerals in place. Attempts by California to impose a similar tax have been introduced in the past.

States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowances from oil and gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill. Our Los Angeles Basin properties are located in urbanized areas, and certain drilling and development activities within these fields require local zoning and land use permits obtained from individual cities or counties. These permits are discretionary and, when issued, usually include mitigation measures which may impose significant additional costs or otherwise limit development opportunities.

Natural Gas Gathering Pipeline Regulation. Section 1(b) of the Natural Gas Act (“NGA”) exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission (“FERC”) as a natural gas company under the NGA. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, and, therefore, the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels. If our natural gas gathering pipelines were subject to FERC’s jurisdiction, we would be required to file a tariff with FERC, provide a cost justification for the transportation charge and obtain certificate(s) of public convenience and necessity for the FERC-regulated pipelines. Our natural gas gathering operations could be adversely affected should they be subject to the more stringent application of state or federal regulation of rates and services.

Our natural gas gathering operations are subject to regulation in the various states in which we operate. The level of such regulation varies by state. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties. Our natural gas gathering operations also may be or become subject to additional safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Natural Gas Transportation Pipeline Regulation. Our sole interstate natural gas pipeline is an 8.3 mile pipeline in Kentucky that connects with the Texas Gas Transmission interstate pipeline. Under the NGA, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services includes the rates charged for the services, terms and conditions of service, certification and construction of new facilities, the extension or abandonment of services and facilities, the maintenance of accounts and records, the acquisition and disposition of facilities, the initiation and discontinuation of services and various other matters. Natural gas companies may not charge rates that have been determined not to be just and reasonable by FERC. In addition, FERC prohibits FERC regulated natural gas facilities from unduly preferring, or unduly discriminating against, any person with respect to pipeline rates or terms and conditions of service or other matters. Our 8.3 mile pipeline is subject to a limited jurisdiction FERC certificate, and we are not currently required to maintain a tariff at FERC. We cannot be assured that our 8.3 mile pipeline will always maintain its limited jurisdiction status, and we may be required to establish rates and file a FERC tariff in the future, which may have an adverse impact on our revenues. Pursuant to FERC's jurisdiction, existing rates and/or other tariff provisions may be challenged by complaint and rate increases proposed by the pipeline or other tariff charges may be challenged by protest. A successful complaint or protest related to our facilities could have an adverse impact on our revenue.

Our intrastate natural gas transportation pipelines are subject to regulation by applicable state regulatory commissions that can affect the rates we charge and terms of service. The level of such regulation varies by state. Although state regulations are typically less onerous than FERC, state regulations typically require pipelines to charge just and reasonable rates and to provide service on a non-discriminatory basis. Additionally, FERC has adopted certain regulations and reporting requirements applicable to intrastate and Hinshaw natural gas pipelines that provide certain interstate services subject to FERC's jurisdiction. We could become subject to such regulations and reporting requirements in the future to the extent that any of our intrastate pipelines were to begin providing, or were found to provide, such interstate services. Failure to comply with federal or state regulations can result in the imposition of administrative, civil and criminal penalties.

Additional proposals and proceedings that might affect the natural gas pipeline industry are pending before Congress, FERC and in the courts. We cannot predict the ultimate impact of these on our natural gas operations. We do not believe that we would be affected by any such actions materially differently than other midstream natural gas companies with whom we compete.

Liquids Pipeline Regulation. We own a 51 mile oil pipeline in Oklahoma and Texas that is a common carrier pipeline and subject to regulation by FERC under the October 1, 1977, version of the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 ("EPAct 1992"). The ICA and its implementing regulations give FERC authority to regulate the rates charged for service on the interstate common carrier liquids pipelines and generally require the rates and practices of interstate liquids pipelines to be just and reasonable and nondiscriminatory. The ICA also requires these pipelines to keep tariffs on file with FERC that set forth the rates the pipeline charges for providing transportation services and the rules and regulations governing these services. EPAct 1992 and its implementing regulations allow interstate common carrier oil pipelines to annually index their rates up to a prescribed ceiling level. FERC retains cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach.

Natural Gas Processing Regulation. Our natural gas processing operations are not presently subject to FERC regulation. There can be no assurance that our processing operations will continue to be exempt from other FERC regulation in the future.

Our processing facilities are affected by the availability, terms and cost of pipeline transportation. The price and terms of access to pipeline transportation can be subject to extensive federal and in state regulation. FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of NGLs. These initiatives also may indirectly affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes to our processing operations.

Regulation of Sales of Oil, Natural Gas and NGLs. The price at which we buy and sell oil, natural gas and NGLs is currently not subject to federal regulation and, for the most part, is not subject to state regulation. The availability, terms and cost of transportation significantly affect the sales of oil, natural gas and NGLs. Although the prices are not currently regulated, Congress has historically been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate prices for energy commodities might be proposed, and what effect, if any, such proposals might have on the operations of our business.

With regard to our physical purchases and sales of these energy commodities and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC, the Commodity Futures Trading Commission ("CFTC") and the Federal Trade Commission ("FTC"), as further described below. Should we violate the anti-market manipulation laws and regulations, we could be subject to fines and penalties as well as related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

In November 2009, the FTC issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1 million per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the CFTC to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to liquids swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to liquids purchases and sales. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1 million or triple the monetary gain to the person for each violation. For a description of FERC's anti market manipulation rules, see "Energy Policy Act of 2005" below.

Our sales of oil, natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation can be subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of oil and NGLs. These initiatives also may indirectly affect the intrastate transportation of oil, natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes to our oil, natural gas and NGL marketing operations, and we do not believe that we would be affected by any such FERC action materially differently than other oil, natural gas and NGL marketers with whom we compete.

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 ("EPAct 2005"). EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans and significant changes to the statutory policy that affects all segments of the energy industry. With respect to regulation of natural gas transportation, EPAct 2005 amended the NGA and the Natural Gas Policy Act ("NGPA") by increasing the criminal penalties available for violations of each Act. EPAct 2005 also added a new section to the NGA, which provides FERC with the power to assess civil penalties of up to $1,000,000 per day for each violation of the NGA and increased FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in FERC-jurisdictional transportation and the sale for resale of natural gas in interstate commerce. EPAct 2005 also amended the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of EPAct 2005, and subsequently denied rehearing. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which they were made, not misleading; or (3) engage in any act, practice or course of business that operates or would operate as a fraud or deceit upon any entity. The new anti-market manipulation rule does not apply to activities that relate only to non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, including the annual reporting requirements under Order No. 704 (described below). The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's enforcement authority. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts.

FERC Market Transparency Rules. Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers, and natural gas producers, are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

Employees

Breitburn Management, our wholly-owned subsidiary, operates our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. All of our employees, including our executives, are employees of Breitburn Management. As of December 31, 2015, Breitburn Management had 833 full time employees. Breitburn Management provides services to us as well as to our Predecessor. None of Breitburn Management's employees are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory.

Offices

Breitburn Management's principal executive offices are located at 707 Wilshire Boulevard, Suite 4600, Los Angeles, California 90017. Breitburn Management leases office space at 1401 McKinney Street, Houston, Texas 77010 and at JP Morgan Chase Tower at 600 Travis Street, Houston, Texas 77002.

Financial Information

We operate our business as a single segment. Additionally, all of our properties are located in the United States and all of the related revenues are derived from purchasers located in the United States. Our financial information is included in the consolidated financial statements and the related notes beginning on page F-1.

Item 1A. Risk Factors.

An investment in our securities is subject to certain risks described below. If any of these risks were actually to occur, our business, financial condition and results of operations could be materially adversely affected. In that case, the trading price of our Common Units could decline, we may not be able to reinstate the distributions on our Common Units and you could lose part or all of your investment.

Risks Related to Our Business

Oil, NGL and natural gas prices and differentials are highly volatile. Declines in commodity prices, especially steep declines in the price of oil, have adversely affected, and in the future will adversely affect, our financial condition and results of operations, cash flow, ability to reinstate distributions, access to the capital markets and ability to grow.

The oil, NGL and natural gas markets are highly volatile, and we cannot predict future oil, NGL and natural gas prices. Prices for oil, NGL and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, NGLs and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- domestic and foreign supply of and demand for oil, NGLs and natural gas;
- market prices of oil, NGLs and natural gas;
- level of consumer product demand;
- overall domestic and global political and economic conditions;
- political and economic conditions in producing countries, including those in the Middle East, Russia, South America and Africa;
- actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil price and production controls;
- weather conditions;
- impact of the U.S. dollar exchange rates on commodity prices;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxation;
- impact of energy conservation efforts;
- capacity, cost and availability of oil and natural gas pipelines, processing, gathering and other transportation facilities and the proximity of these facilities to our wells;
- increase in imports of liquid natural gas in the United States; and
- price and availability of alternative fuels.

Oil and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because oil, NGLs and natural gas accounted for approximately 54%, 8% and 38% of our estimated proved reserves as of December 31, 2015, respectively, and approximately 56%, 9% and 35% of our 2015 production on an MBoe basis, respectively, our financial results will be sensitive to movements in oil, NGLs and natural gas prices.

In the past, prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2015, the monthly average WTI spot price ranged from a high of $59.82 per Bbl in June to a low of $37.19 per Bbl in December while the monthly average Henry Hub natural gas price ranged from a high of $2.99 per MMBtu in January to a low of $1.93 per MMBtu in December. During the year ended December 31, 2014, the monthly average WTI spot price ranged from a high of $106 per Bbl in June to a low of $59 per Bbl in December while the monthly average Henry Hub natural gas price ranged from a high of $6.00 per MMBtu in February to a low of $3.48 per MMBtu in December. As of February 16, 2016, the WTI spot price during 2016 has averaged $31 per Bbl and the natural gas spot price at Henry Hub has averaged approximately $2.22 per MMBtu. Price discounts or differentials between WTI spot prices and what we actually receive are also historically very volatile.

Our revenue, profitability and cash flow depend upon the prices and demand for oil, NGLs and natural gas, and the steep drop in prices has significantly affected our financial results and impeded our growth, and could continue to do so. In particular, continuance of the current low oil and natural gas price environment, further declines in oil or natural gas prices or a lack of natural gas storage will negatively impact:

- our ability to reinstate Common Unit distributions;
- the value of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can produce economically;
- the amount of cash flow available for capital expenditures;
- our ability to replace our production and future rate of growth;
- our ability to borrow money or raise additional capital and our cost of such capital;
- our ability to meet our financial obligations; and
- the amount that we are allowed to borrow or have outstanding under our credit facility and our liquidity position in the event we cannot borrow or must repay amounts under our credit facility.

Historically, higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling equipment, crews and associated supplies, equipment and services. Although commodity prices have steeply declined recently, the costs associated with drilling may not decline as rapidly. Accordingly, a high cost environment could adversely affect our ability to pursue our drilling program and our results of operations.

In the past, we have raised our distribution levels on our Common Units in response to increased cash flow during periods of relatively high commodity prices. However, we have not been able to sustain those distribution levels during subsequent periods of lower commodity prices. For example, we did not pay a distribution from February 2009 until May 2010. In November 2015, in response to sustained lower commodity prices, we again elected to suspend distributions on our Common Units effective with the third monthly payment attributable to the third quarter of 2015. There is no guarantee that we will reinstate distributions on our Common Units.

Oil and natural gas prices have declined substantially and are expected to remain depressed for the foreseeable future. Sustained depressed prices of oil and natural gas will materially adversely affect our assets, development plans, results of operations and financial position.

The monthly average WTI posted prices during 2015 ranged from a high of $59.82 per Bbl in June to a low of $37.19 per Bbl in December, and the monthly average Henry Hub posted price ranged from a high of $2.99 per MMBtu in January to a low of $1.93 per MMBtu in December. As of December 31, 2015, we had approximately 77% of our expected 2016 production hedged at prices higher than those currently prevailing. In 2015, we wrote down the value of our oil and natural gas properties and revised our development plans, due to the expectation of an extended period of lower commodity prices. See "Future oil and natural gas price declines may result in further write-downs of our asset carrying values" below. In addition, sustained low prices for oil and natural gas will reduce the amounts we would otherwise have available to pay expenses, service our indebtedness and reinstate distributions to our unitholders.

Low oil and natural gas prices, declines in the trading prices of our debt and equity securities and concern about the global financial markets have limited our ability to obtain funding in the capital and credit markets on terms we find acceptable, and could limit our ability to obtain additional or continued funding under our credit facility or obtain funding at all.

Historically, we have used our cash flow from operations, borrowings under our credit facility and issuances of senior notes and additional partnership units to fund our capital expenditures and acquisitions. Low oil and natural gas prices and concern about the global financial markets could make it challenging to obtain funding in the capital and credit markets in the future. In 2013, 2014 and 2015, to a limited extent, we were able to access the debt and equity capital markets. However, the recent declines and volatility in oil and natural gas prices and in the trading prices of our debt and equity securities have significantly increased the cost of obtaining money in the capital and credit markets and limited our ability to access those markets currently as a source of funding.

These events affect our ability to access capital in a number of ways, which include the following:

- Our ability to access new debt or credit markets on acceptable terms is currently limited, and this condition may last for an unknown period of time.
- Our credit facility limits the amounts we can borrow to a borrowing base amount determined by the lenders at their sole discretion based on their valuation of our proved reserves and their internal criteria.
- We may be unable to obtain adequate funding under our credit facility because our lenders may simply be unwilling or unable to meet their funding obligations.
- The operating and financial restrictions and covenants in our credit facility and Senior Notes limit (and any future financing agreements likely will limit) our ability to finance future operations or capital needs or to engage, expand or pursue our business activities or to reinstate distributions.

Due to these factors, we cannot be certain that funding will be available, if needed and to the extent required, on acceptable terms. If funding is not available when needed, or if funding is available only on unfavorable terms, we may be unable to meet our obligations as they come due or be required to post collateral to support our obligations, or we may be unable to implement our development plans, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues, results of operations, financial condition or ability to reinstate distributions. Without funding to make acquisitions of additional properties containing proved oil or natural gas reserves, our total level of estimated proved reserves will decline as a result of our production, and we may be unable to reinstate distributions on our Common Units.

Our credit facility has substantial conditions, restrictions and financial covenants that may restrict our business and financing activities and our ability to reinstate distributions.

As of February 25, 2016, we had approximately $1.2 billion in borrowings under our credit facility outstanding. In 2015, we repaid $860 million borrowed under our credit facility. Our credit facility limits the amounts we can borrow to a borrowing base amount determined by the lenders at their sole discretion based on their valuation of our proved reserves and their internal criteria. The borrowing base at December 31, 2015 was $1.8 billion and the next semi-annual redetermination is scheduled for April 2016. Decreases in the available borrowing amount could result from declines in oil and natural gas prices, operating difficulties or increased costs, declines in reserves, lending requirements or regulations or certain other circumstances. Based upon current commodity prices and other factors at the time of future redeterminations, we expect a significant decrease in our borrowing base. Although our lenders have the discretion to redetermine the borrowing base below our current outstanding borrowings, we do not expect that to occur in April 2016. Without a waiver from our lenders, our credit facility currently provides that if the borrowing base is reduced below our current outstanding borrowings, we are required to repay the deficiency in five equal monthly installments.

We believe our existing cash resources and hedge positions should provide us with sufficient funds to meet our expected working capital needs for 2016, assuming that our borrowing base is redetermined above our current outstanding borrowings. Although we currently expect our sources of capital to be sufficient to meet our near-term liquidity needs, there can be no assurance that the lenders under our credit facility will not reduce the borrowing base to an amount below our current outstanding borrowings or that our liquidity requirements will continue to be satisfied, given current commodity prices and the discretion of our lenders to decrease our borrowing base. In addition, due to the steep declines in commodity prices and the trading prices of our debt and equity securities, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable. The cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, and reduced and, in many cases, ceased to provide any new funding. If we cannot access the capital markets and repay debt under our credit facility in connection with the borrowing base determination in April 2016, we may take other actions to raise funds to repay debt, such as selling assets or restructuring derivative contracts.

The operating and financial restrictions and covenants in our credit facility restrict, and any future financing agreements likely will restrict, our ability to finance future operations or capital needs or to engage, expand or pursue our business activities or to reinstate distributions. Our credit facility restricts, and any future credit facility likely will restrict, our ability to:

- incur indebtedness;
- grant liens;
- make certain acquisitions and investments;
- lease equipment;
- make capital expenditures above specified amounts;
- redeem or prepay other debt;
- make distributions to unitholders or repurchase units;
- enter into transactions with affiliates; and
- enter into a merger, consolidation or sale of assets.

Our credit facility restricts our ability to make distributions to unitholders or repurchase Common Units unless after giving effect to such distribution or repurchase, we remain in compliance with all terms and conditions of our credit facility and satisfy certain minimum liquidity requirements. While we currently are not restricted by our credit facility from declaring a distribution, we may be restricted from paying a distribution in the future.

We also are required to comply with certain financial covenants and ratios under the credit facility. Our ability to comply with these restrictions, covenants and conditions in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. In light of the deterioration of oil and natural gas prices, our ability to comply with these covenants and conditions may be impaired in the future. If we violate any of the restrictions, covenants, ratios or tests in our credit facility, a significant portion of our indebtedness may become immediately due and payable, our ability to make distributions will be prohibited and our lenders' commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our credit facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our credit facility, the lenders can seek to foreclose on our assets.

See Part II—Item 7 "—Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" in this report for a discussion of our credit facility covenants.

Even if we are able to pay distributions on our Common Units under the terms of our credit facility and the indenture governing our Senior Secured Notes, we may not elect to pay distributions on our Common Units because we do not have sufficient cash flow from operations following establishment of cash reserves, reduction of debt and payment of fees and expenses.

Our credit facility restricts our ability to make distributions to unitholders or repurchase units unless after giving effect to such distribution or repurchase, no event of default exists and we remain in compliance with all terms and conditions of our credit facility. For example, we were restricted from declaring a distribution on our Common Units and did not pay a distribution from February 2009 until May 2010. The indenture governing our Senior Secured Notes also restricts our ability to make distributions to our unitholders. While we currently are not restricted by our credit facility or the indenture governing our Senior Secured Notes from declaring a distribution, we have elected to suspend distributions on our Common Units and could be restricted from paying a distribution in the future.

Even if we are able to pay distributions on our Common Units under the terms of our credit facility and the indenture governing our Senior Secured Notes, we may not have sufficient available cash each quarter to pay distributions on our Common Units. Under the terms of our partnership agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses, debt reduction and the amount of any cash reserve amounts that our General Partner establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to our unitholders. We may reserve a substantial portion of our cash flow from operations for debt reduction. In the future, we may reserve a substantial portion of our cash generated from operations to develop our oil and natural gas properties and to acquire additional oil and natural gas properties in order to maintain and grow our level of oil and natural gas reserves.

The amount of cash that we actually generate will depend upon numerous factors related to our business that may be beyond our control, including among other things:

- the amount of oil and natural gas we produce;
- demand for and prices at which we sell our oil and natural gas, which prices decreased significantly in 2015 and have continued to decrease in 2016;
- the effectiveness of our commodity price derivatives;
- the level of our operating costs;
- prevailing economic conditions;
- our ability to replace declining reserves;
- continued development of oil and natural gas wells and proved undeveloped reserves;
- our ability to acquire oil and natural gas properties from third parties in a competitive market and at an attractive price;
- the level of competition we face;
- fuel conservation measures;
- alternate fuel requirements;
- government regulation and taxation; and
- technical advances in fuel economy and energy generation devices.

In addition, the actual amount of cash that we will have available for distribution will depend on other factors, including:

- our ability to borrow under our credit facility to pay distributions;
- debt service requirements and restrictions on distributions contained in our credit facility, the indenture governing our Senior Secured Notes or future debt agreements;
- the level of our capital expenditures;
- sources of cash used to fund acquisitions;
- fluctuations in our working capital needs;
- general and administrative expenses (“G&A”);
- costs of operations;
- cash settlement of hedging positions;
- timing and collectability of receivables; and
- the amount of cash reserves established for the proper conduct of our business.

In November 2015, effective with the third monthly payment attributable to the third quarter of 2015, we elected to suspend distributions on our Common Units in light of declining commodity prices. There is no guarantee that we will reinstate distributions on our Common Units.

For a description of additional restrictions and factors that may affect our ability to reinstate cash distributions, please read Part II—Item 7 “—Management’s Discussion and Analysis of Financial Condition and Results of Operations —Liquidity and Capital Resources” in this report.

Restrictive covenants under our indentures governing our senior notes may adversely affect our operations.

The indentures governing our $650 million 9.25% Senior Secured Second Lien Notes due 2020 (the “Senior Secured Notes”), $305 million 8.625% Senior Notes due 2020 (the “2020 Senior Notes”) and $850 million 7.875% Senior Notes due 2022 (the “2022 Senior Notes”) (together with the Senior Secured Notes and the 2020 Senior Notes, the “Senior Notes”) contain, and any future indebtedness we incur may contain, a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our restricted subsidiaries;
- pay distributions on, redeem or repurchase our units or redeem or repurchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;

- create or incur certain liens;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries; and
- engage in certain business activities.

As a result of these covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

A failure to comply with the covenants in the indentures governing our Senior Notes or any future indebtedness could result in an event of default under the indentures governing the Senior Notes or the future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. In addition, complying with these covenants may make it more difficult for us to successfully execute our business strategy and compete against companies who are not subject to such restrictions.

Our debt levels may limit our flexibility to obtain additional financing and pursue other business opportunities. We may not be able to generate sufficient cash flows to service all of our indebtedness and may be forced to take other actions in order to satisfy our obligations under our indebtedness, which may not be successful.

As of February 25, 2016, our total debt was $2.99 billion. Our existing and future indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on terms acceptable to us;
- covenants in our existing and future credit and debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- our access to the capital markets may be limited;
- our borrowing costs may increase;
- we will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to unitholders; and
- our debt level will make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service, or to refinance, our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. We cannot assure you that our business will generate sufficient cash flows from operating activities or that future sources of capital will be available to us in an amount sufficient to permit us to service our indebtedness or repay our indebtedness as it becomes due or to fund our other liquidity needs. In addition, there can be no assurance that we will have the ability to borrow or otherwise raise the amounts necessary to repay or refinance our indebtedness as it matures. If our operating results are not sufficient to service our current or future indebtedness or meet our debt obligations as they become due, we will be forced to take actions such as reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing all or a portion of our indebtedness, or seeking additional financing. We may not be able to effect any of these remedies on satisfactory terms or at all. We may be unable to restructure or refinance our debt, obtain additional financing or capital or sell assets on satisfactory terms, if at all. If we cannot make scheduled payments on our debt, we will be in default under the terms of the agreements governing our debt and, as a result:

- our debt holders could declare all outstanding principal and interest to be due and payable, which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements;
- the lenders under our credit facility could terminate their commitments to lend us money and foreclose against the assets securing their borrowings; and
- we could be forced into bankruptcy or liquidation.

The price of our Common Units has recently declined significantly and could decline further for a variety of reasons, resulting in a substantial loss on investment and negatively impacting our ability to raise equity capital.

The price of our Common Units decreased from $7.63 per unit on January 2, 2015 to $0.67 per unit on December 31, 2015, and was $0.53 per unit as of the close of business on February 25, 2016, and it could decline further. Such further decline could result from a variety of factors, including, among other things, sustained or further declines in commodity prices, actual or anticipated fluctuations in our operating results or financial condition, new laws or regulations or new interpretations of existing laws or regulations impacting our business, our customers' businesses, sales of our Common Units by our unitholders or by us, a downgrade or cessation in coverage from one or more of our analysts, broad market fluctuations and general economic conditions and any other factors described in this "Risk Factors" section of this report.

The liquidity of our Common Units could be adversely affected if we are delisted from NASDAQ.

On January 21, 2016, we received a deficiency notice from the Listing Qualifications Department of The NASDAQ Stock Market LLC ("NASDAQ") notifying us that our Common Units closed below the $1.00 per unit minimum bid price required by NASDAQ Listing Rule 5450(a)(1) for 30 consecutive business days. The notice also indicated that, in accordance with NASDAQ Listing Rule 5810(c)(3)(A), we have a period of 180 calendar days, or until July 19, 2016, to achieve compliance with the minimum bid price requirement. We will regain compliance with the minimum bid price requirement if at any time before July 19, 2016, the bid price for our Common Units closes at $1.00 per unit or above for a minimum of 10 consecutive business days. In the event we do not regain compliance with the minimum bid price requirement by July 19, 2016, we may be eligible for an additional 180 calendar day compliance period if we elect to transfer to the NASDAQ Capital Market so as to take advantage of the additional compliance period offered on that market. To qualify, we would be required to meet the continued listing requirement for market value of publicly held shares and all other initial listing standards for the NASDAQ Capital Market, with the exception of the bid price requirement, and would need to provide written notice of our intention to cure the deficiency during the second compliance period.

Upon delisting from the NASDAQ Global Select Market or the NASDAQ Capital Market, our Common Units would be traded over-the-counter, more commonly known as OTC. OTC transactions involve risks in addition to those associated with transactions in securities traded on the NASDAQ Global Select Market. Many OTC stocks trade less frequently and in smaller volumes than securities traded on the NASDAQ Global Select Market. We are currently evaluating our alternatives to resolve the listing deficiency. To the extent that we are unable to resolve the listing deficiency, there is a risk that our Common Units may be delisted from NASDAQ, which would adversely impact the liquidity of our Common Units and potentially result in even lower bid prices for our Common Units. Such market place volatility could also adversely affect our ability to raise additional capital.

Future oil and natural gas price declines may result in further write-downs of our asset carrying values.

Declines in oil and natural gas prices in 2015 resulted in our having to make substantial downward adjustments to our estimated proved reserves resulting in increased depletion and depreciation charges. Accounting rules require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. We are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and therefore requires a write-down. During the year ended December 31, 2015, we recorded non-cash impairment charges of approximately $2.4 billion primarily due to the impact that the sustained drop in commodity strip prices had on our projected future net revenues.

We also may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our credit facility, which in turn may adversely affect our ability to make cash distributions to our unitholders.

The production from our Oklahoma properties could be adversely affected by the cessation or interruption of the supply of CO_2 to those properties.

We use enhanced recovery technologies to produce oil and natural gas. For example, we inject water and CO_2 into formations on substantially all of our Oklahoma properties to increase production of oil and natural gas. The additional production and reserves attributable to the use of enhanced recovery methods are inherently difficult to predict. If we are unable to produce oil and gas by injecting CO_2 in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO_2 to enhance production is subject to our ability to obtain sufficient quantities of CO_2. If, under our CO_2 supply contracts, the supplier is unable to deliver its contractually required quantities of CO_2 to us, or if our ability to access adequate supplies is impeded, then we may not have sufficient CO_2 to produce oil and natural gas in the manner or to the extent that we anticipate, and our future oil and gas production volumes will be negatively impacted.

If we do not make acquisitions on economically acceptable terms, our future growth and ability to reinstate distributions will be limited.

Our ability to grow and to reinstate distributions to unitholders depends in part on our ability to make acquisitions that result in an increase in pro forma available cash per unit. We may be unable to make such acquisitions because:

- we cannot obtain financing for these acquisitions on economically acceptable terms;
- we cannot identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- we are outbid by competitors; or
- our Common Units are not trading at a price that would make the acquisition accretive.

If we are unable to acquire properties containing proved reserves, our total level of estimated proved reserves may decline as a result of our production, and we may be limited in our ability to reinstate our cash distributions.

Any acquisitions that we complete are subject to substantial risks that could reduce our ability to reinstate distributions to our unitholders. The integration of the oil and natural gas properties that we acquire may be difficult and could divert our management's attention away from our other operations.

If we do make acquisitions that we believe will increase available cash per unit, these acquisitions may nevertheless result in a decrease in available cash per unit. Any acquisition involves potential risks, including, among other things:

- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- the validity of our assumptions about reserves, future production, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

Drilling for and producing oil and natural gas are costly and high-risk activities with many uncertainties that could adversely affect our financial condition and results of operations and, as a result, our ability to reinstate distributions to our unitholders.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough oil and natural gas to be commercially viable after drilling, operating and other costs. Furthermore, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including, among other things:

- high costs, shortages or delivery delays of drilling rigs, equipment, labor or other services;
- unexpected operational events and drilling conditions;
- sustained depressed oil and natural gas prices and further reductions in oil and natural gas prices;
- limitations in the market for oil and natural gas;
- problems in the delivery of oil and natural gas to market;
- adverse weather conditions;
- facility or equipment malfunctions;
- equipment failures or accidents;
- title problems;
- pipe or cement failures;
- casing collapses;
- compliance with environmental and other governmental requirements;
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;
- lost or damaged oilfield drilling and service tools;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- pressure or irregularities in formations;
- fires, blowouts, surface craterings and explosions;
- natural disasters; and
- uncontrollable flows of oil, natural gas or well fluids.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

We may be unable to compete effectively with other companies in the oil and gas industry, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.

The oil and gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel, and we compete with other companies that have greater resources. Many of our competitors are major independent oil and gas companies and possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Factors that affect our ability to acquire properties include availability of desirable acquisition targets, staff and resources to identify and evaluate properties and available funds. Many of our larger competitors not only drill for and produce oil and gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, there is substantial competition for investment capital in the oil and gas industry. Other companies may have a greater ability to continue drilling activities during periods of low oil and gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with other companies could have a material adverse effect on our business activities, financial condition and results of operations.

We will require substantial capital expenditures to replace our production and reserves, which will reduce our cash available for distribution. We may be unable to obtain needed capital due to our financial condition, which could adversely affect our ability to replace our production and estimated proved reserves.

To fund our capital expenditures, we will be required to use cash generated from our operations, additional borrowings or the issuance of additional partnership interests, or some combination thereof. In 2016, our oil and gas capital spending program is expected to be approximately $80 million, compared to approximately $209 million in 2015 and approximately $389 million in 2014. Our planned reduction of capital expenditures in 2016, compared to 2015 and 2014, reflects our expectations of lower commodity prices in the future and declining costs of oil field equipment, drilling and other services. We expect to use cash generated from operations to fund future capital expenditures, which will reduce cash available for distribution to our unitholders. In the future, our ability to borrow and to access the capital and credit markets may be limited by our financial condition at the time of any such financing or offering and the covenants in our debt agreements, as well as by oil and natural gas prices, the value and performance of our equity securities, and adverse market conditions resulting from, among other things, general economic conditions and contingencies and uncertainties that are beyond our control. Our failure to obtain the funds for necessary future capital expenditures could have a material adverse effect on our business, results of operations, financial condition and ability to pay distributions. Even if we are successful in obtaining the necessary funds, the terms of such financings could be onerous and could limit our ability to reinstate distributions to our unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional partnership interests may result in significant unitholder dilution.

Our inability to replace our reserves could result in a material decline in our reserves and production, which could adversely affect our financial condition. We are unlikely to be able to reinstate distributions without making accretive acquisitions or capital expenditures that maintain or grow our asset base.

As a result of the significant decline in commodity prices and the impact on our liquidity and access to capital, we expect that our ability to make acquisitions will be limited in 2016. We also believe that our reduced capital program in 2016 will not be sufficient to offset production declines.

Producing oil and natural gas reservoirs are characterized by declining production rates that vary based on reservoir characteristics and other factors. The rate of decline of our reserves and production included in our reserve report at December 31, 2015 will change if production from our existing wells declines in a different manner than we have estimated and may change when we drill additional wells, make acquisitions and under other circumstances. Our future oil and natural gas reserves and production and our cash flow and ability to make distributions depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition and results of operations and reduce cash available for distribution.

We are unlikely to be able to reinstate distributions without making accretive acquisitions or capital expenditures that maintain or grow our asset base. We will need to make substantial capital expenditures to maintain and grow our asset base, which will reduce our cash available for distribution. Because the timing and amount of these capital expenditures fluctuate each quarter, we expect to reserve cash each quarter to finance these expenditures over time. We may use the reserved cash to reduce indebtedness until we make the capital expenditures.

Over a longer period of time, if we do not set aside sufficient cash reserves or make sufficient expenditures to maintain and expand our asset base, we will be unable to pay distributions from cash generated from operations.

Our derivative activities could result in financial losses or could reduce our income, which may adversely affect our ability to reinstate distributions to our unitholders. To the extent we have hedged a significant portion of our expected production and actual production is lower than expected or the costs of goods and services increase, our profitability would be adversely affected.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently and may in the future enter into derivative arrangements for a significant portion of our expected oil and natural gas production that could result in both realized and unrealized commodity derivative losses. As of February 25, 2016, we had hedged, through swaps, options (including collar instruments) and physical contracts, approximately 77% of our expected 2016 production.

The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. The reference prices of the derivative instruments we utilize may differ significantly from the actual oil and natural gas prices we realize in our operations. Furthermore, we have adopted a policy that requires, and our credit facility also mandates, that we enter into derivative transactions related to only a portion of our expected production volumes and, as a result, we will continue to have direct commodity price exposure on the portion of our production volumes not covered by these derivative transactions.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution in our profitability and liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

In addition, our derivative activities are subject to the following risks:

- we may be limited in receiving the full benefit of increases in oil and natural gas prices as a result of these transactions;
- a counterparty may not perform its obligation under the applicable derivative instrument or seek bankruptcy protection;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

As of February 25, 2016, our derivative counterparties were Bank of Montreal, Barclays Bank PLC, BNP Paribas, Canadian Imperial Bank of Commerce, Citibank, N.A., Citizens Bank, National Association, Comerica Bank, Credit Agricole Corporate and Investment Bank, Credit Suisse Energy LLC, Credit Suisse International, ING Capital Markets LLC, JP Morgan Chase Bank N.A., Merrill Lynch Commodities, Inc., Morgan Stanley Capital Group Inc., Royal Bank of Canada, The Bank of Nova Scotia, The Toronto-Dominion Bank, Union Bank N.A. and Wells Fargo Bank, N.A. We periodically obtain credit default swap information on our counterparties. As of December 31, 2015 and February 25, 2016, each of these financial institutions had an investment grade credit rating. Although we currently do not believe that we have a specific counterparty risk with any party, our loss could be substantial if any of these parties were to default. As of December 31, 2015, our largest derivative asset balances were with Wells Fargo Bank, N.A., Barclays Bank PLC, Credit Suisse Energy LLC and Morgan Stanley Capital Group Inc., which accounted for approximately 15%, 13%, 11% and 11% of our derivative asset balances, respectively.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

On July 21, 2010, new comprehensive financial reform legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank") was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Partnership, that participate in that market. Dodd-Frank requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing Dodd-Frank. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for, or linked to, certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. To the extent we engage in such transactions or transactions that become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception to the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, certain banking regulators and the CFTC have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from such margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, rules that require end-users to post initial or variation margin could impact our liquidity and reduce cash available for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows.

In addition, Dodd-Frank was intended, in part, to reduce the volatility of oil and gas prices. To the extent oil and gas prices are unhedged, our revenues could be adversely affected if a consequence of Dodd-Frank and implementing regulations is to lower commodity prices.

The full impact of Dodd-Frank and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. Dodd-Frank and any new regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of some derivatives to protect against risks that we encounter or reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make distributions to our unitholders. Any of these consequences could have a material, adverse effect on us, our financial condition, our results of operations and our ability to make distributions to our unitholders. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations on us is uncertain.

Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves.

It is not possible to measure underground accumulations of oil or natural gas in an exact way. Oil and gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs. Our independent reserve engineers do not independently verify the accuracy and completeness of information and data furnished by us. In estimating our level of oil and natural gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

- future oil and natural gas prices;
- production levels;
- capital expenditures;
- operating and development costs;
- the effects of regulation;
- the accuracy and reliability of the underlying engineering and geologic data; and
- the availability of funds.

If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly. For example, if the SEC prices used for our December 31, 2015 reserve report had been 10% less per Bbl and 10% less per MMBtu, respectively, then the standardized measure of our estimated proved reserves as of December 31, 2015 would have decreased by $0.4 billion, from $1.3 billion, to $0.9 billion.

Our standardized measure is calculated using unhedged oil prices and is determined in accordance with SEC rules and regulations. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual drilling and production.

The reserve estimates we make for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates and the timing of development expenditures.

The present value of future net cash flows from our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil and natural gas reserves. We base the current market value of estimated proved reserves on prices and costs in effect on the day of the estimate. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- the actual prices we receive for oil and natural gas;
- our actual operating costs in producing oil and natural gas;
- the amount and timing of actual production;
- the amount and timing of our capital expenditures;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows in compliance with the FASB Accounting Standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Our actual production could differ materially from our forecasts.

From time to time, we provide forecasts of expected quantities of future oil and gas production. These forecasts are based on a number of estimates, including expectations of production from existing wells. In addition, our forecasts assume that none of the risks associated with our oil and gas operations summarized in this Item 1A occur, such as facility or equipment malfunctions, adverse weather effects, or significant declines in commodity prices or material increases in costs, which could make certain production uneconomical.

In 2015, we depended on two customers for a substantial amount of our sales. If these customers reduce the volumes of oil and natural gas that they purchase from us, our revenue and cash available for distribution will decline to the extent we are not able to find new customers for our production. In addition, if the parties to our purchase contracts default on these contracts, we could be materially and adversely affected.

In 2015, two customers accounted for approximately 36% of our net sales revenues. If these customers reduce the volumes of oil and natural gas that they purchase from us and we are not able to find new customers for our production, our revenue and cash available for distribution will decline. In 2015, Shell Trading accounted for approximately 24% of our net sales revenues and Plains Marketing accounted for approximately 12% of our net sales revenues.

Natural gas purchase contracts account for a significant portion of revenues relating to our Michigan, Indiana and Kentucky properties. We cannot assure you that the other parties to these contracts will continue to perform under the contracts. If the other parties were to default after taking delivery of our natural gas, it could have a material adverse effect on our cash flows for the period in which the default occurred. A default by the other parties prior to taking delivery of our natural gas could also have a material adverse effect on our cash flows for the period in which the default occurred depending on the prevailing market prices of natural gas at the time compared to the contractual prices.

We have limited control over the activities on properties we do not operate.

On a net production basis, we operated approximately 69% of our production in 2015. We have limited ability to influence or control the operation or future development of the non-operated properties in which we have interests or the amount of capital expenditures that we are required to fund for their operation. The success and timing of drilling development or production activities on properties operated by others depend upon a number of factors that are outside of our control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants, and selection of technology. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns on capital or lead to unexpected future costs.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are a variety of operating risks inherent in our wells, gathering systems, pipelines and other facilities, such as leaks, explosions, fires, mechanical problems and natural disasters including earthquakes and tsunamis, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial revenue losses. The location of our wells, gathering systems, pipelines and other facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

We currently possess property and general liability insurance at levels that we believe are appropriate; however, we are not fully insured for these items and insurance against all operational risk is not available to us. We are not fully insured against all risks, including drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Changes in the insurance markets after natural disasters and terrorist attacks have made it more difficult for us to obtain certain types of coverage. There can be no assurance that we will be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes or that the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to you.

If third party pipelines and other facilities interconnected to our wells and gathering and processing facilities become partially or fully unavailable to transport natural gas, oil or NGLs, our revenues and cash available for distribution could be adversely affected.

We depend upon third party pipelines and other facilities that provide delivery options to and from some of our wells and gathering and processing facilities. Since we do not own or operate these pipelines or other facilities, their continuing operation in their current manner is not within our control. If any of these third party pipelines and other facilities become partially or fully unavailable to transport natural gas, oil or NGLs, or if the gas quality specifications for the natural gas gathering or transportation pipelines or facilities change so as to restrict our ability to transport natural gas on those pipelines or facilities, our revenues and cash available for distribution could be adversely affected.

For example, in Florida, there are a limited number of alternative methods of transportation for our production, and substantially all of our oil production is transported by pipelines, trucks and barges owned by third parties. The inability or unwillingness of these parties to provide transportation services for a reasonable fee could result in us having to find transportation alternatives, increased transportation costs, or involuntary curtailment of our oil production in Florida, which could have a negative impact on our future consolidated financial position, results of operations or cash flows.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas exploration, production, gathering and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws, including tax laws, and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For example, in California, there have been proposals at the legislative and executive levels in the past for tax increases which have included a severance tax as high as 12.5% on all oil production in California. Although the proposals have not passed the California Legislature, the State of California could impose a severance tax on oil in the future. We have significant oil production in California and while we cannot predict the impact of such a tax without having more specifics, the imposition of such a tax could have severe negative impacts on both our willingness and ability to incur capital expenditures in California to increase production, could severely reduce or completely eliminate our California profit margins and would result in lower oil production in our California properties due to the need to shut-in wells and facilities made uneconomic either immediately or at an earlier time than would have previously been the case.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the crude oil and natural gas we produce.

In response to findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis. Recently, in December 2015, the EPA finalized rules that added new sources to the scope of the greenhouse gases monitoring and reporting rule. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. In addition, in August 2015, the EPA announced proposed rules that would establish new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities, as part of an overall effort to reduce methane emissions by up to 45 percent by 2025. These new and proposed rules could result in increased compliance costs for the Partnership.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and many states have already taken legal measures to reduce emissions of greenhouse gases primarily through the implementation of state and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

California has been one of the leading states in adopting greenhouse gas emission reduction requirements, and has implemented a cap and trade program as well as mandates for renewable fuels sources. California's cap and trade program requires us to report our greenhouse gas emissions and essentially sets maximum limits or caps on total emissions of greenhouse gases from all industrial sectors that are or become subject to the program. This includes the oil and natural gas extraction sector of which we are a part. Our main sources of greenhouse gas emissions for our Southern California oil and gas operations are primarily attributable to emissions from internal combustion engines powering generators to produce electricity, flares for the disposal of excess field gas, and fugitive emission from equipment such as tanks and components. Under the California program, the cap declines annually from 2013 through 2020. We will be required to obtain authorizations for each metric ton of greenhouse gases that we emit, either in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. A portion of the allowance will be granted by the state, but any shortfall between the state-granted allowance and the facility's emissions will have to be addressed through the purchase of additional allowances either from the state or a third party. The availability of allowances will decline over time in accordance with the declining cap, and the cost to acquire such allowances may increase over time. However, we do not expect the cost to be material to our operations.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements, or they could promote the use of alternative fuels and thereby decrease demand for the oil and gas that we produce. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. Such climatic events could have an adverse effect on our financial condition and results of operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could cause us to incur increased costs and experience additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand, and chemicals under pressure into dense subsurface rock formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel, and in February 2014 issued guidance for such activities. The EPA has also issued final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing, and proposed in April 2015 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the Bureau of Land Management finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing activities on federal and American Indian lands. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision has not yet been issued.

At the state level, several states, including California, Texas, Oklahoma, and Wyoming, have adopted and/or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, the California Department of Conservation rules, effective July 2015, require the approval of Well Stimulation Treatment Notices before starting stimulation treatment, disclosure of the fluids used and, adoption of groundwater monitoring and water management plans. They also govern resident notifications, storage and handling of fluids and well integrity. At this time, we cannot predict the impact of these rules on the Partnership's operations; however, we do not expect any material adverse impact to result from the implementation of these rules. In addition, several local jurisdictions in California have proposed various forms of moratoria or bans on hydraulic fracturing. In some cases, these discussed measures include broad terms which, if enacted, could affect current operations. We do not believe that any current local proposal will have a material adverse effect on the Partnership as a whole.

The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and, in June 2015, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources. The EPA report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. The draft report is expected to be finalized after a public comment period and a formal review by the EPA's Science Advisory Board . Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These or future studies could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

A change in the jurisdictional characterization of our gathering assets by federal, state or local regulatory agencies or a change in policy by those agencies with respect to those assets may result in increased regulation of those assets.

Failure to comply with federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and production of, oil and natural gas could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to you. Please read Part I—Item 1 "—Business—Environmental Matters and Regulation" and "—Business—Other Regulation of the Oil and Gas Industry" for a description of the laws and regulations that affect us.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas exploration and production activities. These costs and liabilities could arise under a wide range of federal, state and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of injunctions that could require us to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

Strict, joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our ability to make distributions to you could be adversely affected. Please read Part I—Item 1 "—Business—Environmental Matters and Regulation" for more information.

Our business could be negatively impacted by security threats, including cybersecurity threats and other disruptions.

As an oil and natural gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities, essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows. Cybersecurity attacks in particular are evolving and include but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

Risks Related to Our Structure

We may issue additional limited partner interests, including Common Units and Preferred Units, without your approval, which would dilute your existing ownership interests.

We may issue an unlimited number of limited partner interests of any type, including Common Units and Preferred Units, without the approval of our unitholders, including in connection with potential acquisitions of oil and gas properties or the reduction of debt, which would dilute your existing ownership interests. For example, in October 2014, we issued 18.3 million Common Units (or approximately 15% of our outstanding Common Units immediately prior to the issuance), including 4.3 million Common Units in connection with the Antares Acquisition. In November 2014, we issued approximately 71.5 million Common Units (or approximately 52% of our outstanding Common Units immediately prior to issuance) in connection with the QRE Merger. In May 2014, we issued 8.0 million of 8.25% Series A Cumulative Redeemable Perpetual Preferred Units. In April 2015, we issued 46.7 million of 8.0% Series B Perpetual Convertible Preferred Units ("Series B Preferred Units") (or approximately 18% of our outstanding Common Units immediately prior to issuance) in a private offering. We elected to pay distributions on the Series B Preferred Units in kind by issuing additional Series B Preferred Units (or, if elected by the unitholder, by issuing Common Units in lieu of such Series B Preferred Units). As of February 25, 2016, 49.4 million Series B Preferred Units were outstanding.

The issuance of additional Common Units, Preferred Units or other equity securities may have the following effects:

- your proportionate ownership interest in us may decrease;
- the amount of cash distributed on each Common Unit may decrease;
- the relative voting strength of each previously outstanding Common Unit may be diminished;
- the market price of the Common Units may decline; and
- the ratio of taxable income to distributions may increase.

Our partnership agreement limits our General Partner's fiduciary duties to unitholders and restricts the remedies available to unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our General Partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- provides that our General Partner shall not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith, meaning it believed that the decisions were in the best interests of the Partnership;

- generally provides that affiliate transactions and resolutions of conflicts of interest not approved by the conflicts committee of the Board and not involving a vote of unitholders will not constitute a breach of our partnership agreement or of any fiduciary duty if they are on terms no less favorable to us than those generally provided to or available from unrelated third parties or are "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our General Partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us;

- provides that in resolving conflicts of interest where approval of the conflicts committee of the Board is not sought, it will be presumed that in making its decision the Board acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us challenging such approval, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption; and

- provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our General Partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

Unitholders are bound by the provisions of our partnership agreement, including the provisions described above.

Certain of the directors and officers of our General Partner, including the Vice Chairman of the Board, our Chief Executive Officer, our President and other members of our senior management, own interests in PCEC, which is managed by our subsidiary, Breitburn Management. Conflicts of interest may arise between PCEC, on the one hand, and us and our unitholders, on the other hand. Our partnership agreement limits the remedies available to you in the event you have a claim relating to conflicts of interest.

Certain of the directors and officers of our General Partner, including the Vice Chairman of the Board, our Chief Executive Officer, our President and other members of our senior management, own interests in PCEC, which is managed by our subsidiary, Breitburn Management. Conflicts of interest may arise between PCEC, on the one hand, and us and our unitholders, on the other hand. We have entered into an Omnibus Agreement with PCEC to address certain of these conflicts. However, these persons may face other conflicts between their interests in PCEC and their positions with us. These potential conflicts include, among others, the following situations:

- Our General Partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, repayments of indebtedness, issuances of additional partnership securities, cash reserves and expenses. Although we have entered into an Omnibus Agreement with PCEC, which addresses the rights of the parties relating to potential business opportunities, conflicts of interest may still arise with respect to the pursuit of such business opportunities. We have agreed in the Omnibus Agreement that PCEC and its affiliates will have a preferential right to acquire any third party upstream oil and natural gas properties that are estimated to contain less than 70% proved developed reserves.

- Currently and historically some officers of our General Partner and many employees of Breitburn Management have also devoted time to the management of PCEC. This arrangement will continue under the Third Amended and Restated Administrative Services Agreement (as amended, the "Administrative Services Agreement") and this will continue to result in material competition for the time and effort of the officers of our General Partner and employees of Breitburn Management who provide services to PCEC and who are officers and directors of the sole member of the general partner of PCEC. If the officers of our General Partner and the employees of Breitburn Management do not devote sufficient attention to the management and operation of our business, our financial results could suffer and our ability to make distributions to our unitholders could be reduced.

On February 5, 2016, PCEC provided written notice to Breitburn Management of its intention to terminate the Administrative Services Agreement effective as of June 30, 2016.

See "Breitburn Management" in Part II—Item 7 "—Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report for a discussion of PCEC.

Our partnership agreement limits the liability and reduces the fiduciary duties of our General Partner and its directors and officers, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing Common Units, unitholders will be deemed to have consented to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our Common Units.

Our partnership agreement restricts unitholders' voting rights by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the Board, cannot vote on any matter. In addition, solely with respect to the election of directors, our partnership agreement provides that (x) our General Partner and the Partnership will not be entitled to vote their units, if any, and (y) if at any time any person or group beneficially owns 20% or more of the outstanding Partnership securities of any class then outstanding and otherwise entitled to vote, then all Partnership securities owned by such person or group in excess of 20% of the outstanding Partnership securities of the applicable class may not be voted, and in each case, the foregoing units will not be counted when calculating the required votes for such matter and will not be deemed to be outstanding for purposes of determining a quorum for such meeting. Such Common Units will not be treated as a separate class of Partnership securities for purposes of our partnership agreement. Notwithstanding the foregoing, the Board may, by action specifically referencing votes for the election of directors, determine that the limitation set forth in clause (y) above will not apply to a specific person or group. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting unitholders' ability to influence the manner or direction of management.

Our partnership agreement has provisions that discourage takeovers.

Certain provisions of our partnership agreement may have the effect of delaying or preventing a change in control. Our directors are elected to staggered terms. The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove our General Partner. The provisions contained in our partnership agreement, alone or in combination with each other, may discourage transactions involving actual or potential changes of control.

Unitholders who are not "Eligible Holders" will not be entitled to receive distributions on or allocations of income or loss on their Common Units, and their Common Units will be subject to redemption.

In order to comply with U.S. laws with respect to the ownership of interests in oil and gas leases on federal lands, we have adopted certain requirements regarding those investors who may own our Common Units. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in oil and gas leases on federal lands. As of the date hereof, Eligible Holder means: (1) a citizen of the United States; (2) a corporation organized under the laws of the United States or of any state thereof; or (3) an association of United States citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if such association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof. For the avoidance of doubt, onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof and only for so long as the alien is not from a country that the United States federal government regards as denying similar privileges to citizens or corporations of the United States. Unitholders who are not persons or entities who meet the requirements to be an Eligible Holder will not be entitled to receive distributions or allocations of income and loss on their units and they run the risk of having their units redeemed by us at the lower of their purchase price cost or the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our General Partner.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to make distributions to you.

We are a partnership holding company and our operating subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations.

Unitholders may not have limited liability if a court finds that unitholder action constitutes participation in control of our business.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could have unlimited liability for our obligations if a court or government agency determined that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or

- your right to act with other unitholders to elect the directors of our General Partner, to remove or replace our General Partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted participation in "control" of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of Common Units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the Partnership that are known to such purchaser of units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then the value of our units may be substantially reduced.

A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a "qualifying income" requirement. Based on our current operations we believe that we satisfy the qualifying income requirement and will be treated as a partnership. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and would likely pay state income tax at varying rates. Any distributions to you would generally be taxed again as corporate distributions and no income, gains, losses, or deductions would flow through to you. Because a tax would be imposed on us as a corporation, our treatment as a corporation may result in a substantial reduction in the value of our units.

At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such tax on us by any such state may result in a substantial reduction in the value of our units.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama Administration's budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships' earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama Administration's proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the IRS, on May 5, 2015, issued proposed regulations concerning the activities that give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. We do not believe the proposed regulations affect our ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our units.

If the IRS contests the federal income tax positions we take, the market for our units may be adversely impacted, and the cost of any IRS contest may substantially reduce the value of our units. Recently enacted legislation alters the procedures for assessing and collecting taxes due for taxable years beginning after December 31, 2017, in a manner that could substantially reduce the value of our units.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our General Partner because the costs may substantially reduce the value of our units.

Recently enacted legislation applicable to us for taxable years beginning after December 31, 2017 alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as the result of audit adjustments, the value of our units may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

Future legislation may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and development. Additionally, future federal or state legislation may impose new or increased taxes or fees on oil and natural gas extraction.

Potential legislation, if enacted into law, could make significant changes to U.S. federal and state income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal and state income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively impact the value of an investment in our units. Additionally, legislation could be enacted that increases the taxes states impose on oil and natural gas extraction. Moreover, President Obama has proposed, as part of the Budget of the United States Government for Fiscal Year 2017, to impose an "oil fee" of $10.25 on a per barrel equivalent of crude oil. This fee would be collected on domestically produced and imported petroleum products. The fee would be phased in evenly over five years, beginning October 1, 2016. The adoption of this, or similar proposals, could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil.

You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Because you will be treated as a partner to whom we will allocate a share of our taxable income which could be different than the cash we distribute, you may be required to pay federal income taxes and, in some cases, state and local income taxes on your share of our taxable income, even if you receive no cash distribution from us. You may not receive a cash distribution from us equal to your share of our taxable income or even equal to the actual tax liability resulting from that income.

We anticipate engaging in transactions to reduce the Partnership's indebtedness and manage our liquidity that generate taxable income (including cancellation of indebtedness income) allocable to unitholders, and income tax liabilities arising therefrom may exceed the value of your investment in the Partnership.

In response to current market conditions, we anticipate engaging in transactions to de-lever the Partnership and manage our liquidity that would result in income and gain to our unitholders without a corresponding cash distribution. For example, we may sell assets and use the proceeds to repay existing debt or fund capital expenditures, in which case, you would be allocated taxable income and gain resulting from the sale without receiving a cash distribution or may exceed the amount of any distribution we might pay in any given year. Further, we anticipate pursuing opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications and extinguishment of our existing debt that would result in "cancellation of indebtedness income" (also referred to as "COD income") being allocated to our unitholders as ordinary taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed the current value of your investment in the Partnership.

Entities taxed as corporations may have net operating losses to offset COD income or may otherwise qualify for an exception to the recognition of COD income, such as the bankruptcy or insolvency exceptions. In the case of partnerships like ours, however, these exceptions are not available to the partnership and are only available to a unitholder if the unitholder itself is insolvent or in bankruptcy. As a result, these exceptions generally would not apply to prevent the taxation of COD income allocated to our unitholders. The ultimate tax effect of any such income allocations will depend on the unitholder's individual tax position, including, for example, the availability of any suspended passive losses that may offset some portion of the allocable COD income. The suspended passive losses available to offset COD income will increase the longer a unitholder has owned our units. Unitholders may, however, be allocated substantial amounts of ordinary income subject to taxation, without any ability to offset such allocated income against any capital losses attributable to the unitholder's ultimate disposition of its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences to them of COD income.

Tax gain or loss on the disposition of our units could be more or less than expected.

If you sell your units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those units. Because distributions to you in excess of your allocable share of our net taxable income decrease your tax basis in your units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. In addition, because the amount realized will include your share of our nonrecourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

A substantial portion of the amount realized from the sale of your units, whether or not representing gain, may be taxed as ordinary income to you due to potential recapture items, including depreciation recapture. Thus, you may recognize both ordinary income and capital loss from the sale of your units if the amount realized on a sale of your units is less than your adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which you sell your units, you may recognize ordinary income from our allocations of income and gain to you prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in units by tax-exempt entities, including individual retirement accounts ("IRAs"), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Our partnership agreement generally prohibits non-U.S. persons from owning our units. However, if non-U.S. persons own our units, distributions to such non-U.S. persons will be subject to withholding taxes imposed at the highest tax rate applicable to such non-U.S. person, and each non-U.S. person will be required to file U.S. federal income tax returns and pay tax on its share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our units.

We treat each purchaser of our Common Units as having the same tax benefits without regard to the Common Units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of the Common Units.

Due to a number of factors, including our inability to match transferors and transferees of Common Units, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of Common Units and could have a negative impact on the value of our Common Units or result in audit adjustments to our unitholders' tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our Common Units each month based upon the ownership of our Common Units on the first day of each month, instead of on the basis of the date a particular Common Unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our Common Units each month based upon the ownership of our Common Units on the first day of each month, instead of on the basis of the date a particular Common Unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The U.S. Treasury Department recently adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize the use of the proration method we have adopted for our 2015 taxable year and may not specifically authorize all aspects of our proration method thereafter. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among unitholders.

A unitholder whose units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of units) may be considered to have disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have constructively terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest are counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders receiving two Schedules K-1) for one calendar year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine in a timely manner that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, the partnership may be permitted to provide only a single Schedule K-1 to its unitholders for the tax year in which the termination occurs.

For example, in 2015 as a result of normal trading activity by our unitholders, greater than 50% of our Common Units traded within a twelve month period and caused a technical termination of the Partnership for federal income tax purposes. This technical termination required the closing of our taxable year for all unitholders on March 31, 2015 and brought about two taxable periods for 2015: January 1, 2015 to March 31, 2015 and March 31, 2015 to December 31, 2015. We were required to file two federal tax returns for the two short periods during the 2015 tax year.

You may be subject to state and local taxes and return filing requirements in jurisdictions where you do not live as a result of investing in our units.

In addition to federal income taxes, you may be subject to return filing requirements and other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. Further, you may be subject to penalties for failure to comply with those return filing requirements. We currently conduct business and own assets in California, Colorado, Florida, Indiana, Kentucky, Michigan, Texas, Utah and Wyoming. Each of these states other than Florida, Texas and Wyoming currently imposes a personal income tax on individuals, and all of these states impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may conduct business or own assets in additional states that impose a personal income tax. It is the responsibility of each unitholder to file all U.S. federal, state and local tax returns.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

The information required to be disclosed in this Item 2 is incorporated herein by reference to Part I—Item 1 "—Business."

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 material pending legal proceedings or know of any such procedures contemplated by government authorities. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

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 trade on the NASDAQ Global Select Market under the symbol "BBEP." As of December 31, 2015, based upon information received from our transfer agent and brokers and nominees, we had approximately 96,927 common unitholders of record.

The following table sets forth high and low intraday sales prices per Common Unit for the periods indicated. The last reported sales price for our Common Units on February 25, 2016 was $0.53 per unit.

	Unit Price Range	
Quarter	**High**	**Low**
2015		
Fourth Quarter	$ 2.95	$ 0.47
Third Quarter	$ 4.76	$ 1.95
Second Quarter	$ 6.87	$ 4.55
First Quarter	$ 9.40	$ 4.55
2014		
Fourth Quarter	$ 20.73	$ 6.46
Third Quarter	$ 23.15	$ 19.83
Second Quarter	$ 22.30	$ 19.65
First Quarter	$ 21.36	$ 19.1

Distributions on Common Units

On November 30, 2015, we elected to suspend distributions on our Common Units effective with the third monthly payment of the distribution relating to the third quarter of 2015. Given the impact that low commodity prices has had on our cash flows and operations, we do not expect to reinstate distributions in 2016. Our credit agreement restricts us from making cash distributions unless, after giving effect to such distribution, we remain in compliance with all terms and conditions of our credit facility. The indenture governing our Senior Secured Notes also restricts our ability to make distributions to unitholders. We are not currently restricted from paying distributions under our credit facility or the terms governing the Senior Secured Notes. See Item 7 "—Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facility" and Note 9 to the consolidated financial statements in this report.

In October 2013, we changed our distribution payment policy from a quarterly payment schedule to a monthly payment schedule beginning with the distributions relating to the fourth quarter of 2013. For the quarters for which we declare a distribution, we expect that the distribution for the quarter will be made in three equal monthly payments within 17, 45 and 75 days following the end of each quarter to unitholders of record on the applicable record date. Prior to the distribution policy change, for the quarters for which we declared a distribution, distributions of available cash were made within 45 days after the end of the quarter to unitholders of record on the applicable record date.

Available cash, as defined in our partnership agreement, generally is all cash on hand, including cash from borrowings, at the end of the quarter after the payment of our expenses and the establishment of reserves for future capital expenditures and operational needs.

The following table provides a summary of Common Unit distributions related to and declared during the years ended December 31, 2015 and 2014:

Thousands of dollars, except per unit amounts	**Cash Distributions**			
Period	**Total (a)**	**Per Common Unit**	**Declaration Date**	**Payment Date**
2015				
December 2015	(b)	—	—	—
November 2015	(b)	—	—	—
October 2015	(b)	—	—	—
September 2015	(b)	—	—	—
August 2015	$ 8,827	$ 0.04166	10/30/2015	11/13/2015
July 2015	$ 8,825	$ 0.04166	10/1/2015	10/16/2015
June 2015	$ 8,823	$ 0.04166	8/27/2015	9/11/2015
May 2015	$ 8,820	$ 0.04166	7/31/2015	8/14/2015
April 2015	$ 8,818	$ 0.04166	7/1/2015	7/17/2015
March 2015	$ 8,816	$ 0.04166	5/28/2015	6/12/2015
February 2015	$ 8,790	$ 0.04166	4/24/2015	5/15/2015
January 2015	$ 8,787	$ 0.04166	4/1/2015	4/17/2015
2014				
December 2014	$ 17,570	$ 0.0833	2/24/2015	3/13/2015
November 2014	$ 17,571	$ 0.0833	1/27/2015	2/13/2015
October 2014	$ 17,571	$ 0.0833	1/2/2015	1/16/2015
September 2014	$ 36,447	$ 0.1733	11/24/2014	12/12/2014
August 2014	$ 23,245	$ 0.1675	10/29/2014	11/14/2014
July 2014	$ 22,524	$ 0.1675	10/1/2014	10/16/2014
June 2014	$ 20,179	$ 0.1675	8/25/2014	9/11/2014
May 2014	$ 20,179	$ 0.1675	7/30/2014	8/14/2014
April 2014	$ 20,179	$ 0.1675	7/1/2014	7/16/2014
March 2014	$ 19,836	$ 0.1658	5/27/2014	6/12/2014
February 2014	$ 19,836	$ 0.1658	4/24/2014	5/14/2014
January 2014	$ 19,815	$ 0.1658	4/1/2014	4/16/2014
2013				
December 2013	$ 19,573	$ 0.1642	2/26/2014	3/14/2014
November 2013	$ 19,573	$ 0.1642	1/30/2014	2/14/2014
October 2013	$ 19,573	$ 0.1642	1/2/2014	1/16/2014

(a) Does not include distribution equivalents paid under our long-term incentive plans.

(b) Effective November 30, 2015, distributions on Common units were suspended by the Board of Directors, thus there were no Common unit distributions attributable to the fourth quarter 2015 including the third monthly payment of the distribution attributable to the third quarter.

Distributions on Preferred Units

On April 8, 2015, we issued in a private offering $350 million of 8.0% Series B Perpetual Convertible Preferred Units ("Series B Preferred Units") to EIG Redwood Equity Aggregator, LP ("EIG Equity"), ACMO BBEP Corp. ("ACMO") and certain other purchasers at an issue price of $7.50 per unit. The Series B Preferred Units rank senior to the Common Units and on parity with the Series A Preferred Units (as defined below) with respect to the payment of current distributions. We have the election through April 2018 to pay our Series B Preferred Unit distribution in kind by issuing additional Series B Preferred units (or, if elected by the unitholder, by issuing Common Units in lieu of such Series B Preferred units) in lieu of cash and we have paid the distributions in kind since the Series B Preferred Units were issued. In 2015, we declared distributions on our Series B Preferred Units of 0.054883 paid in kind units per Series B Preferred Unit, in the form of 2.2 million Series B Preferred Units and 0.4 million Common Units.

On May 21, 2014, we sold 8.0 million 8.25% Series A Cumulative Redeemable Perpetual Preferred Units ("Series A Preferred Units") in a public offering at a price of $25.00 per Series A Preferred Unit. The Series A Preferred Units rank senior to our Common Units with respect to the payment of current distributions. Distributions on Series A Preferred Units are cumulative from the date of original issue and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by our Board out of legally available funds for such purpose. We pay cumulative distributions in cash on the Series A Preferred Units on a monthly basis at a monthly rate of $0.171875 per Series A Preferred Unit.

Equity Compensation Plan Information

See Part III—Item 12 "—Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" for information regarding securities authorized for issuance under equity compensation plans.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

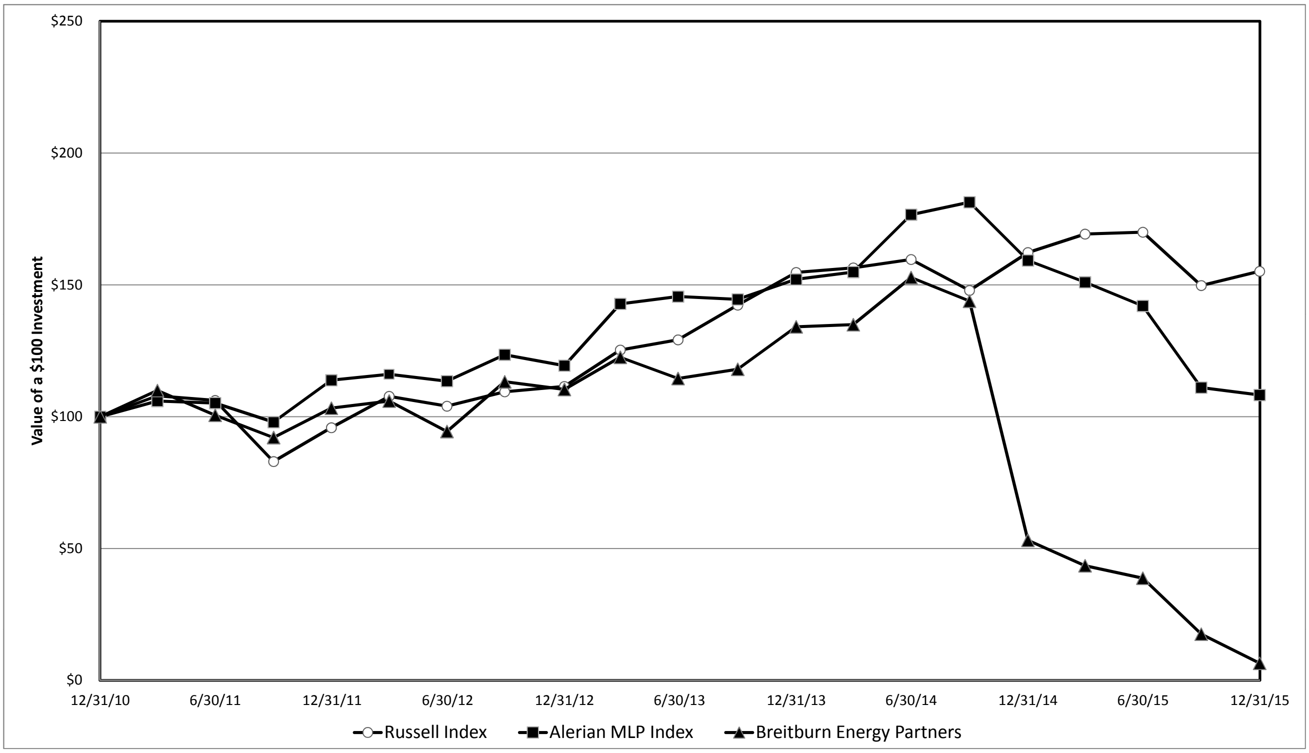
Purchases of Equity Securities by the Issuer and Affiliated Purchasers

There were no purchases of our Common Units by us or any affiliated purchasers during the fourth quarter of 2015.

Common Unit Performance Graph

The graph below compares our cumulative total unitholder return on our Common Units over the five years ended December 31, 2015 with the cumulative total returns over the same period of the Russell 2000 index and the Alerian MLP index. The graph assumes that the value of the investment in our Common Units, in the Russell 2000 index and in the Alerian MLP index was $100 on December 31, 2010. Cumulative return is computed assuming reinvestment of dividends.

Comparison of Cumulative Total Return among the Partnership, the Russell 2000 Index and the Alerian MLP Index



The information in this report appearing under the heading “Common Unit Performance Graph” is being furnished pursuant to Item 2.01(e) of Regulation S-K and shall not be deemed to be “soliciting material” or to be “filed” with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 2.01(e) of Regulation S-K, or to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended.

Item 6. Selected Financial Data.

We have derived the selected financial data set forth in the following table for each of the years ended December 31, 2015, 2014 and 2013, with the exception of consolidated balance sheet data for the year ended December 31, 2013, from our audited consolidated financial statements appearing elsewhere in this report. We derived the financial data for the years ended December 31, 2012 and 2011, as well as consolidated balance sheet data for the year ended December 31, 2013, from our prior year audited consolidated financial statements, which are not included in this report.

In 2015, we completed the acquisition on March 31, 2015 of certain CO_2 producing properties located in Harding County, New Mexico for a purchase price of $70.5 million.

On October 24, 2014, we completed the Antares Acquisition for 4.3 million Common Units and $50.0 million in cash. On November 19, 2014 we closed the QRE Merger in exchange for approximately 71.5 million Common Units and $350 million in cash, and the assumption of approximately $1.1 billion of QRE debt.

On July 15, 2013, we completed the Whiting Acquisition for approximately $845 million. We also completed the acquisition of additional interests in the Oklahoma Panhandle for an additional $30 million on July 15, 2013. On December 30, 2013, we completed the 2013 Permian Basin Acquisitions from CrownRock, L.P. for approximately $282 million. We also completed the acquisition of additional interests in certain of the acquired assets in the Permian Basin from other sellers for an additional $20 million in December 2013.

In 2012, we completed the NiMin Acquisition on June 28, 2012 for approximately $95 million. On July 2, 2012, we completed acquisitions of oil and natural gas properties located in the Permian Basin in Texas from Element Petroleum, LP and CrownRock, L.P. for approximately $148 million and $70 million, respectively. On November 30, 2012, we completed the AEO Acquisition for approximately $38 million in cash and approximately 3 million Common Units. On December 28, 2012, we completed the acquisition of oil and natural gas properties located in the Permian Basin in Texas from CrownRock, L.P., Lynden USA Inc. and Piedra Energy I, LLC for approximately $164 million, $25 million and $10 million, respectively. Effective April 1, 2012, our ownership interest in properties at two California fields decreased from approximately 95% to approximately 62%. We completed the Greasewood Acquisition on July 28, 2011 for approximately $57 million and the Cabot Acquisition on October 6, 2011 for approximately $281 million.

See Note 3 to the consolidated financial statements in this report for further details about our acquisitions in 2015, 2014 and 2013.

You should read the following selected financial data in conjunction with Part II—Item 7 "—Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes in this report.

	Year Ended December 31,				
Thousands of dollars, except per unit amounts	**2015**	**2014**	**2013**	**2012**	**2011**
Statement of Operations Data:					
Oil, natural gas and NGL sales	$ 645,272	$ 855,820	$ 660,665	$ 413,867	$ 394,393
Gain (loss) on commodity derivative instruments, net	438,614	566,533	(29,182)	5,580	81,667
Other revenue, net	24,829	7,616	3,175	3,548	4,310
Total revenue	1,108,715	1,429,969	634,658	422,995	480,370
Impairment of oil and natural gas properties	2,377,615	149,000	54,373	12,313	648
Impairment of goodwill	95,947	—	—	—	—
Operating (loss) income	(2,376,582)	545,967	44,276	21,700	153,809
Net (loss) income	(2,583,013)	421,316	(43,671)	(40,739)	110,698
Less: Net income (loss) attributable to noncontrolling interest	326	(17)	—	62	201
Net (loss) income attributable to the partnership	$(2,583,339)	$ 421,333	$ (43,671)	$ (40,801)	$ 110,497
Basic net (loss) income per unit	$ (12.39)	$ 3.04	$ (0.43)	$ (0.56)	$ 1.80
Diluted net (loss) income per unit	$ (12.39)	$ 3.02	$ (0.43)	$ (0.56)	$ 1.79
Cash Flow Data:					
Net cash provided by operating activities	$ 436,705	$ 360,173	$ 257,166	$ 191,782	$ 128,543
Net cash used in investing activities	(274,003)	(837,004)	(1,465,805)	(697,159)	(414,573)
Net cash (used in) provided by financing activities	(164,866)	487,001	1,206,590	504,556	287,728
Balance Sheet Data (at period end):					
Cash	$ 10,464	$ 12,628	$ 2,458	$ 4,507	$ 5,328
Other current assets	577,863	588,080	114,604	109,158	167,492
Net property, plant and equipment	3,932,882	6,454,201	3,915,376	2,711,893	2,072,759
Other assets	351,203	583,425	163,844	89,936	85,270
Total assets	$ 4,872,412	$ 7,638,334	$ 4,196,282	$ 2,915,494	$ 2,330,849
Current liabilities	$ 318,006	$ 361,556	$ 182,889	$ 115,240	$ 89,889
Long-term debt	2,867,157	3,247,160	1,889,675	1,100,696	820,613
Other long-term liabilities	281,354	263,442	133,898	110,022	93,133
Partners' equity	1,398,571	3,759,291	1,989,820	1,589,536	1,326,764
Noncontrolling interest	7,324	6,885	—	—	450
Total liabilities and partners' equity	$ 4,872,412	$ 7,638,334	$ 4,196,282	$ 2,915,494	$ 2,330,849
Cash distributions declared per unit outstanding:	$ 0.3333	$ 1.7581	$ 1.9125	$ 1.8300	$ 1.6875

The following table presents a non-GAAP financial measure, "Adjusted EBITDA," which we use in our business. This measure is not calculated or presented in accordance with US GAAP.

We believe the presentation of Adjusted EBITDA provides useful information to investors to evaluate the operations of our business excluding certain items and for the reasons set forth below. Adjusted EBITDA should not be considered an alternative to net income, operating income, cash flow from operating activities or any other measure of financial performance presented in accordance with US GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

We use Adjusted EBITDA to assess:

- the financial performance of our assets, without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure;
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities; and
- the ability of our assets to generate cash sufficient to pay interest costs, pay distributions and support our indebtedness.

The following table presents a reconciliation of Adjusted EBITDA to net income (loss) attributable to the partnership and cash flows provided by operating activities, our most directly comparable US GAAP financial performance measures, for each of the periods indicated.

	Year Ended December 31,				
Thousands of dollars	2015	2014	2013	2012	2011
Reconciliation of consolidated net income (loss) to Adjusted EBITDA:					
Net (loss) income attributable to the partnership	$ (2,583,339)	$ 421,333	$ (43,671)	$ (40,801)	$ 110,497
(Gain) loss on commodity derivative instruments (a)	(438,614)	(566,533)	29,182	(5,580)	(81,667)
Commodity derivative instrument settlements (b)(c)(d)	499,985	27,825	8,083	87,605	(16,067)
Depletion, depreciation and amortization	460,047	291,709	216,495	137,252	106,855
Impairment of oil and natural gas properties	2,377,615	149,000	54,373	12,313	648
Impairment of goodwill	95,947	—	—	—	—
Interest expense, net of capitalized interest	203,027	126,960	87,067	61,206	39,165
(Gain) loss on interest rate swaps (e)	2,691	(490)	—	1,101	2,777
Settlement payments (receipts) on terminated derivatives	—	—	—	—	36,779
(Gain) loss on sale of assets	(8,864)	663	(2,015)	486	(111)
Income tax expense (benefit)	1,527	(73)	905	84	1,188
Unit based compensation	26,805	23,387	19,955	22,184	22,002
Adjusted EBITDA	$ 636,827	$ 473,781	$ 370,374	$ 275,850	$ 222,066

(a) We enter into certain derivative instrument contracts such as put options that require the payment of premiums at contract inception. Gain (loss) on commodity derivative instruments includes the reduction of premium value for derivative instruments over time. Our calculation of Adjusted EBITDA does not include premiums paid for derivative instruments at contract inception as these payments pertain to future contract settlement periods.

	2015	2014	2013	2012	2011
(b) Includes net cash settlements on derivative instruments:					
- Oil settlements received (paid) of:	$ 431,073	$ 18,230	$ (36,183)	$ 3,855	$ (70,398)
- Natural gas settlements received of:	68,912	9,595	44,266	83,750	54,331
(c) Includes premiums deferred and paid at the time of derivative contract settlements each period of:	97	657	892	—	—
(d) Excludes premiums paid at contract inception related to those derivative contracts that settled during the periods of:	6,672	8,494	4,893	859	—
(e) Includes settlements paid on interest rate derivatives including terminated interest rate derivatives of:	5,751	1,019	—	5,469	3,257

Thousands of dollars	Year Ended December 31, 2015	2014	2013	2012	2011
Reconciliation of net cash flows from operating activities to Adjusted EBITDA:					
Net cash provided by operating activities	$436,705	$357,755	$257,166	$191,782	$128,543
Increase in assets (net of liabilities) relating to operating activities	16,369	(4,057)	32,105	22,492	18,942
Interest expense, net of capitalized interest (a)	183,852	120,143	80,617	61,807	37,702
Loss on early termination of commodity derivatives	—	—	—	—	36,779
Income from equity affiliates, net	104	(178)	(55)	(487)	(210)
Incentive compensation expense	—	—	(21)	(82)	(41)
Incentive compensation paid	—	—	—	—	78
Income taxes	258	101	562	400	474
Non-controlling interest	(326)	17	—	(62)	(201)
Gain on marketable securities	(135)	—	—	—	—
Adjusted EBITDA	$636,827	$473,781	$370,374	$275,850	$222,066

(a) Includes settlement payments on interest rate swaps, and excludes amortization of debt issuance costs and net premium on senior notes.

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 the "Selected Financial Data" and the financial statements and related notes included elsewhere in this report. The following discussion contains forward-looking statements that reflect our future plans, estimates, 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 are discussed in "Risk Factors" contained in Part I—Item 1A of this report. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Statement Regarding Forward-Looking Information" in the front of this report.

Overview

We are an independent oil and gas partnership focused on the acquisition, exploitation and development of oil, NGL and natural gas properties in the United States. Our objective is to manage our oil, NGL and natural gas producing properties for the purpose of generating cash flow and making distributions to our unitholders. Our assets consist primarily of producing and non-producing oil, NGL and natural gas reserves located in the following producing areas: i) Midwest (Michigan, Indiana, and Kentucky), ii) Ark-La-Tex (Arkansas, Louisiana and East Texas), iii) the Permian Basin in Texas and New Mexico, iv) Mid-Continent (Oklahoma, Kansas and the Texas Panhandle), v) the Rockies (Wyoming and Colorado), vi) Southeast (Florida and Alabama) and vii) California.

Our core investment strategy has included the following principles:

- acquire long-lived assets with low-risk exploitation and development opportunities;
- use our technical expertise and state-of-the-art technologies to identify and implement successful exploitation techniques to optimize reserve recovery;
- reduce cash flow volatility through commodity price and interest rate derivatives; and
- maximize asset value and cash flow stability through our operating and technical expertise.

In 2015, oil and gas prices continued the rapid and substantial decline that began at the end of 2014 and that has continued into the first quarter of 2016. In response to the precipitous decline in commodity prices, we initiated a series of financial and operational actions as set forth below.

- In January 2015, we reduced our distributions to common unitholders to $1.00 per unit on an annualized basis.
- In April 2015, we raised approximately $1 billion of secured second lien notes and preferred equity, the net proceeds of which we used to repay borrowings under our credit facility, and we further reduced our distributions to common unitholders to $0.50 per unit on an annualized basis.
- In connection with the April 2015 capital raise, we negotiated a redetermination of our borrowing base to $1.8 million under our credit facility for one year, which provided stable liquidity in 2015.
- We reduced our workforce in 2015 in excess of 60 positions through a combination of a workforce reduction plan, resignations and early retirements. We expect to further reduce our workforce in 2016 in an effort to reduce our general and administrative and other personnel costs.
- We reduced our capital spending in 2015 to approximately $209 million from approximately $389 million in 2014. We are continuing that reduction and expect to spend approximately $80 million in 2016 focused primarily on drilling and rate-generating projects and CO_2 purchases that are designed to either increase or add to production or reserves.
- In November 2015, we suspended the payment of distributions on our Common Units, which preserves approximately $9 million per month in cash expenditures.

2015 Acquisitions

On March 31, 2015, we completed the acquisition of certain CO_2 producing properties located in Harding County, New Mexico, for a total purchase price of $70.5 million (the "$CO_2$ Acquisition"), which is primarily reflected in other property, plant and equipment on the consolidated balance sheet. See Note 3 to the consolidated financial statements within this report for a discussion of this acquisition.

2015 Highlights

Senior Secured Notes

On April 8, 2015, we issued $650 million of 9.25% Senior Secured Second Lien Notes due 2020 ("Senior Secured Notes") in a private offering to EIG Redwood Debt Aggregator, LP and certain other purchasers at a purchase price of 97% of the principal amount. We received approximately $606.9 million from this offering net of fees and estimated expenses, which we primarily used to repay borrowings under our credit facility. Interest on the Senior Secured Notes is payable quarterly in March, June, September and December. In connection with the offering, we entered into the First Amendment to the Third Amended and Restated Credit Agreement, to allow for the issuance of the Senior Secured Notes and to establish a revised borrowing base of $1.8 billion through April 2016, subject to limited exceptions.

Preferred Units

On April 8, 2015, we issued $350 million of 8.0% Series B Perpetual Convertible Preferred Units ("Series B Preferred Units") in a private offering to EIG Redwood Equity Aggregator, LP ("EIG Equity"), ACMO BBEP Corp. ("ACMO") and certain other purchasers at an issue price of $7.50 per unit. We received approximately $337.2 million from these offerings, net of fees and estimated expenses, which we primarily used to repay borrowings under our credit facility. The Series B Preferred Units rank senior to the Common Units and on parity with the 8.25% Series A Cumulative Redeemable Perpetual Preferred Units ("Series A Preferred Units") with respect to the payment of distributions.

Distributions on the Series B Preferred Units are cumulative from the date of original issue and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by our Board of Directors out of legally available funds for such purpose. For the first monthly distribution on April 24, 2015, we declared a distribution on the Series B Preferred Units, which we elected to pay in kind by issuing additional Series B Preferred Units (or, if elected by the unitholder, by issuing Common Units in lieu of such Series B Preferred Units) in lieu of cash of 0.008222 Series B Preferred Unit per unit, which was paid on May 15, 2015. Regular monthly distributions of 0.006666 paid-in-kind unit per Series B Preferred Unit began with the June 15, 2015 payment. During the year ended December 31, 2015, we recognized $20.8 million of accrued distributions on the Series B Preferred Units, which are included in distributions to preferred unitholders on the consolidated statements of operations.

In 2015, we declared cash distributions on the Series A Preferred Units at a monthly distribution rate of $0.171875 per unit, which is equal to an annual distribution of $2.0625 per Series A Preferred Unit. During the year ended December 31, 2015, we recognized $16.5 million of distributions that were declared on the Series A Preferred Units, which are included in distributions to preferred unitholders on the consolidated statements of operations.

Common Units

In 2015, we declared cash distributions to holders of our Common Units and our unvested restricted phantom units ("RPUs") totaling $123.2 million and $3.0 million, respectively. In response to current commodity and financial market conditions, the Board of Directors suspended distributions on Common Units effective with the third monthly payment attributable to the third quarter of 2015.

During the year ended December 31, 2015, we issued approximately 0.5 million Common Units pursuant to an Equity Distribution Agreement dated as of March 19, 2014 (the "Equity Distribution Agreement"), for net proceeds of $3.1 million. See Note 15 for a discussion of the Equity Distribution Agreement.

Capital Expenditures

In 2015, our oil and gas capital expenditures, including capitalized engineering costs and excluding expenditures to acquire properties, totaled approximately $209 million, compared with approximately $389 million in 2014. In 2015, we spent approximately $65 million in the Permian Basin, $58 million in Ark-La-Tex, $42 million in Southeast, $26 million in Mid-Continent, $14 million in California, $3 million in Midwest and $1 million in the Rockies. In the Permian Basin, we drilled and completed 23 new productive wells, three recompletions and six workovers. In California, we drilled and completed five new productive wells, four recompletions and one workover. In Mid-Continent, we drilled and completed two new productive well, zero recompletions and completed five workovers. In Florida, we performed zero recompletions and 15 workovers. In Ark-La-Tex, we drilled and completed 28 new productive wells and completed 47 workovers. In the Midwest, we drilled and completed zero new wells, two recompletions and one workover. In the Rockies, we drilled and completed two new productive wells, zero recompletions and three workovers. Primarily as a result of our 2013, 2014 and 2015 acquisitions and our capital spending, our 2015 production was 20,180 MBoe, which was 43% higher than our 2014 production.

2016 Outlook

In 2015, oil, NGL and natural gas prices exhibited significant volatility. Due to the uncertainty regarding future commodity prices, we plan to manage our operating activities and liquidity carefully. We do not expect increased production as a result of our 2016 capital program to entirely offset production declines, and expect that will result in decreases to our production, without taking into account acquisitions, divestitures or further modifications to our capital and operating plan based on price changes through 2016. We plan to continuously evaluate our operating activity in light of commodity prices and changes we are able to make to both our costs of operations and to our capital budget.

In 2015, the WTI spot price averaged approximately $48 per Bbl, compared with approximately $93 per Bbl a year earlier. During 2015, the WTI monthly average ranged from a high of $60 per Bbl in June to a monthly average low of $37 per Bbl in December. In 2014, prices ranged from a monthly average high of $106 per Bbl in June to a monthly average low of $59 per Bbl in December. As of February 16, 2016, the WTI spot price during 2016 has averaged $31 per Bbl. Historically, there has been a strong relationship between changes in NGL and crude oil prices. NGL prices are correlated to North American supply and petrochemical demands. Lower crude oil prices may not only decrease our revenues, but may also reduce the amount of crude oil that we can produce economically and therefore potentially lower our crude oil reserves.

We expect our full year 2016 oil and gas capital spending program to be approximately $80 million, including capitalized engineering costs and excluding potential acquisitions, compared with approximately $209 million in 2015. The reduction in capital expenditures reflects our outlook for 2016 performance measured against the ongoing weakness in commodity prices. We anticipate that 60% of our total capital spending will be focused on drilling and rate-generating projects and CO_2 purchases, in our core operating areas of East Texas, the Permian Basin and the Mid-Continent, that are designed to increase or add to production or reserves. We plan to drill 17 wells in Ark-La-Tex and Mid-Continent. We expect our 2016 production to be between 17.0 MMBoe and 19.7 MMBoe.

Commodity hedging remains an important part of our strategy to reduce cash flow volatility. We use swaps, collars and options for managing risk relating to commodity prices. As of February 25, 2016, we had approximately 77% of our expected 2016 production hedged, approximately 48% of our expected 2017 production hedged, approximately 10% of our 2018 production hedged, and approximately 5% of our 2019 production hedged. For 2016, we have 24.8 MBbl/d of oil and 83.0 BBtu/d of natural gas hedged at average prices of approximately $85.79 per Bbl and $3.98 per MMBtu, respectively. For 2017, we have 14.8 MBbl/d of oil and 56.1 BBtu/d of natural gas hedged at average prices of approximately $83.11 per Bbl and $3.98 per MMBtu, respectively. For 2018, we have 1.5 MBbl/d of oil and 20.4 BBtu/d of natural gas hedged at average prices of approximately $64.02 per Bbl and $3.19 per MMBtu, respectively. For 2019, we have 1.0 MBbl/d of oil and 10.0 BBtu/d of natural gas hedged at average prices of approximately $56.35 per Bbl and $3.15 per MMBtu, respectively.

Operational Focus

We use a variety of financial and operational measures to assess our performance. Among these measures are the following: volumes of oil and natural gas produced, amount of reserves replaced, realized prices, operating expenses, G&A and Adjusted EBITDA.

As of December 31, 2015, our total estimated proved reserves were 239.3 MMBoe, of which approximately 54% was oil, 8% was NGLs and 38% was natural gas. As of December 31, 2014, our total estimated proved reserves were 315.3 MMBoe, of which approximately 55% was oil, 8% was NGLs, and 37% was natural gas. Net changes to our total estimated proved reserves included negative reserve revisions of 71.5 MMBoe and 20.1 MMBoe of production, resulting in a net decrease of 76.0 MMBoe from 2014 partially offset by 14.9 MMBoe in extensions and discoveries. The reserve revisions in 2015 were primarily the result of a 44.4 MMBoe decrease in oil reserves and a 3.6 MMBoe decrease in NGL reserves, driven primarily by a decrease in oil and NGL prices and a 141.6 Bcf decrease in natural gas reserves primarily due to a decrease in natural gas prices. The unweighted average first-day-of-the-month oil and natural gas prices used to determine our total estimated proved reserves as of December 31, 2015 were $50.28 per Bbl of oil for the WTI spot price and $2.59 per MMBtu of natural gas for the Henry Hub spot price, compared to $94.99 per Bbl of oil for the WTI spot price, $101.30 per Bbl of oil for the ICE Brent spot price and $4.35 per MMBtu of natural gas for the Henry Hub spot price in 2014.

Of our total estimated proved reserves as of December 31, 2015, 21% were located in the Midwest, 20% were located in Ark-La-Tex, 19% in the Permian Basin, 13% in Mid-Continent, 11% in the Rockies, 9% in the Southeast and 7% in California. The discounted future net cash flows discounted at 10% were $314.6 million for Ark-La-Tex, $257.6 million for Permian, $215.9 million for Mid-Continent, $160.0 million for California, $140.1 million for the Rockies, $129.2 million for the Midwest and $63.5 million for the Southeast.

Our revenues and net income are sensitive to oil, NGL and natural gas prices. Our operating expenses are highly correlated to oil prices, and as oil prices rise and fall, our operating expenses will directionally rise and fall. Significant factors that will impact near-term commodity prices include global demand for oil and natural gas, political developments in oil producing countries including, without limitation, the extent to which members of OPEC and other oil exporting nations are able to manage oil supply through export quotas, and variations in key North American natural gas and refined products supply and demand indicators.

Prices for natural gas in many markets are aligned both with supply and demand conditions in their respective regional markets and with the overall U.S. market. Natural gas prices are also typically higher during the winter period when demand for heating is greatest in the U.S. Since January 2013 to February 2016, the monthly average natural gas spot prices at Henry Hub have ranged from a high of $8.15 per MMBtu in February 2014 to a low of $1.63 per MMBtu in December 2015. During 2015, the natural gas spot price at Henry Hub ranged from a high of $3.32 per MMBtu to a low of $1.63 per MMBtu, with the monthly average ranging from a high of $2.99 per MMBtu in January to a low of $1.93 per MMBtu in December, and averaged approximately $2.62 per MMBtu for the year. During 2014, the natural gas spot price at Henry Hub ranged from a high of $8.15 per MMBtu to a low of $2.74 per MMBtu, and averaged approximately $4.37 per MMBtu. As of February 16, 2016, the natural gas spot price at Henry Hub for 2016 has averaged approximately $2.22 per MMBtu.

Excluding the effect of derivatives, our average realized oil price for 2015 decreased $41.62 per Boe to $44.46 per Boe as compared to $86.08 per Boe in 2014. Including the effects of derivative instruments, our realized average oil price decreased $8.45 per Boe to $85.25 per Boe as compared to $93.70 per Boe in 2014, primarily due to a lower hedge volume. Excluding the effect of derivatives, our realized natural gas price for 2015 decreased $2.15 per Mcf to $2.67 per Mcf compared to $4.82 per Mcf in 2014. Including the effects of derivative instruments, our average realized natural gas price for 2015 decreased $0.82 per Mcf to $4.32 per Mcf as compared to $5.14 per Mcf in 2014, primarily due to a lower average hedge price.

While our commodity price risk management program is intended to reduce our exposure to commodity prices and assist with stabilizing cash flow, to the extent we have hedged a significant portion of our expected production and the cost for goods and services increases, our margins would be adversely affected.

In evaluating our production operations, we frequently monitor and assess our operating expenses per Boe produced. These measures allow us to better evaluate our operating efficiency and are used in reviewing the economic feasibility of a potential acquisition or development project.

Operating expenses are the costs incurred in the operation of producing properties. Expenses for utilities, direct labor, water injection and disposal, production taxes and materials and supplies comprise the most significant portion of our operating expenses. A majority of our operating cost components are variable and increase or decrease along with our levels of production. For example, we incur power costs in connection with various production related activities such as pumping to recover oil and gas, separation and treatment of water produced in connection with our oil and gas production and re-injection of water produced into the oil producing formation to maintain reservoir pressure. Although these costs typically vary with production volumes, they are driven not only by volumes of oil and gas produced but also volumes of water produced. Consequently, fields that have a high percentage of water production relative to oil and gas production, also known as a high water cut, will experience higher levels of power costs for each Boe produced. Certain items, however, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities result in increased expenses in periods during which they are performed. Our operating expenses are highly correlated to oil prices, and we can experience upward pressure on material and service costs depending on how oil prices change. These costs include specific expenditures such as lease fuel, electricity, drilling services and severance and property taxes. Pre-tax lease operating expenses, including processing fees, were $19.02 per Boe in 2015 and $20.65 per Boe in 2014.

Production taxes vary by state. All states in which we operate impose ad valorem taxes on our oil and gas properties. Various states regulate the drilling for, and the production, gathering and sale of, oil, NGLs and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Currently, Alabama, Arkansas, Florida, Indiana, Kansas, Kentucky, Louisiana, Michigan, New Mexico, Oklahoma, Texas, and Wyoming impose severance taxes on producers at rates ranging from 1% to 13% of the value of the gross product extracted. Wyoming and Oklahoma wells that reside on Native American or federal land are subject to an additional tax of 8.5% and 8.0%, respectively. Florida sulfur sales are subject to a tax of $6.13 per long ton. California does not currently impose a severance tax; rather it imposes an ad valorem tax based in large part on the value of the mineral interests in place. See Part I—Item 1A "—Risk Factors" — "Risks Related to Our Business — We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations" in this report.

We recorded non-cash oil and natural gas asset impairment charges of $2.4 billion during 2015, and non-cash oil and natural gas asset impairments of $149.0 million during 2014. A further decline in future commodity prices could result in additional oil and gas impairment charges. The cash flow model that we use to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future production, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward commodity prices alone could potentially result in impairment.

Adjusted EBITDA was $636.8 million in 2015 and $473.8 million in 2014. The increase in Adjusted EBITDA was primarily due to higher commodity derivative instrument settlement receipts and a full year of operating results from the properties acquired in the 2014 QRE Merger partially offset by the decline in commodity prices.

Breitburn Management

Breitburn Management operates our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. Our employees, including our executives, are employees of Breitburn Management. Breitburn Management also operates the assets of PCEC, our Predecessor. In addition to a monthly fee for indirect expenses, Breitburn Management charges PCEC for all direct expenses including incentive plan costs and direct payroll and administrative costs related to PCEC's properties and operations.

On February 5, 2016, PCEC provided written notice to Breitburn Management of its intention to terminate the Administrative Services Agreement effective as of June 30, 2016.

For information on potential conflicts between us and PCEC, see Part I—Item 1A "—Risk Factors"— "Risks Related to Our Structure — Certain of the directors and officers of our General Partner, including the Vice Chairman of our Board, our Chief Executive Officer, our President and other members of our senior management, own interests in PCEC, which is managed by our subsidiary, Breitburn Management. Conflicts of interest may arise between PCEC, on the one hand, and us and our unitholders, on the other hand. Our partnership agreement limits the remedies available to you in the event you have a claim relating to conflicts of interest."

See Note 5 to the consolidated financial statements in this report for more information regarding our relationship with Breitburn Management and PCEC.

Results of Operations

The table below summarizes certain of the results of operations and period-to-period comparisons attributable to our operations for the periods indicated. These results are presented for illustrative purposes only and are not indicative of our future results. The data reflect our results as they are presented in our consolidated financial statements.

	Year Ended December 31,			Increase / decrease %	
Thousands of dollars, except as indicated	**2015**	**2014**	**2013**	**2015-2014**	**2014-2013**
Total production (MBoe) (a)	20,180	14,114	10,983	43 %	29 %
Oil (MBbl)	11,248	7,931	5,651	42 %	40 %
NGLs (MBbl)	1,953	1,157	640	69 %	81 %
Natural gas (MMcf)	41,876	30,159	28,156	39 %	7 %
Average daily production (Boe/d)	55,288	38,670	30,091	43 %	29 %
Sales volumes (MBoe)	20,219	13,956	10,988	45 %	27 %
Average realized sales price (per Boe) (b) (c)	$ 31.80	$ 61.30	$ 60.05	(48)%	2 %
Oil (per Bbl) (c) (d)	44.46	86.08	93.67	(48)%	(8)%
NGLs (per Bbl)	15.02	35.46	35.25	(58)%	1 %
Natural gas (per Mcf)	2.67	4.82	3.82	(45)%	26 %
Oil sales	$ 504,035	$ 669,355	$ 530,625	(25)%	26 %
NGL sales	29,336	41,031	22,558	(29)%	82 %
Natural gas sales	111,901	145,434	107,482	(23)%	35 %
Gain (loss) on commodity derivative instruments	438,614	566,533	(29,182)	(23)%	n/a
Other revenues, net	24,829	7,616	3,175	n/a	n/a
Total revenues	1,108,715	1,429,969	634,658	(22)%	125 %
Lease operating expenses including processing fees	383,827	291,395	216,275	32 %	35 %
Production and property taxes (e)	51,174	62,071	46,220	(18)%	34 %
Total lease operating expenses	435,001	353,466	262,495	23 %	35 %
Purchases and other operating costs	3,056	725	1,322	n/a	(45)%
Salt water disposal costs	14,687	2,168	—	— %	n/a
Change in inventory	2,445	(678)	(995)	n/a	(32)%
Total operating costs	$ 455,189	$ 355,681	$ 262,822	28 %	35 %
Lease operating expenses before taxes per Boe (f)	$ 19.02	$ 20.65	$ 19.69	(8)%	5 %
Production and property taxes per Boe	2.54	4.40	4.21	(42)%	5 %
Total lease operating expenses per Boe	$ 21.56	$ 25.05	$ 23.90	(14)%	5 %
Depletion, depreciation and amortization	$ 460,047	$ 291,709	$ 216,495	58 %	35 %
Impairment of oil and natural gas properties	2,377,615	149,000	54,373	n/a	n/a
Impairment of goodwill	95,947	—	—	n/a	n/a
G&A excluding unit based compensation (g)	$ 73,537	$ 63,562	$ 38,752	16 %	64 %
G&A excluding unit based compensation per Boe	$ 3.64	$ 4.50	$ 3.53	(19)%	27 %

(a) Natural gas is converted on the basis of six Mcf of gas per one Bbl of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a Bbl of oil equivalent for natural gas is significantly less than the price for a Bbl of oil.

(b) Excludes the effect of commodity derivative settlements.

(c) Includes the per Boe price effect of oil purchases.

(d) Oil sales were 11,287 MBoe, 7,773 MBoe, and 5,655 MBoe for 2015, 2014 and 2013 respectively.

(e) Includes ad valorem and severance taxes.

(f) Includes lease operating expenses, district expenses, transportation expenses and processing fees.

(g) Includes acquisition and integration costs of $12.6 million, $14.5 million, and $5.0 million for 2015, 2014, and 2013, respectively.

Comparison of Results of Operations for the Years Ended December 31, 2015, 2014 and 2013

The variances in our results of operations were due to the following components:

Production

For the year ended December 31, 2015, compared to the year ended December 31, 2014, production volumes increased by 6,066 MBoe, or 43%, primarily due to 6,730 MBoe of production from the properties acquired in the QRE Merger in November 2014 (the "QRE Properties") partially offset by lower production of 203 MBoe in the Rockies, 194 MBoe in legacy Permian, 133 MBoe in our Midwest properties and 107 MBoe in our California properties. In 2015, oil, NGLs and natural gas accounted for 56%, 9% and 35% of our production, respectively.

For the year ended December 31, 2014, compared to the year ended December 31, 2013, production volumes increased by 3,131 MBoe, or 29%, primarily due to a 1,204 MBoe higher production from our Mid-Continent properties acquired in July 2013, 1,200 MBoe higher production from our Permian Basin properties acquired in December 2013, 897 MBoe of production from the QRE Properties (including 418 MBoe in Ark-La-Tex, 265 MBoe in the Permian Basin, 161 MBoe in Southeast and 53 in Mid-Continent) and 182 MBoe higher California production, primarily from our Santa Fe Springs field, partially offset by 206 MBoe and 80 MBoe lower production in the Midwest and the Rockies, respectively, primarily due to severe winter weather and natural field declines and 68 MBoe lower production in Florida primarily due to well performance and natural field declines. In 2014, oil, NGLs and natural gas accounted for 56%, 8% and 36% of our production, respectively.

Oil, NGL and natural gas sales

Total oil, NGL and natural gas sales revenues decreased $210.5 million for the year ended December 31, 2015, compared to the year ended December 31, 2014. Crude oil revenues decreased $165.3 million due to lower average crude oil prices, partially offset by production from the QRE Properties. Realized prices for oil, excluding the effect of derivative instruments, decreased $41.62 per Bbl, or 48%, for the year ended December 31, 2015 compared to the year ended December 31, 2014. NGL revenues decreased $11.7 million due to lower average NGL prices, partially offset by production from the QRE Properties. Realized prices for NGLs decreased $20.44 per Bbl, or 58%, for the year ended December 31, 2015 compared to the year ended December 31, 2014. Natural gas revenues decreased $33.5 million, primarily due to lower average natural gas prices, partially offset by production from the QRE Properties. Realized prices for natural gas, excluding the effect of derivative instruments, decreased $2.15 per Mcf, or approximately 45%, for the year ended December 31, 2015 compared to the year ended December 31, 2014.

Total oil, NGL and natural gas sales revenues increased $195.2 million for the year ended December 31, 2014, compared to the year ended December 31, 2013. Crude oil revenues increased $138.7 million due to higher oil sales volume primarily due to production from our 2013 and 2014 acquisitions. Realized prices for oil, excluding the effect of derivative instruments, decreased $7.59 per Bbl, or 8%, for the year ended December 31, 2014 compared to the year ended December 31, 2013. NGL revenues increased $18.5 million due to higher NGL sales volumes primarily due to production from our 2013 and 2014 acquisitions, and slightly higher NGL prices. Realized prices for NGLs increased $0.21 per Bbl, or 1%, for the year ended December 31, 2014 compared to the year ended December 31, 2013. Natural gas revenues increased $38.0 million, primarily due to higher natural gas prices, particularly in Michigan due to severe winter weather, and higher natural gas production primarily due to production from our 2013 and 2014 acquisitions. Realized prices for natural gas, excluding the effect of derivative instruments, increased $1.00 per Mcf, or approximately 26%, for the year ended December 31, 2014 compared to the year ended December 31, 2013.

Gain (loss) on commodity derivative instruments

Gain on commodity derivative instruments for the year ended December 31, 2015 was $438.6 million compared to a gain of $566.5 million for the year ended December 31, 2014. Net settlements received on oil derivative instruments for the year ended December 31, 2015 were $431.1 million compared to net settlements received of $18.2 million for the year ended December 31, 2014, primarily due to significantly lower commodity prices compared to our average oil hedge prices in 2015. Net settlements received on natural gas derivative instruments for the year ended December 31, 2015 were $68.9 million compared to $9.6 million for the year ended December 31, 2014, primarily due to lower commodity prices compared to our average natural gas hedge prices in 2015.

Mark-to-market loss on oil derivative instruments for the year ended December 31, 2015 was $45.2 million compared to mark-to-market gain of $508.1 million for the year ended December 31, 2014, primarily due to a significant decrease in oil future prices during 2015. Mark-to-market loss on natural gas commodity derivative instruments for the year ended December 31, 2015 was $16.2 million compared to a gain of $30.6 million for the year ended December 31, 2014, primarily due to lower natural gas future prices during 2015 compared to natural gas futures prices in 2014.

Gain on commodity derivative instruments for the year ended December 31, 2014 was $566.5 million compared to a loss of $29.2 million for the year ended December 31, 2013. Net settlements received on oil derivative instruments for the year ended December 31, 2014 were $18.2 million compared to net settlements paid of $36.2 million for the year ended December 31, 2013, primarily due to lower average oil prices in 2014. Net settlements received on natural gas derivative instruments for the year ended December 31, 2014 were $9.6 million compared to $44.3 million for the year ended December 31, 2013, primarily due to higher average natural gas prices in 2014.

Mark-to-market gain on oil derivative instruments for the year ended December 31, 2014 was $508.1 million compared to mark-to-market gain of $6.6 million for the year ended December 31, 2013, primarily due to a significant decrease in oil future prices during 2014. Mark-to-market gain on natural gas commodity derivative instruments for the year ended December 31, 2014 was $30.6 million compared to a loss of $43.9 million for the year ended December 31, 2013, primarily due to a decrease in natural gas future prices during 2014 compared to an increase in natural gas futures prices in 2013.

Other Revenues

Other revenues increased $17.2 million for the year ended December 31, 2015 compared to the year ended December 31, 2014, primarily due to $14.3 million higher salt water disposal revenue, $1.9 million higher sulfur sales revenue and $1.1 million CO_2 gas revenue.

Other revenues increased $4.4 million for the year ended December 31, 2014 compared to the year ended December 31, 2013, primarily due to $3.5 million higher pipeline related revenues from our 2013 acquisitions and $1.8 million of salt water disposal revenue.

Lease operating expenses

Pre-tax lease operating expenses, including district expenses, transportation expenses and processing fees, for the year ended December 31, 2015 totaled $383.8 million, $92.4 million higher than 2014. The increase in pre-tax lease operating expenses reflects the full year effect of lease operating costs for the QRE Properties. On a per Boe basis, pre-tax lease operating expenses were 8% lower than the year ended December 31, 2014 at $19.02 per Boe, primarily due to lower commodity prices.

Production and property taxes for the year ended December 31, 2015 totaled $51.2 million, which was $10.9 million lower than the year ended December 31, 2014, primarily due to lower crude oil and natural gas prices, partially offset by higher production. On a per Boe basis, production and property taxes for the year ended December 31, 2015 were $2.54 per Boe, which was 42% lower than the year ended December 31, 2014.

Pre-tax lease operating expenses, including district expenses, transportation expenses and processing fees, for the year ended December 31, 2014 totaled $293.6 million, $77.3 million higher than 2013. The increase in pre-tax lease operating expenses reflects our 2013 and 2014 acquisitions. On a per Boe basis, pre-tax lease operating expenses were 6% higher than the year ended December 31, 2013 at $20.65 per Boe, primarily due to higher workover expenses, labor costs and fuel and utility costs in the Permian Basin and Mid-Continent.

Production and property taxes for the year ended December 31, 2014 totaled $62.1 million, which was $15.9 million higher than the year ended December 31, 2013, primarily due to additional production from our 2013 and 2014 acquisitions and higher natural gas prices. On a per Boe basis, production and property taxes for the year ended December 31, 2014 were $4.40 per Boe, which was 5% higher than the year ended December 31, 2013, primarily due to higher oil production as a percentage of total production and higher natural gas prices partially offset by lower crude oil prices.

Change in inventory

In Florida, our oil sales are a function of the number and size of oil shipments in each year and thus oil sales do not always coincide with volumes produced in a given year. Sales occur on average every six to eight weeks. We match production expenses with oil sales. Production expenses associated with unsold oil inventory are credited to operating costs through the change in inventory account. Production expenses are charged to operating costs through the change in inventory account when they are sold. In 2015, the change in inventory account amounted to a charge of $2.4 million primarily due to a higher volume of barrels sold than produced during the year and a $0.6 million write-off of crude oil inventory due to a decrease in oil prices in the fourth quarter of 2015. In 2014, the change in inventory account amounted to a credit of $0.7 million primarily due to a lower volume of barrels sold than produced during the year and a $0.6 million credit for physical inventory adjustments, partially offset by a $1.0 million write-off of crude oil inventory due to a decrease in oil prices in the fourth quarter of 2014. In 2013, the change in inventory account amounted to a credit of $1.0 million reflecting higher production costs for the unsold inventory.

Depletion, depreciation and amortization

Depletion, depreciation and amortization ("DD&A") expense totaled $460.0 million for the year ended December 31, 2015, compared to $291.7 million for the year ended December 31, 2014. The 58% increase in DD&A was primarily due to lower oil and natural gas prices, and the effect those prices had on our reserve volumes and DD&A rates, as well as the addition of QRE Properties acquired at higher values and capital expenditures incurred during the year ended December 31, 2015. For the years ended December 31, 2015 and December 31, 2014, DD&A included $2.2 million and $3.9 million, respectively, of amortization of intangible assets related to CO_2 contracts acquired in the 2013 Mid-Continent acquisitions. For the year ended December 31, 2015, DD&A per Boe was 10% higher than prior year at $22.80 per Boe compared to $20.67 per Boe for the year ended December 31, 2014, primarily due to lower commodity prices and their impact on our reserve volumes and DD&A rates.

DD&A expense totaled $291.7 million for the year ended December 31, 2014, compared to $216.5 million for the year ended December 31, 2013. The 35% increase in DD&A was primarily due to higher production from our 2013 and 2014 acquisitions. For the years ended December 31, 2014 and 2013, DD&A included $3.9 million and $3.6 million, respectively, of amortization of intangible assets related to CO_2 contracts acquired in the 2013 Mid-Continent acquisitions. For the year ended December 31, 2014, DD&A per Boe was 5% higher than prior year at $20.67 per Boe compared to $19.71 per Boe for the year ended December 31, 2013, primarily due to higher oil production as a percentage of total production and higher California DD&A rates, partially offset by lower DD&A rates from our Midwest properties driven by higher reserves related to an increase in natural gas prices.

Impairments

During the year ended December 31, 2015, we recorded impairments of $2.4 billion, including $740.6 million in the Midwest, $512.8 million in Ark-La-Tex, $443.8 million in the Southeast, $256.5 million in the Permian Basin, $213.0 million in California, $147.9 million in the Rockies and $63.0 million in Mid-Continent. The impairments were primarily due to the impact that the prolonged drop in commodity prices had on our projected future net revenues.

During the year ended December 31, 2014, we recorded impairments of $149.0 million, including $124.8 million in the Southeast, $11.2 million in the Rockies and $8.5 million in the Midwest, $2.3 million in the Permian Basin, $2.2 million in Mid-Continent. The impairments in the Southeast were due to reserve adjustments primarily related to lower crude oil prices and well performance. The Rockies impairments were due to reserve adjustments related to a combination of lower commodity prices, well performance and higher expense projections. The Midwest impairments related to lower commodity prices and the write-off of investments associated with expiring leases that we elected not to renew. The Permian Basin and Mid-Continent property impairments related to lower commodity prices.

For the year ended December 31, 2013, we recorded an asset impairment charge of $54.4 million, including $28.3 million of impairments to our Michigan non-Antrim oil and gas properties due to negative reserve adjustments due to lower performance and a decrease in expected future commodity prices, and $25.3 million of impairments to an oil property in our Bighorn Basin in Northern Wyoming due to a negative reserve adjustment due to lower performance and a decrease in expected future oil prices.

Goodwill Impairment

During 2015, we had $95.9 million of goodwill related to the 2014 QRE Merger (see Note 3). Due to a decrease in the price of our Common Units during the second quarter of 2015, we performed a qualitative goodwill impairment assessment. In the first step of the goodwill impairment test, we determined that the fair value of our goodwill was less than the carrying amount, primarily due to the decrease in the price of our Common Units. Therefore, we performed the second step of the goodwill impairment test, which led us to conclude that there was no remaining implied fair value attributable to goodwill. Based on this assessment, we recorded a non-cash goodwill impairment charge of $95.9 million during the second quarter of 2015.

General and administrative expenses

Our G&A expenses totaled $99.0 million and $86.9 million in 2015 and 2014, respectively. This included $25.5 million and $23.4 million, respectively, in non-cash unit-based compensation expense related to employee incentive plans. For 2015, G&A expenses, excluding non-cash unit-based compensation, were $73.5 million, which was $10.0 million higher than 2014. The increase was primarily due to higher payroll expense for additional personnel attributable to our 2014 acquisitions. On a per Boe basis, G&A expenses, excluding non-cash unit-based compensation, were $3.64 in 2015, which was a 19% decrease from 2014. Excluding acquisition and integration related costs, G&A expenses per Boe were $3.02 and $3.48 for the year ended December 31, 2015 and 2014, respectively.

Our G&A expenses totaled $86.9 million and $58.7 million in 2014 and 2013, respectively. This included $23.4 million and $20.0 million, respectively, in non-cash unit-based compensation expense related to employee incentive plans. For 2014, G&A expenses, excluding non-cash unit-based compensation, were $63.5 million, which was $24.7 million higher than 2013. The increase was primarily due to $14.5 million of acquisition and integration related costs, including $13.6 million for the QRE Merger, higher payroll expense for additional personnel attributable to our 2013 and 2014 acquisitions and higher information technology ("IT") costs. On a per Boe basis, G&A expenses, excluding non-cash unit-based compensation, were $4.50 in 2014, which was a 28% increase from 2013, primarily due to one-time acquisition and IT costs incurred during 2014. Excluding acquisition related costs, G&A expenses per Boe were $3.48 and $3.08 for the year ended December 31, 2014 and 2013, respectively.

Restructuring costs

In the first quarter of 2015, we completed a workforce reduction plan as part of a company-wide reorganization effort intended to reduce costs, due in part to lower commodity prices. The reduction was communicated to affected employees on various dates during March, and all such notifications were completed by March 31, 2015. The plan resulted in a reduction of approximately 37 employees, primarily in administrative and support positions. In April 2015, we communicated further reductions to an additional 8 employees. For the year ended December 31, 2015, we recognized a total cost of $6.4 million, which included severance cash payments of $4.8 million, unit-based compensation of $1.3 million and other termination costs of $0.3 million. Total workforce reductions in 2015 as a result of the workforce reduction plan, voluntary resignations and early retirement exceeded 60 positions.

Interest expense, net of amounts capitalized

Interest expense totaled $203.0 million and $127.0 million for the years ended December 31, 2015 and 2014, respectively. The increase of $76.1 million in interest expense was primarily attributable to $43.8 million of interest on our Senior Secured Notes issued in April 2015, approximately $17.5 million higher credit facility interest expense as a result of higher borrowings and $10.6 million write-off of debt issuance costs associated with the reduction of our credit facility borrowing base in April 2015. Interest expense, excluding debt amortization, totaled $178.1 million and $119.1 million for the years ended December 31, 2015 and 2014, respectively.

Interest expense totaled $127.0 million and $87.1 million for the years ended December 31, 2014 and 2013, respectively. The increase of $39.9 million in interest expense was primarily attributable to $30.6 million higher interest on our 7.875% senior notes due 2022 issued in November 2013, approximately $8.1 million higher credit facility interest expense as a result of higher borrowings and slightly higher interest rates and approximately $1.4 million higher amortization of debt issuance costs. Interest expense, excluding debt amortization, totaled $119.1 million and $80.6 million for the years ended December 31, 2014 and 2013, respectively.

Loss on interest rate swaps

We are subject to interest rate risk associated with loans under our credit facility that bear interest based on floating rates. In order to mitigate our interest rate exposure, as of December 31, 2015, we had interest rate swaps, indexed to 1-month LIBOR, to fix a portion of floating LIBOR-base debt under our credit facility for 2016 and 2017, for notional amounts of $710 million and $200 million, respectively, with average fixed rates of 1.28% and 1.23%, respectively. As of December 31, 2014, we had interest rate swaps, indexed to 1-month LIBOR, to fix a portion of floating LIBOR-base debt under our credit facility for 2015 and 2016, for notional amounts of $407 million and $410 million, respectively, with average fixed rates of 1.59% and 1.72%, respectively. See Part II—Item 7A "—Quantitative and Qualitative Disclosures About Market Risk" in this report for a discussion of our interest rate risk. Gain/loss on interest swaps for the years ended December 31, 2015, 2014 and 2013 were a loss of $2.7 million, gain of $0.5 million, and none, respectively.

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated from operating activities, amounts available under our credit facility and cash from the issuance of secured and unsecured long-term debt and partnership units. Historically, our primary uses of cash have been for our operating expenses, capital expenditures, acquisitions and cash distributions to unitholders. To fund certain acquisition transactions, we have also sourced the private placement markets and have issued equity as partial consideration for the acquisition of oil and natural gas properties. As market conditions have permitted, we have also engaged in non-core asset sale transactions. Future cash flow is subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and have continued to decline in 2015 through the first quarter of 2016. These lower commodity prices have negatively impacted revenues, earnings and cash flows, and sustained low oil and natural gas prices will have a material adverse effect on our liquidity position.

On April 8, 2015, we completed private offerings of $650 million of Senior Secured Notes and $350 million of Series B Preferred Units. We received net proceeds of approximately $944 million from these offerings, which we used primarily to repay borrowings under our credit facility. Concurrently with those transactions, we also amended our credit facility to establish a borrowing base of $1.8 billion until April 1, 2016, subject, starting with the October 1, 2015 borrowing base redetermination date, to our having liquidity (inclusive of borrowing base availability) of 10% of the borrowing base.

As of February 25, 2016, we had approximately $1.2 billion in borrowings under our credit facility. Our credit facility limits the amounts we can borrow to a borrowing base amount determined by the lenders at their sole discretion based on their valuation of our proved reserves and their other internal criteria. The borrowing base at December 31, 2015 was $1.8 billion and the next semi-annual redetermination is scheduled for April 2016. Based upon current commodity prices and other factors at the time of future redeterminations, we expect our borrowing base to be significantly decreased. Without a waiver from our lenders, our credit facility currently provides that if the borrowing base is reduced below our current outstanding borrowings, we are required to repay the deficiency in five equal monthly installments. Although our lenders have the discretion to redetermine the borrowing base below our current outstanding borrowings, we do not expect that to occur in April 2016. However, if commodity prices remain depressed or further decline, we expect our borrowing base to be reduced again at the subsequent borrowing base redetermination in October 2016, which could further impact and limit our liquidity.

We believe our existing cash resources and hedge positions should provide us with sufficient funds to meet our expected working capital needs for 2016, assuming that our borrowing base is redetermined above our current outstanding borrowings. Although we currently expect our sources of capital to be sufficient to meet our near-term liquidity needs, there can be no assurance that the lenders under our credit facility will not reduce the borrowing base to an amount below our current outstanding borrowings in April or at the October 2016 redetermination or that our liquidity requirements will continue to be satisfied, given current oil prices and the discretion of our lenders to decrease our borrowing base. Due to the steep decline in commodity prices, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable. The cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, and reduced and, in many cases, ceased to provide any new funding. We expect that we will take other actions to raise funds to repay debt, such as selling non-core assets or restructuring derivative contracts.

As a result of both the low commodity price environment and our substantial debt burden, our liquidity will remain limited absent a material improvement in oil and natural gas prices or a refinancing or restructuring of our balance sheet debt. We may engage financial and legal advisors to advise our management and our Board of Directors regarding potential strategic alternatives such as a refinancing or restructuring of our indebtedness or capital structure or seeking to raise additional capital through debt or equity financing to address our leverage and liquidity issues. We are also focused on cost reductions and the identification of non-core assets for potential sale. We cannot give any assurances that any of these efforts will be possible on acceptable terms or will be successful or result in actual cost reductions or additional cash flows or the timing of any such potential results.

Equity Offerings

On April 8, 2015, we issued $350 million of Series B Preferred Units in a private offering to EIG Equity and certain other purchasers at an issue price of $7.50 per unit and received approximately $337.2 million from these offerings, net of fees and estimated expenses.

During the year ended December 31, 2015, we issued approximately 0.5 million Common Units under the Equity Distribution Agreement for net proceeds of $3.1 million.

In November 2014, we issued 71.5 million Common Units to QRE as partial consideration for the QRE Merger. The fair value of the units on the date of the merger was $14.73 per Common Unit, or $1.06 billion.

In October 2014, we sold 14.0 million Common Units at a price to the public of $18.64 per Common Unit, resulting in proceeds, net of underwriting discounts and expenses, of $251.6 million. In May 2014, we sold 8.0 million 8.25% Series A Preferred Units at a price to the public of $25.00 per Series A Preferred Unit, resulting in proceeds, net of underwriting discounts and expenses, of $193.2 million.

During the year ended December 31, 2014, we issued approximately 1.3 million Common Units under the Equity Distribution Agreement for net proceeds of $26.2 million.

We primarily used the proceeds from these offerings to reduce borrowings under our credit facility.

Senior Notes

On April 8, 2015, we issued $650 million Senior Secured Notes in a private offering to EIG Redwood Debt Aggregator, LP and certain other purchasers at a purchase price of 97% of the principal amount. We received approximately $606.9 million from this offering, net of fees and estimated expenses, which we primarily used to repay borrowings under our credit facility. Interest on our Senior Secured Notes is payable quarterly in March, June, September and December. As of December 31, 2015, our Senior Secured Notes had a carrying value of $632.7 million, net of unamortized discount of $17.3 million.

We have outstanding $850 million in aggregate principal amount of 7.875% Senior Notes due 2022 (the “2022 Senior Notes”) and $305 million in aggregate principal amount of 8.625% Senior Notes due 2020 (the “2020 Senior Notes” and together with the 2022 Senior Notes, the “Senior Unsecured Notes.” Interest on the Senior Unsecured Notes is payable twice a year in April and October. As of December 31, 2015, we were in compliance with the covenants of our Senior Unsecured Notes.

Credit Facility

BOLP, as borrower, and we and our wholly-owned subsidiaries, as guarantors, have a $5.0 billion revolving credit facility with Wells Fargo Bank National Association, as Administrative Agent, Swing Line Lender and Issuing Lender, and a syndicate of banks with a maturity date of November 19, 2019. On April 8, 2015, in connection with the Series B Preferred Units and Senior Secured Notes offerings, we entered into the First Amendment (the “First Amendment”) to the Third Amended and Restated Credit Agreement (as amended, the “Credit Amendment”). Among other changes, the First Amendment: (i) established a borrowing base of $1.8 billion until the April 1, 2016 scheduled redetermination date subject, starting with the October 1, 2015 scheduled redetermination date, to our having liquidity (inclusive of borrowing base availability) of 10% of the borrowing base; (ii) permitted $650 million of second lien indebtedness; (iii) increased the base rate and LIBOR margins by 0.25%; (iv) added a requirement that we have liquidity (inclusive of borrowing base availability) of 10% of the borrowing base after giving effect to any distribution on our common units or voluntary prepayment of second lien indebtedness; and (v) added a requirement that we have liquidity (inclusive of borrowing base availability) of 5% of the borrowing base after giving effect to any distribution on our Series B Preferred Units.

Our credit facility limits the amounts we can borrow to a borrowing base amount determined by the lenders at their sole discretion based on their valuation of our proved reserves and their internal criteria. The borrowing base at December 31, 2015 was $1.8 billion and the next semi-annual redetermination is scheduled for April 2016.

Our borrowing base is automatically reduced by an amount equal to 25% of the principal of newly issued senior unsecured notes and second lien indebtedness, except if the proceeds of such indebtedness are used to refinance certain existing indebtedness. Loans under the Credit Agreement will bear interest by reference to a Base Rate, LIBOR or a LIBOR Market Index Rate (each as defined in the Credit Agreement), plus an applicable margin that is determined pursuant to a pricing grid which varies between 75 and 175 basis points (in the case of Base Rate loans) and between 175 and 275 basis points (in the case of LIBOR and LIBOR Market Index Rate loans) based on a ratio of loans and letters of credit outstanding to the borrowing base.

As of December 31, 2015, the lending group under the Credit Agreement included 35 banks. Of the $1.8 billion in total commitments under the credit facility, Wells Fargo Bank National Association held approximately 5% of the commitments, with the remaining 34 banks holding between 1% and 4.2% of the commitments. In addition to our relationships with these institutions under the credit facility, from time to time we engage in other transactions with a number of these institutions. Such institutions or their affiliates may serve as underwriter or initial purchaser of our debt and equity securities and/or serve as counterparties to our commodity and interest rate derivative agreements.

We had outstanding borrowings under our credit facility of $1.23 billion as of December 31, 2015 and $1.20 billion as of February 25, 2016.

Our credit facility contains customary covenants, including restrictions on our ability to: incur additional indebtedness; make certain investments, loans or advances; permit the interest coverage ratio (defined as the ratio of EBITDAX to Consolidated Interest Expense) to be less than 2.50 to 1.00; make distributions to our unitholders or repurchase units; make dispositions or enter into sales and leasebacks; or enter into a merger or sale of our property or assets, including the sale or transfer of interests in our subsidiaries. EBITDAX is not a defined US GAAP measure. The Credit Agreement defines EBITDAX as consolidated net income plus exploration expense, interest expense, income tax provision, DD&A, unrealized loss or gain on derivative instruments, non-cash charges, including non-cash unit-based compensation expense, loss or gain on sale of assets (excluding gain or loss on monetization of derivative instruments for the following twelve months), cumulative effect of changes in accounting principles, cash distributions received from our unrestricted entities (as defined in the Credit Agreement) and excluding income from our unrestricted entities. If any acquisition or disposition was consummated during an applicable quarter, all calculations of EBITDAX shall be determined on a pro forma basis.

In addition, our credit facility includes a restriction on our ability to make a distribution unless, after giving effect to such distribution, we remain in compliance with all terms and conditions of our credit facility. The events that constitute an event of default under the Credit Agreement include: payment defaults; misrepresentations; breaches of covenants; cross-default and cross-acceleration to certain other indebtedness; adverse judgments against us in excess of a specified amount; changes in management or control; loss of permits; certain insolvency events; and assertion of certain environmental claims. As of December 31, 2015, we were in compliance with our credit facility's covenants.

Please see Part I—Item 1A "—Risk Factors"— "Risks Related to Our Business — Our credit facility has substantial conditions, restrictions and financial covenants that may restrict our business and financing activities and our ability to reinstate distributions" in this report for more information on the effect of an event of default under the Credit Agreement.

Cash Flows

Operating activities. Our cash flow from operating activities in 2015 was $436.7 million compared to $357.8 million in 2014. The increase in cash flows from operating activities was primarily due to higher sales revenues in 2015 driven by a 45% increase in sales volume from the QRE Properties, which increased sales revenue by approximately $383.9 million and $472.2 million in higher commodity derivative settlement receipts primarily due to lower commodity prices. These positive factors were partially offset by lower physical sales revenue driven by lower commodity prices, which decreased sales revenue by approximately $596.5 million, $99.5 million of additional operating costs primarily from the full year effect related to the QRE Properties, and $64.6 million higher cash interest expense paid due to higher debt levels.

Our cash flow from operating activities in 2014 was $357.8 million compared to $257.2 million in 2013. The increase in cash flows from operating activities was primarily due to higher revenues driven by our 2013 and 2014 acquisitions, higher natural gas prices and higher net settlement receipts on oil derivative instruments, partially offset by lower crude oil prices, higher operating costs and higher interest expense.

Investing activities. Net cash used in investing activities for the year ended December 31, 2015 was $274.0 million, which was predominantly spent on capital expenditures. In 2015, we spent $269.4 million on capital expenditures, consisting of $255.8 million primarily for drilling and completion activities, and approximately $13.6 million for IT and other capital expenditures, $18.2 million on property acquisitions, primarily for CO_2 producing properties, $4.0 million on purchases of available-for-sale securities and $0.9 million in advances made for the purchase of future CO_2 supply for our Oklahoma properties, partially offset by $14.5 million in proceeds from sale of assets and $3.9 million in proceeds from the sale of available-for-sale securities.

Net cash used in investing activities for the year ended December 31, 2014 was $837.0 million, which was predominantly spent on property acquisitions. Property acquisitions of $401.5 million in 2014 primarily included $344.9 million for the QRE Merger and $50.0 million for the 2014 Antares Acquisition. In 2014, we also spent $417.8 million for capital expenditures, primarily for drilling and completions, and $11.7 million in advances made for the purchase of future CO_2 supply for our Mid-Continent properties.

Net cash used in investing activities for the year ended December 31, 2013 was $1.47 billion which was predominately spent on property acquisitions. Property acquisitions of $1.18 billion in 2013 included $875.5 million for the 2013 Mid-Continent acquisitions and $302.1 million for the 2013 Permian Basin acquisitions. In 2013, we also spent $266.3 million for capital expenditures, primarily for drilling and completions, $11.7 million in advances made for the purchase of future CO_2 supply for our Mid-Continent properties and $15.0 million deposit related to negotiations undertaken to secure additional future CO_2 supply.

Financing activities. Net cash used in financing activities for the year ended December 31, 2015 was $164.9 million compared to provided by financing activities of $489.4 million for the year ended December 31, 2014. We had net repayments from the issuance of long-term debt under our credit facility of $966 million in 2015 compared to net proceeds of $672.6 million in 2014. We had net proceeds of $606.9 million in connection with the issuance of the Senior Secured Notes. In addition, for the year ended December 31, 2015, we received net cash proceeds from the issuance of Common Units of $3.0 million, received net cash proceeds of $337.2 million from the issuance of the Series B Preferred Units, made cash distributions of $142.7 million and paid $29.3 million in debt issuance costs.

Net cash provided by financing activities for the year ended December 31, 2014 was $489.4 million compared to $1,206.6 million for the year ended December 31, 2013. We had net proceeds from the issuance of long-term debt under our credit facility of $672.6 million in 2014 compared to $789.0 million in 2013. The increase in our debt in 2014 and 2013 was primarily due to borrowings for property acquisitions. In addition, for the year ended December 31, 2014, we received net cash proceeds from the issuance of Common Units of $277.6 million, received net cash proceeds of $193.2 million from the issuance of Series A Preferred Units, paid $352.5 million to redeem the senior notes assumed in the QRE Merger, made cash distributions of $273.9 million and paid $25.1 million in debt issuance costs. For the year ended December 31, 2013, we received net cash proceeds from the issuance of Common Units of $618.0 million, made cash distributions of $186.9 million and paid $15.6 million in debt issuance costs.

Off-Balance Sheet Arrangements

We did not have any off-balance sheet arrangements as of December 31, 2015.

Contractual Obligations and Commitments

The following table summarizes our financial contractual obligations as of December 31, 2015. Some of these contractual obligations are reflected in the balance sheet, while others are disclosed as future obligations under US GAAP.

	Payments Due by Year						
Thousands of dollars	2016	2017	2018	2019	2020	Thereafter	Total
Credit facility (a)	$ 154,000	$ —	$ —	$ 1,075,000	$ —	$ —	$ 1,229,000
Credit facility commitment fees	2,726	2,726	2,726	2,412	—	—	10,590
Senior Notes (b)	—	—	—	—	955,000	850,000	1,805,000
Estimated interest payments (c)	186,306	186,306	186,306	182,516	110,812	86,461	938,707
Operating lease obligations	11,368	11,323	7,037	5,615	5,648	14,480	55,471
Asset retirement obligations (d)	2,341	5,116	8,242	528	3,797	234,354	254,378
Deferred premiums	2,742	2,612	—	—	—	—	5,354
Total	$ 359,483	$ 208,083	$ 204,311	$ 1,266,071	$ 1,075,257	$ 1,185,295	$ 4,298,500

(a) $154 million classified as a current liability represents the estimated amount of our total credit facility debt at December 31, 2015 that is in excess of our projected borrowing base. Our credit facility matures on November 19, 2019.

(b) Represents 9.25% Senior Secured Notes due 2020 with a face value of $650 million, 8.625% senior notes due 2020 with a face value of $305 million and 7.875% Senior Notes due 2022 with a face value of $850 million.

(c) Based on total debt balance and interest rates in effect at December 31, 2015.

(d) Amounts represent our estimate of future asset retirement obligations on an discounted basis. See Note 12 to the consolidated financial statements in this report.

Surety Bonds and Letters of Credit

In the normal course of business, we have performance obligations that are secured, in whole or in part, by surety bonds or letters of credit. These obligations primarily relate to abandonments, environmental and other responsibilities where governmental and other organizations require such support. These surety bonds and letters of credit are issued by financial institutions and are required to be reimbursed by us if drawn upon. At December 31, 2015, we had $27.1 million in surety bonds and $25.8 million in letters of credit outstanding. At December 31, 2014, we had $21.1 million in surety bonds and $26.5 million in letters of credit outstanding.

Credit and Counterparty Risk

Financial instruments that potentially subject us to concentrations of credit risk consist principally of derivatives and accounts receivable. Our derivatives are exposed to credit risk from counterparties. As of December 31, 2015 and February 25, 2016, our derivative counterparties were Bank of Montreal, Barclays Bank PLC, BNP Paribas, Canadian Imperial Bank of Commerce, Citibank, N.A., Citizens Bank, National Association, Comerica Bank, Credit Agricole Corporate and Investment Bank, Credit Suisse Energy LLC, Credit Suisse International, ING Capital Markets LLC, JP Morgan Chase Bank N.A., Merrill Lynch Commodities, Inc., Morgan Stanley Capital Group Inc., Royal Bank of Canada, The Bank of Nova Scotia, The Toronto-Dominion Bank, Union Bank N.A. and Wells Fargo Bank, N.A. Our counterparties are all lenders under our Credit Agreement. During 2008 and 2009, there was extreme volatility and disruption in the capital and credit markets. While the market has become more stable, future volatility could adversely affect the financial condition of our derivative counterparties. On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits and monitor the appropriateness of these limits on an ongoing basis. We periodically obtain credit default swap information on our counterparties. As of February 25, 2016 and December 31, 2015, each of these financial institutions had an investment grade credit rating. Although we currently do not believe we have a specific counterparty risk with any party, our loss could be substantial if any of these parties were to default. As of December 31, 2015, our largest derivative asset balances were with Wells Fargo Bank, N.A., Barclays Bank PLC, Credit Suisse Energy LLC and Morgan Stanley Capital Group Inc., which accounted for approximately 15%, 13%, 11% and 11% of our derivative asset balances, respectively. See Note 4 to the consolidated financial statements in this report for more information regarding our derivatives.

Accounts receivable are primarily from purchasers of oil and natural gas products. We have a portfolio of oil, NGL and natural gas sales contracts with large, established refiners and utilities. Our sales contracts are sold at market-sensitive or spot prices. Because our products are commodity products sold primarily on the basis of price and availability, we are not dependent upon one purchaser or a small group of purchasers. For the years ended December 31, 2015, 2014 and 2013, we sold oil, NGL and natural gas production representing 10% or more of total revenue to the following purchasers:

	Year Ended December 31,		
	2015	2014	2013
Shell Trading	24%	22%	15%
Plains Marketing	12%	(a)	(a)
Phillips 66	(a)	10%	15%
Marathon Oil Corporation	(a)	(a)	10%

(a) Represented less than 10% of total sales revenue for the respective year end.

As of December 31, 2015, Shell Trading and Plains Marketing, the only customers who accounted for 10% or more of our trade accounts receivables, comprised 13% and 11%, respectively, of our outstanding trade receivables.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements, which have been prepared in accordance with US GAAP. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments. The development, selection and disclosure of each of these policies is reviewed by our audit committee. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of our financial statements. See Note 2 to the consolidated financial statements in this report for a discussion of additional accounting policies and estimates made by management.

Successful Efforts Method of Accounting

We account for oil and gas properties using the successful efforts method. Under this method of accounting, leasehold acquisition costs are capitalized. Subsequently, if proved reserves are found on unproved property, the leasehold costs are transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

DD&A of producing oil and gas properties is recorded based on units of production. 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, both developed and undeveloped, and capitalized development costs (wells and related equipment and facilities) are amortized on the basis of proved developed reserves.

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

Oil and gas properties are reviewed for impairment periodically and when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of oil and 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. For purposes of performing an impairment test, the undiscounted cash flows are forecast using five-year NYMEX forward strip prices at the end of the period and escalated thereafter at 2%. Production and development cost estimates (e.g. operating expenses and development capital) are conformed to reflect the commodity price strip used where applicable. For impairment charges, the associated property's expected future net cash flows were discounted using a long-term weighted average cost of capital which approximated 10% at December 31, 2015. Reserves are calculated based upon reports from third party engineers adjusted for acquisitions or other changes occurring during the year as determined to be appropriate in the good faith judgment of management. Unproved 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.

We capitalize interest costs to oil and gas properties on expenditures made in connection with certain projects such as drilling and completion of new oil and natural gas wells and major facility installations. Interest is capitalized only for the period that such activities are in progress. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using the units of production method.

The Partnership carries out tertiary recovery methods on certain of its oil and gas properties in Oklahoma in order to recover additional hydrocarbons that are not recoverable from primary or secondary recovery methods. Acquisition costs of tertiary injectants, such as nitrogen and purchased CO_2, for enhanced oil recovery activities that are used prior to the recognition of proved tertiary recovery reserves are expensed as incurred. After a project has been determined to be technically feasible and economically viable, all acquisition costs of tertiary injectants are capitalized as development costs and depleted, as they are incurred solely for obtaining access to reserves not otherwise recoverable and have future economic benefits over the life of the project. As CO_2 is recovered together with oil and gas production, it is extracted and re-injected, and all the associated CO_2 recycling costs are expensed as incurred. Likewise, costs incurred to maintain reservoir pressure are also expensed.

Business Combinations

We account for all business combinations using the acquisition method. Under the acquisition method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given, whether in the form of cash, assets, equity or the assumption of liabilities. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if material, is recognized as a gain at the time of acquisition. All purchase price allocations are finalized within one year from the acquisition date.

Oil and Gas Reserve Quantities

The estimates of our proved reserves are based on the quantities of oil, NGLs and 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. Annually, CGA and NSAI prepare reserve and economic evaluations of all our properties on a well-by-well basis.

Estimated proved 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 prepare our disclosures for reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The independent engineering firms described above adhere to the same guidelines when preparing their reserve reports. The accuracy of the 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.

Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil, NGLs and natural gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify, positively or negatively, material revisions to the estimate of proved reserves.

Our estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which we record depletion expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of producing properties for impairment. For example, if the SEC prices used for our December 31, 2015 reserve report had been 10% less per Bbl and 10% less per MMBtu, respectively, then the standardized measure of our estimated proved reserves as of December 31, 2015 would have decreased by approximately $0.4 billion, from $1.3 billion to $0.9 billion.

Please see Part I—Item 1A "—Risk Factors" — "Risks Related to Our Business — Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves."

Asset Retirement Obligations

Estimated asset retirement obligation ("ARO") costs are recognized when the asset is placed in service and are amortized over proved reserves using the units of production method. Our engineers estimate asset retirement costs using existing regulatory requirements and anticipated future inflation rates. Projecting future ARO cost estimates is difficult as it involves the estimation of many variables such as economic recoveries of future oil and gas reserves, future labor and equipment rates, future inflation rates, and our credit adjusted risk free interest rate. Because of the intrinsic uncertainties present when estimating asset retirement costs as well as asset retirement settlement dates, our ARO estimates are subject to ongoing volatility.

Derivative Instruments

We use derivative financial instruments to achieve more predictable cash flow from our oil and natural gas production by reducing their exposure to price fluctuations. Currently, these instruments include swaps, collars and options. Additionally, we may use derivative financial instruments in the form of interest rate swaps to mitigate interest rate exposure. Derivative instruments (including certain derivative instruments embedded in other contracts) are recorded at fair market value and are included in the balance sheet as assets or liabilities. The accounting for changes in the fair market value of a derivative instrument depends on the intended use of the derivative instrument and the resulting designation, which is established at the inception of a derivative instrument. We do not account for our derivative instruments as cash flow hedges for financial accounting purposes and are recognizing changes in the fair value of our derivative instruments immediately in net income. See Part II—Item 7A "—Quantitative and Qualitative Disclosures About Market Risk" and Note 4 to the consolidated financial statements in this report for additional information related to our financial instruments.

Goodwill

We account for goodwill in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards. Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations.

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is not amortized, but is tested for impairment annually or whenever indicators of impairment exist and then charged to impairment expense. The analysis of the potential impairment of goodwill is a two-step process. Step one of the impairment test consists of comparing the fair value of the reporting unit with the aggregate carrying value, including goodwill. If the carrying value of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of goodwill impairment.

If the fair value of the reporting unit is less than its carrying value, step two of the goodwill impairment test is performed. Step two consists of comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. Determining the implied fair value of goodwill requires the valuation of a reporting unit's identifiable tangible and intangible assets and liabilities as if the reporting unit had been acquired in a business combination on the testing date. The fair value of the tangible and intangible assets and liabilities is based upon various assumptions including a discounted cash flow approach to value our oil and gas reserves (the "Income Approach"). The Income Approach valuation method requires projections of revenue and operating costs over a multi-year period. The valuation of assets and liabilities in step two is performed only for purposes of assessing goodwill for impairment.

As of March 31, 2015, we had $95.9 million of goodwill related to the 2014 QRE Merger (see Note 3). Due to a decrease in the price of our Common Units during the second quarter of 2015, we performed a qualitative goodwill impairment assessment. In the first step of the goodwill impairment test, we determined that the fair value of our goodwill was less than the carrying amount, primarily due to the decrease in the price of our Common Units. Therefore, we performed the second step of the goodwill impairment test, which led us to conclude that there was no remaining implied fair value attributable to goodwill. Based on this assessment, we recorded a non-cash goodwill impairment charge for the full amounts of the goodwill during the second quarter of 2015.

New Accounting Standards

See Note 2 to the consolidated financial statements within this report for a discussion of new accounting standards issued but not yet effective.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. See "*Cautionary Statement Regarding Forward-Looking Information"* in Part I—Item 1 "—Business" in this report.

See Note 4 to the consolidated financial statements in this report for additional information related to our financial instruments, including summaries of our commodity and interest rate derivative contracts at December 31, 2015 and a discussion of credit and counterparty risk.

Commodity Price Risk

Due to the historical volatility of oil and natural gas prices, we have entered into various derivative instruments to manage exposure to volatility in the market price of oil and natural gas to achieve more predictable cash flows. We use swaps, collars and options for managing risk relating to commodity prices. All contracts are settled with cash and do not require the delivery of physical volumes to satisfy settlement. While this strategy may result in us having lower revenues than we would otherwise have if we had not utilized these instruments in times of higher oil and natural gas prices, management believes that the resulting reduced volatility of prices and cash flow is beneficial. While our commodity price risk management program is intended to reduce our exposure to commodity prices and assist with stabilizing cash flow and distributions, to the extent we have hedged a significant portion of our expected production and the cost for goods and services increases, our margins would be adversely affected. Please see Part I—Item 1A "—Risk Factors" — "Risks Related to Our Business — Our derivative activities could result in financial losses or could reduce our income, which may adversely affect our ability to pay distributions to our unitholders. To the extent we have hedged a significant portion of our expected production and actual production is lower than expected or the costs of goods and services increase, our profitability would be adversely affected." The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts.

Our commodity derivative instruments other than our basis swaps provide for monthly settlement based on the differential between the agreement price and the actual ICE Brent oil price, NYMEX WTI oil price, NYMEX Henry Hub natural gas price or MichCon City-Gate natural gas price. Our basis swaps provide for monthly settlement based on the differential between Henry Hub and various points.

The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and natural gas prices realized in our operations. These variations often result in a lack of adequate correlation to enable these derivative instruments to qualify for cash flow hedges. Accordingly, we do not currently designate any of our derivative instruments as cash flow hedges for financial accounting purposes and instead recognize changes in fair value in earnings.

Our Permian Basin oil trades at a discount to WTI posted prices due to the deduction of transportation costs and our Permian Basin NGLs trade at a discount due to processing fees, profit sharing and transportation. Our Mid-Continent oil trades at a discount to WTI posted prices primarily due to transportation and quality, and our Mid-Continent NGLs trade at a discount due to regional market demand and transportation. Our Rockies oil, trades at a significant discount to WTI posted prices because of its distance from a major refining market and the fact that our central Wyoming production is priced relative to the Western Canadian Select benchmark. Our Southwestern Wyoming production is priced relative to Flint Hills Resources Wyoming Sweet posted prices. Our Ark-La-Tex oil trades at a premium to WTI posted prices due to local refinery market supply. Our oil from the Sunniland Trend in Florida trades at a discount to WTI posted prices primarily because this heavy crude is transported via barge to market. Our oil from the Jay Field in Florida trades at a discount to WTI posted prices due to transportation costs and quality. Our California oil is generally in proximity to the extensive Los Angeles refining market, and trades in accordance with that local market, which competes with waterborne crude imports.

In 2015, the WTI spot price averaged approximately $48 per Bbl, compared with approximately $93 in 2014. Monthly average WTI spot prices during 2015 ranged from a high of $60 per Bbl in June to a low of $37 per Bbl in December.

Our Michigan properties have favorable natural gas supply and demand characteristics due to their Northeastern US location, allowing us to sell our natural gas production at a slight premium to posted prices. Our Rockies area natural gas generally trades at a discount to NYMEX due to its relative location and the regional supply and demand market balances. Prices for natural gas have historically fluctuated widely and many regional markets are aligned with the local supply and demand conditions in those regional markets rather than with the overall U.S. market. Fluctuations in the price for natural gas in the United States are closely associated with the volumes produced in North America and the inventory in underground storage relative to customer demand. U.S. natural gas prices are also typically higher during the winter period when demand for heating is greatest.

All of our derivative instruments are recorded on the balance sheet at fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date, and/or confirmed by the counterparty. Changes in the fair value of our commodity derivatives were recorded in the "gain or loss on commodity derivative instruments, net" line on our consolidated statements of operations.

Interest Rate Risk

We are subject to interest rate risk associated with loans under our credit facility that bear interest based on floating rates. At December 31, 2015, LIBOR based long-term debt outstanding under our credit facility was $1.23 billion. In order to mitigate our interest rate exposure, we have various interest rate swaps to fix a portion of floating LIBOR based debt under our credit facility. For the year ended December 31, 2015, our weighted average credit facility debt balance was $1.53 billion and if interest rates on our LIBOR based debt increased or decreased by 100 basis points, our annual interest cost would have increased or decreased by approximately $15.3 million.

Changes in Fair Value

The fair value of our outstanding oil and gas commodity derivative instruments at December 31, 2015 and 2014 was a net asset of approximately $665.8 million and $727.2 million, respectively.

As of December 31, 2015, assuming a $10 per barrel increase in the price of oil and a corresponding $1 per Mcf increase in natural gas, our net commodity derivative instrument asset at December 31, 2015 would have decreased by approximately $206 million. Assuming a $10 per barrel decrease in the price of oil and a corresponding $1 per Mcf decrease in natural gas, our net commodity derivative instrument asset at December 31, 2015 would have increased by approximately $217 million.

Price risk sensitivities were calculated by assuming across-the-board increases in price of $10 per barrel for oil and $1 per Mcf for natural gas regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of actual changes in prompt month prices equal to the assumptions, the fair value of our derivative portfolio would typically change by less than the amounts given due to lower volatility in out-month prices.

The fair value of our outstanding interest rate derivative instruments was a net liability of approximately $4.1 million at December 31, 2015 compared to a net liability of approximately $7.2 million at December 31, 2014. With a 100 basis point increase in the LIBOR rate, our outstanding interest rate derivative instruments net liability at December 31, 2015 would have decreased by approximately $9.1 million. With a 100 basis points decrease in the LIBOR rate to a minimum rate of zero, our net liability at December 31, 2015 would have increased by approximately $9.2 million.

Item 8. Financial Statements and Supplementary Data.

The information required by this Item 8 is incorporated herein by reference from the consolidated financial statements beginning on page F-1.

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

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our General Partner's principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our General Partner's principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure, and that such information is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Commission. Based upon the evaluation, our General Partner's principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2015 at the reasonable assurance level.

Management's Report on Internal Control Over Financial Reporting

The information required by this Item is incorporated by reference from "Management's Report on Internal Control Over Financial Reporting" located on page F-2.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2015 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

There was no information required to be disclosed in a report on Form 8-K during the fourth quarter of 2015 that has not previously been reported.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Other than the information set forth hereunder, the information required by this Item is incorporated herein by reference to our definitive proxy statement for the 2016 Annual Meeting of Limited Partners ("2016 Proxy Statement"), which will be filed with the SEC not later than 120 days after December 31, 2015. The 2016 Annual Meeting of Limited Partners will be held on April 28, 2016.

Directors and Executive Officers of Breitburn GP LLC

The following table sets forth certain information with respect to the members of the board of directors and the executive officers of our General Partner. Executive officers and directors will serve until their successors are duly appointed or elected.

Name	Age	Position with Breitburn GP LLC
Halbert S. Washburn	55	Chief Executive Officer, Director
Mark L. Pease	59	President and Chief Operating Officer
James G. Jackson	51	Executive Vice President and Chief Financial Officer
Gregory C. Brown	64	Executive Vice President, General Counsel and Chief Administrative Officer
W. Jackson Washburn	53	Senior Vice President
Thomas E. Thurmond	42	Senior Vice President
Bruce D. McFarland	59	Vice President and Treasurer
Lawrence C. Smith	62	Vice President, Controller and Chief Accounting Officer
John R. Butler, Jr.*	77	Chairman of the Board
Randall H. Breitenbach	55	Vice Chairman of the Board
David B. Kilpatrick*	66	Director
Gregory J. Moroney*	64	Director
Kurt A. Talbot	54	Director
Charles S. Weiss*	63	Director
Donald D. Wolf*	72	Director

* Independent Directors

Item 11. Executive Compensation.

The information required by this Item is incorporated herein by reference to the 2016 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2015.

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

The information required by this Item is incorporated herein by reference to the 2016 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2015.

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

The information required by this Item is incorporated herein by reference to the 2016 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2015.

Item 14. Principal Accounting Fees and Services.

The information required by this Item is incorporated herein by reference to the 2016 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2015.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) (1) Financial Statements

See “Index to the Consolidated Financial Statements” set forth on Page F-1.

(a) (2) Financial Statement Schedules

All schedules are omitted because they are not applicable or the required information is presented in the consolidated financial statements or notes thereto.

(a) (3) Exhibits

The information in the Exhibit Index of this Annual Report on Form 10-K is incorporated in this Item 15(a)(3) by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BREITBURN ENERGY PARTNERS LP

By: BREITBURN GP LLC,
its General Partner

Dated: February 26, 2016

By: /s/ Halbert S. Washburn
Halbert S. Washburn
Chief Executive 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 the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ Halbert S. Washburn **Halbert S. Washburn**	Chief Executive Officer and Director of Breitburn GP LLC (Principal Executive Officer)	February 26, 2016
/s/ James G. Jackson **James G. Jackson**	Chief Financial Officer of Breitburn GP LLC (Principal Financial Officer)	February 26, 2016
/s/ Lawrence C. Smith **Lawrence C. Smith**	Vice President, Controller and Chief Accounting Officer Breitburn GP LLC (Principal Accounting Officer)	February 26, 2016
/s/ John R. Butler, Jr. **John R. Butler, Jr.**	Chairman of the Board of Breitburn GP LLC	February 26, 2016
/s/ Randall H. Breitenbach **Randall H. Breitenbach**	Vice Chairman of the Board Breitburn GP LLC	February 26, 2016
/s/ David B. Kilpatrick **David B. Kilpatrick**	Director of Breitburn GP LLC	February 26, 2016
/s/ Gregory J. Moroney **Gregory J. Moroney**	Director of Breitburn GP LLC	February 26, 2016
/s/ Charles S. Weiss **Charles S. Weiss**	Director of Breitburn GP LLC	February 26, 2016
/s/ Donald D. Wolf **Donald D. Wolf**	Director of Breitburn GP LLC	February 26, 2016
/s/ Kurt A. Talbot **Kurt A. Talbot**	Director of Breitburn GP LLC	February 26, 2016

BREITBURN ENERGY PARTNERS LP AND SUBSIDIARIES
INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control Over Financial Reporting

The management of Breitburn Energy Partners LP (the "Partnership") is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). The term "internal control over financial reporting" is defined as a process designed by, or under the supervision of, the Partnership's principal executive and principal financial officers, or persons performing similar functions, and effected by the Partnership's board of directors, management and other personnel, 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 and includes those policies and procedures that: (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Partnership; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorizations of management and directors of the Partnership; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Partnership's assets that could have a material effect on the financial statements.

Internal control over financial reporting, no matter how well designed, has inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

As required by Rule 13a-15(c) under the Exchange Act, the Partnership's management, with the participation of our General Partner's principal executive officers and principal financial officer, assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2015. In making this assessment, the Partnership's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework* (2013). Based on this assessment, the Partnership's management, including our General Partner's principal executive officer and principal financial officer, concluded that, as of December 31, 2015, the Partnership's internal control over financial reporting was effective based on those criteria.

PricewaterhouseCoopers LLP, the independent registered public accounting firm who audited the consolidated financial statements included in this Annual Report on Form 10-K, has also audited the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2015, which appears on page F-3.

/s/ Halbert S. Washburn
Halbert S. Washburn
Chief Executive Officer of Breitburn GP LLC

/s/ James G. Jackson
James G. Jackson
Chief Financial Officer of Breitburn GP LLC

Report of Independent Registered Public Accounting Firm

To the Board of Directors of Breitburn GP LLC and
Unitholders of Breitburn Energy Partners LP

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, comprehensive (loss) income, partners' equity and cash flows present fairly, in all material respects, the financial position of Breitburn Energy Partners LP and its subsidiaries at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2, the Partnership's credit facility is subject to borrowing base redeterminations in 2016, which could require significant principal repayments.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Los Angeles, California
February 26, 2016

Breitburn Energy Partners LP and Subsidiaries
Consolidated Balance Sheets

Thousands of dollars	December 31, 2015	December 31, 2014
ASSETS		
Current assets		
Cash	$ 10,464	$ 12,628
Accounts and other receivables, net (note 2)	128,589	166,436
Derivative instruments (note 4)	439,627	408,151
Related party receivables (note 5)	2,274	2,462
Inventory	926	3,727
Prepaid expenses	6,447	7,304
Total current assets	588,327	600,708
Equity investments	6,567	6,463
Property, plant and equipment		
Oil and natural gas properties (note 3)	7,898,117	7,736,409
Other property, plant and equipment (note 3)	188,795	60,533
	8,086,912	7,796,942
Accumulated depletion, depreciation and impairment (note 6)	(4,154,030)	(1,342,741)
Net property, plant and equipment	3,932,882	6,454,201
Other long-term assets		
Goodwill (note 3)	—	92,024
Derivative instruments (note 4)	226,764	319,560
Other long-term assets (note 8)	117,872	165,378
Total assets	$ 4,872,412	$ 7,638,334
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 50,412	$ 129,270
Current portion of long-term debt (note 9)	154,000	105,000
Derivative instruments (note 4)	4,462	5,457
Distributions payable	733	733
Current asset retirement obligation	2,341	4,948
Revenue and royalties payable	35,462	40,452
Wages and salaries payable	21,654	22,322
Accrued interest payable	19,517	20,672
Production and property taxes payable	24,292	25,207
Other current liabilities	5,133	7,495
Total current liabilities	318,006	361,556
Credit facility (note 9)	1,075,000	2,089,500
Senior notes, net (note 9)	1,789,219	1,156,560
Other long-term debt (note 9)	2,938	1,100
Total long-term debt (note 9)	2,867,157	3,247,160
Deferred income taxes (note 11)	3,844	2,575
Asset retirement obligation (note 12)	252,037	233,463
Derivative instruments (note 4)	255	2,269
Other long-term liabilities	25,218	25,135
Total liabilities	3,466,517	3,872,158
Commitments and contingencies (note 14)		
Equity:		
Series A cumulative redeemable preferred units, 8.0 million units issued and outstanding at December 31, 2015 and December 31, 2014 (note 15)	193,215	193,215
Series B perpetual convertible preferred units, 48.8 million and 0 units issued and outstanding at December 31, 2015 and December 31, 2014, respectively (note 15)	353,471	—
Common units, 213.5 million and 210.9 million units issued and outstanding at December 31, 2015 and December 31, 2014, respectively (note 15)	852,114	3,566,468
Accumulated other comprehensive loss (note 16)	(229)	(392)
Total partners' equity	1,398,571	3,759,291
Noncontrolling interest (note 17)	7,324	6,885
Total equity	1,405,895	3,766,176
Total liabilities and equity	$ 4,872,412	$ 7,638,334

The accompanying notes are an integral part of these consolidated financial statements.

Breitburn Energy Partners LP and Subsidiaries
Consolidated Statements of Operations

Thousands of dollars, except per unit amounts	Year Ended December 31, 2015	2014	2013
Revenues and other income items:			
Oil, natural gas and natural gas liquid sales	$ 645,272	$ 855,820	$ 660,665
Gain (loss) on commodity derivative instruments, net (note 4)	438,614	566,533	(29,182)
Other revenue, net	24,829	7,616	3,175
Total revenues and other income items	1,108,715	1,429,969	634,658
Operating costs and expenses:			
Operating costs	455,189	355,681	262,822
Depletion, depreciation and amortization	460,047	291,709	216,495
Impairments of oil and natural gas properties (note 6)	2,377,615	149,000	54,373
Impairment of goodwill (note 6)	95,947	—	—
General and administrative expenses	98,999	86,949	58,707
Restructuring costs (note 21)	6,364	—	—
(Gain) loss on sale of assets (note 3)	(8,864)	663	(2,015)
Total operating costs and expenses	3,485,297	884,002	590,382
Operating (loss) income	(2,376,582)	545,967	44,276
Interest expense, net of capitalized interest (note 9)	203,027	126,960	87,067
Loss (gain) on interest rate swaps (note 4)	2,691	(490)	—
Other expense (income), net	(814)	(1,746)	(25)
(Loss) income before taxes	(2,581,486)	421,243	(42,766)
Income tax expense (benefit) (note 11)	1,527	(73)	905
Net (loss) income	(2,583,013)	421,316	(43,671)
Less: Net income (loss) attributable to noncontrolling interest (note 17)	326	(17)	—
Net (loss) income attributable to the partnership	(2,583,339)	421,333	(43,671)
Less: Distributions to Series A preferred unitholders	16,500	10,083	—
Less: Non-cash distributions to Series B preferred unitholders	20,817	—	—
Less: Net income (loss) attributable to participating units	—	5,348	—
Less: Distributions on participating units in excess of earnings	1,731	—	—
Net (loss) income used to calculate basic and diluted net (loss) income per unit	$ (2,622,387)	$ 405,902	$ (43,671)
Basic net (loss) income per unit (note 15)	$ (12.39)	$ 3.04	$ (0.43)
Diluted net (loss) income per unit (note 15)	$ (12.39)	$ 3.02	$ (0.43)
Weighted average number of units used to calculate basic and diluted net (loss) income per unit (in thousands):			
Basic	211,575	133,451	101,604
Diluted	211,575	134,206	101,604

The accompanying notes are an integral part of these consolidated financial statements.

Breitburn Energy Partners LP and Subsidiaries
Consolidated Statements of Comprehensive (Loss) Income

Thousands of dollars, except per unit amounts	Year Ended December 31, 2015	2014	2013
Net (loss) income	$ (2,583,013)	$ 421,316	$ (43,671)
Other comprehensive income (loss), net of tax:			
Change in fair value of available-for-sale securities (a)	(402)	(189)	—
Pension and post-retirement benefits actuarial gain (loss) (b)	677	(473)	—
Total other comprehensive income (loss), net of tax	275	(662)	—
Total comprehensive (loss) income	(2,582,738)	420,654	(43,671)
Less: Comprehensive income (loss) attributable to noncontrolling interest	438	(287)	—
Comprehensive (loss) income attributable to the partnership	$ (2,583,176)	$ 420,941	$ (43,671)

(a) Net of income taxes of $0.3 million and $0.1 million for the years ended December 31, 2015 and 2014, respectively.
(b) Net of income tax (benefit) expense of $(0.1) million and $0.2 million for the years ended December 31, 2015 and 2014, respectively.

The accompanying notes are an integral part of these consolidated financial statements.

Breitburn Energy Partners LP and Subsidiaries
Consolidated Statements of Cash Flows

Thousands of dollars	Year Ended December 31, 2015	2014	2013
Cash flows from operating activities			
Net (loss) income	$ (2,583,013)	$ 421,316	$ (43,671)
Adjustments to reconcile to cash flow from operating activities:			
Depletion, depreciation and amortization	460,047	291,709	216,495
Impairments of oil and natural gas properties	2,377,615	149,000	54,373
Impairment of goodwill	95,947	—	—
Unit-based compensation expense	26,805	23,387	19,955
(Gain) loss on derivative instruments	(435,923)	(567,024)	29,182
Derivative instrument settlement receipts	494,234	26,806	8,083
Income from equity affiliates, net	(104)	178	(55)
Deferred income taxes	1,269	(174)	262
(Gain) loss on sale of assets	(8,864)	663	(2,015)
Other	16,142	6,204	5,163
Changes in net assets and liabilities:			
Accounts receivable and other assets	35,367	41,754	(29,322)
Inventory	2,801	163	(804)
Net change in related party receivables and payables	188	142	(1,191)
Accounts payable and other liabilities	(45,806)	(36,369)	711
Net cash provided by operating activities	436,705	357,755	257,166
Cash flows from investing activities			
Property acquisitions, net of cash acquired (note 3)	(18,201)	(401,465)	(1,175,817)
Capital expenditures	(269,350)	(417,755)	(266,308)
Proceeds from sale of assets	14,547	499	2,981
Proceeds from sale of available-for-sale securities	3,875	—	—
Purchases of available-for-sale securities	(4,021)	—	—
Other	(853)	(18,283)	(26,661)
Net cash used in investing activities	(274,003)	(837,004)	(1,465,805)
Cash flows from financing activities			
Proceeds from issuance of preferred units, net	337,238	193,215	—
Proceeds from issuance of common units, net	3,008	277,613	618,013
Distributions to preferred unitholders	(16,502)	(9,350)	—
Distributions to common unitholders	(126,188)	(264,585)	(186,868)
Proceeds from issuance of long-term debt, net	1,378,338	2,457,600	2,276,000
Repayments of long-term debt	(1,711,500)	(1,785,000)	(1,487,000)
Senior note redemption	—	(352,531)	—
Change in bank overdraft	11	(2,434)	2,013
Debt issuance costs	(29,271)	(25,109)	(15,568)
Net cash (used in) provided by financing activities	(164,866)	489,419	1,206,590
(Decrease) increase in cash	(2,164)	10,170	(2,049)
Cash beginning of period	12,628	2,458	4,507
Cash end of period	$ 10,464	$ 12,628	$ 2,458

The accompanying notes are an integral part of these consolidated financial statements.

Breitburn Energy Partners LP and Subsidiaries
Consolidated Statements of Partners' Equity

	Units							
Thousands	**Preferred Series A**	**Preferred Series B**	**Common**	**Preferred Series A**	**Preferred Series B**	**Common**	**Accumulated Other Comprehensive Loss**	**Partner's Equity**
Balance, December 31, 2012	—	—	84,668	$ —	$ —	$1,589,536	$ —	$ 1,589,536
Sales of common units	—	—	33,925	—	—	617,752	—	617,752
Distributions on common units	—	—	—	—	—	(183,594)	—	(183,594)
Common units issued under incentive plans	—	—	577	—	—	12,421	—	12,421
Distributions paid on unissued units under incentive plans	—	—	—	—	—	(3,274)	—	(3,274)
Unit-based compensation	—	—	—	—	—	650	—	650
Net loss attributable to the partnership	—	—	—	—	—	(43,671)	—	(43,671)
Balance, December 31, 2013	—	—	**119,170**	—	—	**1,989,820**	—	**1,989,820**
Sales of Series A preferred units	8,000	—	—	193,215	—	—	—	193,215
Sales of common units	—	—	15,272	—	—	277,605	—	277,605
Distributions on Series A preferred units	—	—	—	(10,083)	—	—	—	(10,083)
Distributions on common units	—	—	—	—	—	(260,958)	—	(260,958)
Common units issued for acquisitions	—	—	75,837	—	—	1,131,146	—	1,131,146
Common units issued under incentive plans	—	—	615	—	—	17,985	—	17,985
Distributions paid on unissued units under incentive plans	—	—	—	—	—	(3,626)	—	(3,626)
Unit-based compensation	—	—	—	—	—	3,246	—	3,246
Net income attributable to the partnership	—	—	—	10,083	—	411,250	—	421,333
Other comprehensive loss	—	—	—	—	—	—	(392)	(392)
Balance, December 31, 2014	**8,000**	—	**210,894**	**193,215**	—	**3,566,468**	**(392)**	**3,759,291**
Sales of Series B preferred units	—	46,667	—	—	337,238	—	—	337,238
Sales of common units	—	—	544	—	—	3,115	—	3,115
Distributions on Series A preferred units	—	—	—	(16,500)	—	—	—	(16,500)
Distributions paid-in-kind Series B preferred units	—	2,164	—	—	—	—	—	—
Distributions paid-in-kind common units	—	—	448	—	(3,359)	3,359	—	—
Distributions payable on Series B preferred units	—	—	—	—	(1,225)	—	—	(1,225)
Distributions on common units	—	—	—	—	—	(123,217)	—	(123,217)
Common units issued under incentive plans	—	—	1,595	—	—	28,500	—	28,500
Distributions paid on unissued units under incentive plans	—	—	—	—	—	(2,971)	—	(2,971)
Unit-based compensation	—	—	—	—	—	(2,484)	—	(2,484)
Net loss attributable to the partnership	—	—	—	16,500	20,817	(2,620,656)	—	(2,583,339)
Other comprehensive income	—	—	—	—	—	—	163	163
Balance, December 31, 2015	**8,000**	**48,831**	**213,481**	**$ 193,215**	**$ 353,471**	**$ 852,114**	**$ (229)**	**$ 1,398,571**

The accompanying notes are an integral part of these consolidated financial statements.

Notes to Consolidated Financial Statements

1. Organization

Organization

We are a Delaware limited partnership formed on March 23, 2006. Our initial public offering was in October 2006. Pacific Coast Energy Company LP ("PCEC"), formerly Breitburn Energy Company LP, is our Predecessor.

Our general partner is Breitburn GP LLC, a wholly-owned Delaware limited liability company (the "General Partner"), also formed on March 23, 2006. The board of directors of our General Partner has sole responsibility for conducting our business and managing our operations. We conduct our operations through a wholly-owned subsidiary, Breitburn Operating LP, ("BOLP"), BOLP's general partner, Breitburn Operating GP LLC ("BOGP"), and through BOLP's operating subsidiaries.

On November 19, 2014, we completed the transactions contemplated by the Agreement and Plan of Merger, dated as of July 23, 2014 (the "Merger Agreement") with QR Energy, LP, a Delaware limited partnership ("QRE"). Pursuant to the terms of the Merger Agreement, QRE merged with a subsidiary of the Partnership, with QRE continuing as the surviving entity and as a direct wholly owned subsidiary of the Partnership (the "QRE Merger"). Immediately thereafter, the Partnership transferred 100% of the limited partner interests of QRE to BOLP. In connection with the QRE Merger, we acquired a controlling interest in East Texas Salt Water Disposal Company ("ETSWDC"), a privately held Texas corporation. The main purpose of ETSWDC is to dispose of salt water generated as a by-product from oil produced in certain East Texas oil fields. See Note 3 for more information.

Our wholly owned subsidiary, Breitburn Management Company LLC ("Breitburn Management"), manages our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. See Note 5 for information regarding our relationship with Breitburn Management. Our wholly-owned subsidiary, Breitburn Finance Corporation ("Breitburn Finance"), was incorporated on June 1, 2009 under the laws of the State of Delaware. Breitburn Finance has no assets or liabilities, and its activities are limited to co-issuing debt securities and engaging in other activities incidental thereto. Our wholly-owned subsidiary, Breitburn Collingwood Utica LLC ("Breitburn Utica"), holds certain non-producing oil and gas zones in the Collingwood-Utica shale play in Michigan and is classified as an unrestricted subsidiary under our credit facility. We own 100% of our General Partner, BOLP, Breitburn Management, Breitburn Finance and Breitburn Utica.

2. Summary of Significant Accounting Policies

Principles of consolidation and basis of presentation

The consolidated financial statements include our accounts and the accounts of our wholly-owned subsidiaries. Investments in affiliated companies with a 20% or greater ownership interest, and in which we have significant influence but do not have control, are accounted for on an equity basis. Investments in affiliated companies with less than a 20% ownership interest, and in which we do not have control, are accounted for on the cost basis. Investments in which we own greater than a 50% interest and in which we have control are consolidated. Investments in which we own less than a 50% interest but are deemed to have control, or where we have a variable interest in an entity in which we will absorb a majority of the entity's expected losses or receive a majority of the entity's expected residual returns or both, however, are consolidated.

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2015 and 2014. These financial statements also include the results of our operations, our changes in comprehensive income (loss), changes in partners' capital and cash flows for the years ended December 31, 2015, 2014, and 2013.

These consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP"). All intercompany accounts and transactions have been eliminated in consolidation. In addition, we assume realization of assets and settlement of liabilities in the normal course of business.

We recognized net loss attributable to the partnership of $2.58 billion and cash provided by operations was $436.7 million for the year ended December 31, 2015 and had cash on hand of $10.5 million at December 31, 2015.

As of December 31, 2015, we had approximately $1.2 billion in borrowings under our credit facility, including $154 million classified as a current liability, and $25.8 million in letters of credit outstanding. Our credit facility limits the amounts we can borrow to a borrowing base amount determined by the lenders at their sole discretion based on their valuation of our proved reserves and their internal criteria (see Note 9 for further discussion of our borrowing base). The borrowing base at December 31, 2015 was $1.8 billion and the next semi-annual redetermination is scheduled for April 2016. Based upon current commodity prices and other factors at the time of future redeterminations, we expect our borrowing base to be significantly decreased. Without a waiver from our lenders, our credit facility currently provides that if the borrowing base is reduced below our current outstanding borrowings, we are required to repay the deficiency in five equal monthly installments. Although our lenders have the discretion to redetermine the borrowing base below our current outstanding borrowings, we do not expect that to occur in April 2016. However, if commodity prices remain depressed or further decline, we expect our borrowing base to be reduced again at the subsequent borrowing base redetermination in October 2016, which could further impact and limit our liquidity.

We believe our existing cash resources and hedge positions should provide us with sufficient funds to meet our expected working capital needs for 2016, assuming that our borrowing base is redetermined above our current outstanding borrowings. Although we currently expect our sources of capital to be sufficient to meet our near-term liquidity needs, there can be no assurance that the lenders under our credit facility will not reduce the borrowing base to an amount below our current outstanding borrowings in April or at the October 2016 redetermination or that our liquidity requirements will continue to be satisfied, given current oil prices and the discretion of our lenders to decrease our borrowing base. Due to the steep decline in commodity prices and the trading prices of our debt and equity securities, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable. The cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, and reduced and, in many cases, ceased to provide any new funding. We expect that we will take other actions to raise funds to repay debt, such as selling non-core assets or restructuring derivative contracts.

As a result of both the low commodity price environment and our substantial debt burden, our liquidity will remain limited absent a material improvement in oil and natural gas prices or a refinancing or restructuring of our balance sheet debt. We may engage financial and legal advisors to advise our management and our Board of Directors regarding potential strategic alternatives such as a refinancing or restructuring of our indebtedness or capital structure or seeking to raise additional capital through debt or equity financing to address our leverage and liquidity issues. We are also focused on cost reductions and the identification of non-core assets for potential sale. We cannot give any assurances that any of these efforts will be possible on acceptable terms or will be successful or result in actual cost reductions or additional cash flows or the timing of any such potential results.

Use of estimates

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The financial statements are based on a number of significant estimates including acquisition purchase price allocations, debt subject to acceleration, fair value of derivative instruments, unit-based compensation, pension and post-retirement obligations, future cash flow from oil, NGL and natural gas properties and oil, NGL and natural gas reserve quantities, which are the basis for the calculation of depletion, depreciation and amortization ("DD&A"), asset retirement obligations and impairment of oil, NGL and natural gas properties and goodwill.

Business segment information

We report our operations in one segment because our oil and gas operating areas have similar economic characteristics. We acquire, exploit, develop and produce oil and natural gas in the United States. Corporate management administers all properties as a whole rather than as discrete operating segments. Operational data is tracked by area; however, financial performance is measured as a single enterprise and not on an area-by-area basis. Allocation of capital resources is employed on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas.

Cash and cash equivalents

We consider all highly liquid investments with an original maturity of three months or less at the time of purchase to be cash equivalents. Our cash and cash equivalents consist of cash in banks and investments in money market accounts. The majority of cash and cash equivalents are maintained with a major financial institution in the United States. Deposits with these financial institutions may exceed the amount of insurance provided on such deposits; however, we regularly monitor the financial stability of these financial institutions and believe that we are not exposed to any significant default risk.

Accounts receivable

Our accounts receivable are primarily from purchasers of oil and natural gas and counterparties to our financial instruments. Oil receivables are generally collected within 30 days after the end of the month. Natural gas receivables are generally collected within 60 days after the end of the month. We review all outstanding accounts receivable balances and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At December 31, 2015 and 2014, we had an allowance for doubtful accounts receivable of $2.1 million and $1.6 million, respectively.

Inventory

Our inventory consists of oil held in storage tanks related to our Florida operations pending shipment by barge to the point of sale. Oil inventories are carried at the lower of cost to produce or market price. We match production expenses with oil sales. Production expenses associated with unsold oil inventory are recorded as inventory. When using lower of cost or market to value inventory, market is the net realizable value or the estimated selling price less costs of completion and disposal. We assessed our crude oil inventory at December 31, 2015 and December 31, 2014 and we recognized write-downs of $0.6 million and $1.0 million, respectively.

Property, plant and equipment

Oil and natural gas properties

We follow the successful efforts method of accounting. Lease acquisition and development costs (tangible and intangible) incurred relating to proved oil and gas properties are capitalized. Delay and surface rentals are charged to expense as incurred. Dry hole costs incurred on exploratory wells are expensed. Dry hole costs associated with developing proved fields are capitalized. Geological and geophysical costs related to exploratory operations are expensed as incurred.

We carry out tertiary recovery methods on certain of our oil and gas properties in order to recover additional hydrocarbons that are not recoverable from primary or secondary recovery methods. Acquisition costs of tertiary injectants, such as purchased CO_2, for enhanced oil recovery activities that are used prior to the recognition of proved tertiary recovery reserves are expensed as incurred. After a project has been determined to be technically feasible and economically viable, all acquisition costs of tertiary injectants are capitalized as development costs and depleted, as they are incurred solely for obtaining access to reserves not otherwise recoverable and have future economic benefits over the life of the project. As CO_2 is recovered together with oil and gas production, it is extracted and re-injected, and all the associated CO_2 recycling costs are expensed as incurred. Likewise, other costs incurred to maintain reservoir pressure are also expensed.

Upon sale or retirement of proved properties, the cost thereof and the DD&A are removed from the accounts and any gain or loss is recognized in the statement of operations. Maintenance and repairs are charged to operating expenses. DD&A of proved oil and gas properties, including the estimated cost of future abandonment and restoration of well sites and associated facilities, is generally computed on a field-by-field basis where applicable and recognized using the units of production method net of any anticipated proceeds from equipment salvage and sale of surface rights. Other gathering and processing facilities are recorded at cost and are depreciated using the straight-line method over their estimated useful lives, generally over 20 years.

We capitalize interest costs to oil and gas properties on expenditures made in connection with major projects and the drilling and completion of new oil and natural gas wells. Interest is capitalized only for the period that such activities are in progress. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using the units of production method. During 2015, 2014 and 2013, interest of $0.2 million, $0.3 million and $0.1 million, respectively, was capitalized and included in our capital expenditures.

Non-oil and natural gas assets

Buildings and non-oil and gas assets, including property and equipment related to the disposal of salt water at our East Texas fields, are recorded at cost and depreciated using the straight-line method over their estimated useful lives, which range from three to 25 years.

In March 2015, we acquired certain CO_2 producing properties located in Harding County, New Mexico for the purpose of accessing CO_2 reserves for our tertiary activities ("CO_2 Assets"). See Note 3 for more information. The lease acquisition and development costs (tangible and intangible) incurred relating to CO_2 Assets are capitalized. Lease acquisition and any additional development costs are depleted using the units of production method and the tangible equipment are depreciated on a straight-line method over 40 years.

Oil and natural gas reserve quantities

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion are made concurrently with changes to reserve estimates. We disclose reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with the Securities and Exchange Commission (the "SEC") guidelines. The independent engineering firms adhere to the SEC definitions when preparing their reserve reports.

Investments

Investments consist of debt and equity securities, all of which are classified as available-for-sale and stated at fair value on our consolidated balance sheet. Accordingly, unrecognized changes in fair value and the related deferred tax effect are excluded from earnings and reported as a separate component within our consolidated statement of other comprehensive income. Changes in fair value of securities sold are computed based on the specific identification of the securities sold, and are reclassified from other comprehensive income into earnings (reflected in other expense (income), net on the consolidated statements of operations) in the period sold.

Pensions and Other Postretirement Benefits

We recognize the overfunded or underfunded status of the pension and postretirement benefit plans as either assets or liabilities on our consolidated balance sheet. A plan's funded status is the difference between the fair value of the plan assets and the plan's benefit obligation. The plan's benefit obligation is based on estimates using management's best estimate and judgments which includes independent actuarial service assumptions to determine the plan obligation. We record the plan's cost and income – unrecognized losses and gains, unrecognized prior service costs and credits and transition obligations, if any – in our consolidated statement of other comprehensive income until they are amortized into earnings as a component of benefit costs.

Debt issuance costs

The costs incurred to obtain financing have been capitalized. Debt issuance costs are charged to interest expense over the term of the related debt instrument. With the implementation of Accounting Standards Update ASU 2015-03, *Simplifying the Presentation of Debt Issuance Costs*, unamortized debt issuance costs associated with our outstanding Senior Notes (as defined below), which were formerly presented as a component of Other long-term assets, will be shown as a reduction to the carrying liability amount of our Senior Notes.

Asset retirement obligations

We have significant obligations to plug and abandon oil, natural gas and saltwater disposal wells and related equipment at the end of oil and natural gas production operations or salt water disposal operations. The fair value of a liability for an asset retirement obligation ("ARO") is recorded when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. Over time, changes in the present value of the liability are accreted and recorded as part of DD&A on the consolidated statements of operations. The capitalized asset costs are depreciated over the useful lives of the corresponding asset. Recognized liability amounts are based upon future retirement cost estimates and incorporate many assumptions such as: (1) expected economic recoveries of oil and natural gas, (2) time to abandonment, (3) future inflation rates and (4) the risk free rate of interest adjusted for our credit costs. Future revisions to ARO estimates will impact the present value of existing ARO liabilities and corresponding adjustments will be made to the capitalized asset retirement costs balance.

Revenue recognition

We recognize revenue when it is realized or realizable and earned. Revenues are considered realized or realizable and earned when: (i) persuasive evidence of an arrangement exists, (ii) delivery has occurred, (iii) the seller's price to the buyer is fixed or determinable and (iv) collectability is reasonably assured.

Revenues from properties in which we have an interest with other partners are recognized on the basis of our working interest ("entitlement" method of accounting). We generally market most of our natural gas production from our operated properties and pay our partners for their working interest shares of natural gas production sold. As of December 31, 2015 and 2014, our natural gas producer imbalance liability was $11.4 million and $11.5 million, respectively, reflected in other long-term liabilities on the consolidated balance sheets.

Impairments

Long-lived assets and finite lived intangible assets with recorded values that are not expected to be recovered through future cash flows are written down to estimated fair value. A long-lived asset or finite lived intangible asset is tested for impairment periodically and when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset or finite lived intangible asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows. For purposes of performing an impairment test, the undiscounted future cash flows are based on total proved and risk-adjusted probable and possible reserves, and are forecast using five-year NYMEX forward strip prices at the end of the period and escalated along with expenses and capital starting year six and thereafter at 2% per year. Production and development cost estimates (e.g. operating expenses and development capital) are conformed to reflect the commodity price strip used where applicable. For impairment charges, the associated property's expected future net cash flows were discounted using a long-term weighted average cost of capital which approximated 10% at December 31, 2015. Reserves are calculated based upon reports from third party engineers adjusted for acquisitions or other changes occurring during the year as determined to be appropriate in the good faith judgment of management. Unproved 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. We assess our long-lived assets for impairment generally on a field-by-field basis where applicable. See Note 6 for a discussion of impairments of oil, NGL and natural gas assets.

We account for goodwill in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards. Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations.

Goodwill is not amortized, but is tested for impairment annually or whenever indicators of impairment exist and charged to impairments. The analysis of the potential impairment of goodwill is a two step process. Step one of the impairment test consists of comparing the fair value of the reporting unit with the aggregate carrying value, including goodwill. If the carrying value of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of the goodwill impairment. Step two of the goodwill impairment test consists of comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. Determining the implied fair value of goodwill requires the valuation of a reporting unit's identifiable tangible and intangible assets and liabilities as if the reporting unit had been acquired in a business combination on the testing date. The fair value of the tangible and intangible assets and liabilities is based upon various assumptions including a discounted cash flow approach to value our oil and gas reserves (the "Income Approach"). The Income Approach valuation method requires projections of revenue and operating costs over a multi-year period. The valuation of assets and liabilities in step two is performed only for purposes of assessing goodwill for impairment.

Equity-based compensation

Breitburn Management has various forms of equity-based compensation outstanding under employee compensation plans that are described more fully in Note 18. Awards classified as equity are valued on the grant date and are recognized as compensation expense over the vesting period, which is part of the general and administrative ("G&A") expenses line on the consolidated statements of operations. We recognize equity-based compensation costs on a straight line basis over the requisite service periods.

Fair market value of financial instruments

The carrying amount of our cash, accounts receivable, accounts payable, related party receivables and payables and accrued expenses approximate their respective fair value due to the relatively short term of the related instruments. The carrying amount of long-term debt under our credit facility approximates fair value; however, changes in the credit markets may impact our ability to enter into future credit facilities at similar terms. See Note 9 for the fair value of our Senior Notes.

Accounting for business combinations

We account for all business combinations using the acquisition method. Under the acquisition method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given, whether in the form of cash, assets, equity or the assumption of liabilities. The assets acquired and liabilities assumed are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if material, is recognized as a gain at the time of acquisition. Similarly, the deficit of the fair value of assets acquired and liabilities assumed under the cost of an acquired entity, if material, is recognized as goodwill at the time of acquisition. All purchase price allocations are finalized within one year from the acquisition date.

There was no goodwill recognized for 2015 acquisitions. We recognized $95.9 million of goodwill as part of the final purchase price related to the 2014 QRE Merger, which became fully impaired in 2015.

Concentration of credit risk

We maintain our cash accounts primarily with a single bank and invest cash in money market accounts, which we believe to have minimal risk. At times, such balances may be in excess of the Federal Insurance Corporation insurance limit. As operator of jointly owned oil and gas properties, we sell oil and gas production to U.S. oil and gas purchasers and pay vendors on behalf of joint owners for oil and gas services. We periodically monitor our major purchasers' credit ratings. We enter into commodity and interest rate derivative instruments. Our derivative counterparties are all lenders under our credit facility, and we periodically monitor their credit ratings.

For our properties in Florida, there are a limited number of alternative methods of transportation for our production. Substantially all of our crude oil production is transported by pipelines, trucks and barges owned by third parties. The inability or unwillingness of these parties to provide transportation services for a reasonable fee could result in our having to find transportation alternatives, increased transportation costs or involuntary curtailment of our crude oil production, which could have a negative impact on our future consolidated financial position, results of operations and cash flows.

Derivatives

FASB Accounting Standards establish accounting and reporting requirements for derivative instruments, including certain derivative instruments embedded in other contracts, and hedging activities. These standards require recognition of all derivative instruments as assets or liabilities on our balance sheet and measurement of those instruments at fair value. The accounting treatment of changes in fair value is dependent upon whether or not a derivative instrument is designated as a hedge and if so, the type of hedge. We currently do not designate any of our derivatives as hedges for financial accounting purposes. Gains and losses on derivative instruments not designated as hedges are currently included in earnings. The resulting cash flows are reported as cash from operating activities.

Fair value measurement is based upon a hypothetical transaction to sell an asset or transfer a liability at the measurement date. The objective of fair value measurement is to determine the price that would be received in selling the asset or transferring the liability in an orderly transaction between market participants at the measurement date. If we have a principal market for the asset or liability, the fair value measurement shall represent the price in that market, otherwise the price will be determined based on the most advantageous market. See Note 4 for detail on our derivative instruments.

Income taxes

Our subsidiaries are mostly partnerships or limited liability companies treated as partnerships for federal tax purposes with essentially all taxable income or loss being passed through to the members. As such, no federal income tax for these entities has been provided.

We have three wholly-owned subsidiaries and a controlling interest in an additional subsidiary that are subject to corporate income taxes. Deferred income taxes are recorded under the asset and liability method. Where material, deferred income tax assets and liabilities are computed for differences between the financial statement and income tax bases of assets and liabilities that will result in taxable or deductible amounts in the future. Such deferred income tax asset and liability computations are based on enacted tax laws and rates applicable to periods in which the differences are expected to affect taxable income. Income tax expense is the tax payable or refundable for the period plus or minus the change during the period in deferred income tax assets and liabilities.

FASB Accounting Standards clarify the accounting for uncertainty in income taxes recognized in a company's financial statements. A company can only recognize an uncertain tax position in the financial statements if the position is more-likely-than-not to be upheld on audit based only on the technical merits of the tax position. This accounting standard also provides guidance on thresholds, measurement, derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition that is intended to provide better financial-statement comparability among different companies.

We performed an analysis as of December 31, 2015 and 2014 and concluded that there were no uncertain tax positions requiring recognition in our financial statements.

Net income or loss per unit

FASB Accounting Standards require use of the "two-class" method of computing earnings per unit for all periods presented. The "two-class" method is an earnings allocation formula that determines earnings per unit for each class of Common Unit and participating security as if all earnings for the period had been distributed. Unvested restricted unit awards that earn non-forfeitable dividend rights qualify as participating securities and, accordingly, are included in the basic computation. Our unvested restricted phantom units ("RPUs") and convertible phantom units ("CPUs") participate in dividends on an equal basis with Common Units; therefore, there is no difference in undistributed earnings allocated to each participating security. Participating securities are not allocated losses in periods where net losses occur. Our 8.25% Series A Cumulative Redeemable Perpetual Preferred Units and 8.0% Series B Perpetual Convertible Preferred Units (collectively, the "Preferred Units") rank senior to our Common Units with respect to the payment of distributions and, therefore, distributions on Preferred Units are deducted from net income when calculating net income attributable to common unitholders and participating securities. Accordingly, our calculation is prepared on a combined basis and is presented as net income (loss) per Common Unit. See Note 15 for our earnings per Common Unit calculation.

Environmental expenditures

We review, on an annual basis and when new information becomes available, our estimates of the cleanup costs of various sites. When it is probable that obligations have been incurred and where a reasonable estimate of the cost of compliance or remediation can be determined, the applicable amount is accrued. At December 31, 2015 and 2014, we had \$0.6 million and \$1.8 million undiscounted environmental liability accrued, respectively, that included cost estimates related to the maintenance of ground water monitoring wells associated with certain former well sites in Michigan that are no longer producing. In December 2015, the environmental liability decreased by \$1.2 million due to cost reductions to the estimated provision.

Accounting Standards

In April 2015, the FASB issued Accounting Standards Update ("ASU") 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. The objective of ASU 2015-03 is to simplify the presentation of debt issuance costs in financial statements by presenting such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. In August 2015, the FASB issued ASU 2015-15, *Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. This ASU amends ASU 2015-03 which had not addressed the balance sheet presentation of debt issuance costs incurred in connection with line-of-credit arrangements. Under ASU 2015-15, a company may defer debt issuance costs associated with line-of-credit arrangements and present such costs as an asset, subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings. ASU 2015-03 and ASU 2015-15 are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015 and should be applied retrospectively. Early adoption is permitted. The adoption of these standards will not have an impact on our consolidated financial statements, other than balance sheet reclassifications. Under ASU 2015-03, the unamortized debt issuance costs of approximately \$37.0 million as of December 31, 2015, associated with our outstanding Senior Notes, which were formerly presented as a component of Other Long Term Assets, will be shown as a reduction to the carrying liability amount of our Senior Notes.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*. ASU 2014-09 will supersede most of the existing revenue recognition requirements in US GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which it expects to be entitled in exchange for transferring goods or services to a customer. The new standard also requires disclosures sufficient to enable users to understand an entity's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. These new requirements become effective for annual and interim reporting periods beginning after December 15, 2017. Early adoption is permitted for annual and interim reporting periods beginning after December 15, 2016. We are assessing the impact that ASU 2014-09 will have on our consolidated financial statements.

In February 2015, the FASB issued ASU 2015-02, *Amendments to the Consolidation Analysis*, which makes changes to both the variable interest model and the voting model, affecting all reporting entities involved with limited partnerships or similar entities, particularly industries such as the oil and gas, transportation and real estate sectors. In addition to reducing the number of consolidation models from four to two, the guidance simplifies and improves current guidance by placing more emphasis on risk of loss when determining a controlling financial interest and reducing the frequency of the application of related-party guidance when determining a controlling financial interest in a VIE. The requirements of the guidance are effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period, with early adoption permitted. We do not expect the adoption of this standard to have a material effect on our consolidated financial statements and related disclosures.

In May 2015, the FASB issued ASU 2015-07, *Disclosures for Investments in Certain Entities That Calculate Net Asset Value per share (or Its Equivalent)*, which permits a reporting entity, as a practical expedient, to measure the fair value of certain investments using the net asset value per share of the investment. Currently, investments valued using the practical expedient are categorized within the fair value hierarchy on the basis of whether the investment is redeemable with the investee at net asset value on the measurement date, never redeemable with the investee at net asset value, or redeemable with the investee at net asset value at a future date. For investments that are redeemable with the investee at a future date, a reporting entity must take into account the length of time until those investments become redeemable to determine the classification within the fair value hierarchy. The update is effective for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years, with early adoption permitted. We do not expect the adoption of this standard to have a material effect on our consolidated financial statements and related disclosures.

3. Acquisitions

We account for all business combinations using the acquisition method of accounting. The initial accounting applied to our acquisitions at the time of the purchase may not be complete and adjustments to provisional accounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that existed as of the acquisition date prior to concluding on the final purchase price of an acquisition.

Our purchase price allocations are based on discounted cash flows, quoted market prices and estimates made by management, and the most significant assumptions are those related to the estimated fair values assigned to oil and natural gas properties with proved reserves. To estimate the fair values of acquired properties, estimates of oil and natural gas reserves are prepared by management in consultation with independent engineers. We apply estimated future prices to the estimated reserve quantities acquired and estimate future operating and development costs to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are discounted using a market-based weighted average cost of capital. We also periodically employ third party valuation firms to assist in the valuation of complex facilities, including pipelines, gathering lines and processing facilities.

We conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values while transaction and integration costs associated with the acquisitions are expensed as incurred.

The fair value measurements of oil and natural gas properties, other assets and ARO are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties, other assets and ARO 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 reserves, future operating and development costs, future commodity prices, estimated future cash flows and a market-based weighted average cost of capital rate. ARO assumptions include inputs such as expected economic recoveries of oil and natural gas and time to abandonment. These inputs require significant judgments and estimates by management at the time of the valuation and are subject to change.

2015 Acquisitions & Other Transactions

On March 31, 2015, we completed the acquisition of certain CO_2 producing properties located in Harding County, New Mexico (“CO_2 Assets”), for a total purchase price of $70.5 million (the “$CO_2$ Acquisition”), of which $13.7 million was paid in cash at closing and $0.6 million was paid in cash during the fourth quarter of 2015. The purchase price included $70.5 million reflected in other property, plant and equipment on the consolidated balance sheet (including $49.9 million of CO_2 supply advances and deposits paid in 2013 and 2014 and reclassified from other long-term assets to other property, plant and equipment during the six months ended June 30, 2015 and $5.1 million of intangibles reclassified from intangibles to other property, plant and equipment during the six months ended June 30, 2015) and $0.3 million of ARO reflected in asset retirement obligation on the consolidated balance sheet.

In May 2015, we completed the acquisition of additional interests in our existing fields located in Ark-La-Tex for a total preliminary purchase price of $3.0 million, which is primarily reflected in oil and natural gas properties on the consolidated balance sheet.

In August 2015, we granted a three-year term assignment of our interests in certain oil and gas leases in the Mississippian, Woodford, and Hunton formations in Kingfisher County, Oklahoma for cash consideration of $3.2 million. We reserved all existing wellbores and the production therefrom and reserved an overriding royalty interest equal to the difference between existing lease burdens appearing of record and 20%, which was later sold in December 2015 for cash consideration of $3.6 million.

In September 2015, we entered into an agreement to exchange certain of our non-contiguous acres in Martin County, Texas for non-operated producing assets in Weld County, Colorado and cash consideration of $4.8 million. We recorded a gain of $7.8 million on this transaction. The trade was for all future horizontal and vertical development rights in the oil and gas leases exchanged. We reserved all existing wellbores and the production therefrom in these Martin County, Texas acres.

2014 Acquisitions

QR Energy, LP

On November 19, 2014, we completed the merger with QRE. Under the terms of the Merger Agreement, each outstanding common unit representing a limited partner interest in QRE (a “QRE Common Unit”) and Class B Unit representing a limited partner interest in QRE (a “Class B Unit”) was converted into the right to receive 0.9856 newly issued Common Units (the “Merger Consideration”). A total of 6,748,067 Class B Units, issuable upon a change of control of QRE, were issued and treated as outstanding and along with 6,133,558 previously issued Class B Units were converted into the right to receive the Merger Consideration. Each outstanding Class C Unit (a “Class C Unit”) of QRE was converted into the right to receive cash in an amount equal to $350 million divided by the number of Class C Units outstanding immediately prior to the effective time of the QRE Merger.

We issued approximately 71.5 million Common Units as part of the Merger Consideration. In connection with the consummation of the QRE Merger, the New York Stock Exchange (the “NYSE”) was notified that each outstanding QRE Common Unit was converted into the right to receive the Merger Consideration described above, subject to the terms and conditions of the Merger Agreement. On November 21, 2014, the NYSE filed a notification of removal from listing on Form 25 with the SEC with respect to delisting the QRE Common Units.

We acquired a 59% controlling interest in ETSWDC and have consolidated ETSWDC into our consolidated financial statements. The main purpose of ETSWDC is to dispose of salt water generated as a by-product from oil produced in certain East Texas oil fields.

The final purchase price, for the 2014 QRE Merger, which was determined by management with the assistance of outside valuation consulting firms was allocated to the assets acquired and liabilities assumed as follows:

Thousands of dollars		
Cash	$	5,121
Accounts and other receivables		113,398
Current derivative instrument assets		70,362
Prepaid expenses		3,123
Oil and gas properties		2,397,967
Non-oil and gas assets		17,866
Goodwill		95,947
Long-term derivative instrument assets		72,998
Other long-term assets		50,619
Accounts payable and accrued liabilities		(157,916)
Current derivative instrument liabilities		(6,512)
Current asset retirement obligation		(2,618)
Credit facility debt		(790,000)
Senior notes at fair value		(344,129)
Long-term asset retirement obligation		(91,465)
Long-term derivative instrument liabilities		(8,877)
Other long-term liabilities		(10,277)
Non-controlling interest		(7,173)
	$	1,408,434

Acquisition-related costs for the QRE Merger were $11.8 million for the year ended December 31, 2014 and are reflected in G&A expenses on the consolidated statement of operations. For the year ended December 31, 2014, we recorded $42.1 million in revenue and $24.9 million in lease operating expenses, including production and property taxes, from the 2014 QRE Merger.

On November 19, 2014, we entered into a Transition Services Agreement ("TSA") with Quantum Resources Management, LLC ("QRM"). Under the terms of the TSA, each party agreed to provide certain land administrative, accounting, IT and marketing services to the other party. The term of the TSA commenced on November 19, 2014 and terminated on May 19, 2015.

In connection with the QRE Merger, we assumed QRE's 9.25% Senior Notes due 2020 (the "QRE Notes"), with an aggregate principal amount of $300 million, and a carrying amount of $297.0 million, net of $3.0 million of unamortized discount. We recognized the QRE Notes at their fair value at the close of the Merger of $344.1 million. Upon the closing of the QRE Merger, on November 19, 2014, QRE issued notices of redemption to the holders of the QRE Notes, specifying a redemption date of December 19, 2014 for 35% of the QRE Notes at a redemption price of 109.25% and a redemption date of December 22, 2014 for the remaining QRE Notes at a redemption price equal to 117.67% in accordance with the terms of its indenture, plus accrued and unpaid interest to the redemption dates. On November 19, 2014, QRE also placed in trust with the trustee sufficient funds to redeem all of the outstanding QRE Notes and pay accrued and unpaid interest thereon to, but not including, the applicable redemption dates. As a result, on November 19, 2014, QRE was released from its obligations under the QRE Notes and the indenture governing the QRE Notes pursuant to the satisfaction and discharge provisions described therein.

Antares Acquisition

On October 24, 2014, we completed the acquisition of certain oil and gas properties located in the Midland Basin, Texas from Antares Energy Company, a Delaware corporation, in exchange for 4.3 million Common Units and $50.0 million in cash (the "Antares Acquisition"), for a total purchase price of $122.3 million. The final purchase price was allocated to oil and natural gas assets as follows: $110.9 million to unproved properties, $13.1 million to proved properties and $1.7 million to ARO.

2013 Acquisitions

Oklahoma Panhandle Acquisitions

On July 15, 2013, we completed the acquisition of certain oil and natural gas and midstream assets located in Oklahoma, New Mexico and Texas, certain carbon dioxide ("CO_2") supply contracts, certain oil swaps and interests in certain entities from Whiting Oil and Gas Corporation ("Whiting") for approximately $845 million in cash (the "Whiting Acquisition"), including post-closing adjustments. We used borrowings under our credit facility to fund this acquisition.

The final purchase price for this acquisition was allocated to the assets acquired and liabilities assumed as follows:

Thousands of dollars		
Oil and gas properties - proved	$	700,963
Oil and gas properties - unproved		43,492
Pipeline and processing facilities		74,537
Derivative assets - current		15
Intangibles		14,739
Derivative assets - long-term		16,183
Other long-term assets		10,936
Derivative liabilities - current		(6,347)
Accrued liabilities		(1,115)
Asset retirement obligation		(8,102)
	$	845,301

Whiting novated to us derivative contracts, with a counterparty that is a participant in our current credit facility, consisting of NYMEX West Texas Intermediate ("WTI") fixed price crude oil swaps covering a total of approximately 5.4 million barrels of future production in 2013 through 2016 at a weighted average hedge price of $95.44 per Bbl, which were valued as a net asset of $9.9 million at the acquisition date. The purchase price allocation also included finite-lived intangibles valued at $14.7 million relating to two CO_2 purchase contracts that we received in the acquisition. An intangible asset was established to value the portion of the CO_2 contracts that were above market at closing in the purchase price allocation. We amortize the CO_2 contracts based on the amount of CO_2 purchases made in each period over the contracts' respective lives.We were also novated a $10.9 million long-term advance relating to future CO_2 supply contract arrangements. See Note 8 for further details on the intangibles and other long-term assets acquired.

We also completed the acquisition of additional interests in certain of the acquired assets in the Oklahoma Panhandle from other sellers for an additional $30 million in July 2013, subject to customary post-closing adjustments (together with the Whiting Acquisition, the "Oklahoma Panhandle Acquisitions"). The additional interests were allocated $17.8 million to oil and natural gas properties and $12.4 million to pipeline facilities.

We used borrowings under our credit facility to fund the Oklahoma Panhandle Acquisitions.

Acquisition-related costs for the Oklahoma Panhandle Acquisitions of $3.3 million ($3.2 million recorded in 2013), were included in G&A expenses on the consolidated statements of operations. For the year ended December 31, 2013, we recorded approximately $104.9 million in sales revenue and $29.9 million in lease operating expenses, including production and property taxes, from our Oklahoma Panhandle Acquisitions.

Permian Basin Acquisitions

On December 30, 2013, we completed acquisitions of oil and natural gas properties located in the Permian Basin in Texas from CrownRock, L.P. for approximately $282 million in cash (the "CrownRock III Acquisition"). We also completed the acquisition of additional interests in certain of the acquired assets in the Permian Basin from other sellers for an additional $20 million in December 2013 (together with the CrownRock III Acquisition, the "2013 Permian Basin Acquisitions").

The final purchase price for 2013 Permian Basin Acquisitions was allocated to the assets acquired and liabilities assumed as follows:

Thousands of dollars		
Oil and gas properties - proved	$	258,728
Oil and gas properties - unproved		44,451
Asset retirement obligation	$	(1,069)
	$	302,110

Acquisition-related costs for the 2013 Permian Basin Acquisitions were $0.6 million and $0.1 million for the years ended December 31, 2014 and 2013, respectively, and are reflected in G&A expenses on the consolidated statements of operations. For the year ended December 31, 2013, we recorded two days of sales revenue less lease operating expenses and production and property taxes of $0.2 million from our 2013 Permian Basin Acquisitions.

Pro Forma (unaudited)

The following unaudited pro forma financial information presents a summary of our combined statements of operations for the years ended December 31, 2014 and 2013 assuming: (i) the QRE Merger was completed on January 1, 2013 and (ii) the Whiting Acquisition and additional acquired assets in the Oklahoma Panhandle acquisitions and the 2013 Permian Basin Acquisitions were completed on January 1, 2012. The pro forma results reflect the results of combining our statements of operations with the results of operations from all of our 2013 and 2014 acquisitions, adjusted for (1) the assumption of ARO and accretion expense for the properties acquired, (2) depletion and depreciation expense applied to the adjusted purchase price of the properties acquired, (3) interest expense on additional borrowings necessary to finance the acquisitions, including the amortization of debt issuance costs, and (4) the effect on the denominator for calculating net income (loss) per unit of common unit issuances necessary to finance the acquisitions. The pro forma financial information is not necessarily indicative of the results of operations if these acquisitions had been effective January 1, 2014 or 2013. The Antares Acquisition in 2014 was not included in the pro forma information as Antares represented less than 0.1% of our 2014 revenue, and is considered immaterial.

	Pro Forma Year Ended December 31,	
Thousands of dollars, except per unit amounts	**2014**	**2013**
Revenues	$ 1,947,315	$ 1,280,718
Net income attributable to the partnership	541,935	102,486
Net income per common unit:		
Basic	$ 2.51	$ 0.49
Diluted	$ 2.50	$ 0.49

4. Financial Instruments and Fair Value Measurements

Our risk management programs are intended to reduce our exposure to commodity prices and interest rates and to assist with stabilizing cash flows. Routinely, we utilize derivative financial instruments to reduce this volatility. To the extent we have entered into economic hedges for a significant portion of our expected production through commodity derivative instruments and the cost for goods and services increases, our margins would be adversely affected.

Commodity Activities

Due to the historical volatility of oil and natural gas prices, we have entered into various derivative instruments to manage exposure to volatility in the market price of oil and natural gas to achieve more predictable cash flows. We use swaps, collars and options for managing risk relating to commodity prices. All contracts are settled with cash and do not require the delivery of physical volumes to satisfy settlement. While this strategy may result in us having lower revenues than we would otherwise have if we had not utilized these instruments in times of higher oil and natural gas prices, management believes that the resulting reduced volatility of prices and cash flow is beneficial. While our commodity price risk management program is intended to reduce our exposure to commodity prices and assist with stabilizing cash flow and distributions, to the extent we have hedged a significant portion of our expected production and the cost for goods and services increases, our margins would be adversely affected.

The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and natural gas prices realized in our operations. These variations often result in a lack of adequate correlation to enable these derivative instruments to qualify for cash flow hedges under FASB Accounting Standards. Accordingly, we do not currently designate any of our derivative instruments as cash flow hedges for financial accounting purposes and instead recognize changes in fair value in earnings.

We had the following oil contracts in place at December 31, 2015:

	Year			
	2016	**2017**	**2018**	**2019**
Oil Positions:				
Fixed Price Swaps - NYMEX WTI				
Volume (Bbl/d)	17,504	14,519	1,493	1,000
Average Price ($/Bbl)	$ 83.62	$ 82.81	$ 64.02	$ 56.35
Fixed Price Swaps - ICE Brent				
Volume (Bbl/d)	4,300	298	—	—
Average Price ($/Bbl)	$ 95.17	$ 97.50	$ —	$ —
Collars - NYMEX WTI				
Volume (Bbl/d)	1,500	—	—	—
Average Floor Price ($/Bbl)	$ 80.00	$ —	$ —	$ —
Average Ceiling Price ($/Bbl)	$ 102.00	$ —	$ —	$ —
Collars - ICE Brent				
Volume (Bbl/d)	500	—	—	—
Average Floor Price ($/Bbl)	$ 90.00	$ —	$ —	$ —
Average Ceiling Price ($/Bbl)	$ 101.25	$ —	$ —	$ —
Puts - NYMEX WTI				
Volume (Bbl/d)	1,000	—	—	—
Average Price ($/Bbl)	$ 90.00	$ —	$ —	$ —
Total:				
Volume (Bbl/d)	24,804	14,817	1,493	1,000
Average Price ($/Bbl)	$ 85.79	$ 83.11	$ 64.02	$ 56.35

We had the following natural gas contracts in place at December 31, 2015:

	Year			
	2016	2017	2018	2019
Gas Positions:				
Fixed Price Swaps - MichCon City-Gate				
Volume (MMBtu/d)	29,000	24,000	17,500	10,000
Average Price ($/MMBtu)	$ 3.91	$ 3.71	$ 3.10	$ 3.15
Fixed Price Swaps - Henry Hub				
Volume (MMBtu/d)	42,050	21,016	2,870	—
Average Price ($/MMBtu)	$ 4.02	$ 4.29	$ 3.74	$ —
Collars - Henry Hub				
Hedged Volume (MMBtu/d)	630	595	—	—
Average Floor Price ($/MMBtu)	$ 4.00	$ 4.00	$ —	$ —
Average Ceiling Price ($/MMBtu)	$ 5.55	$ 6.15	$ —	$ —
Puts - Henry Hub				
Volume (MMBtu/d)	11,350	10,445	—	—
Average Price ($/MMBtu)	$ 4.00	$ 4.00	$ —	$ —
Deferred Premium ($/MMBtu)	$ 0.66 (a)	$ 0.69 (b)	$ —	$ —
Total:				
Volume (MMBtu/d)	83,030	56,056	20,370	10,000
Average Price ($/MMBtu)	$ 3.98	$ 3.98	$ 3.19	$ 3.15

(a) Deferred premiums of $0.66 apply to 11,350 MMBtu/d of the 2016 volume.
(b) Deferred premiums of $0.69 apply to 10,445 MMBtu/d of the 2017 volume.

During the years ended December 31, 2015 and 2014, we did not enter into any derivative instruments that required prepaid premiums.

During the years ended December 31, 2015, 2014 and 2013, $6.7 million, $8.5 million and $4.9 million, respectively, of premiums paid in 2012 related to oil and gas derivatives settled. As of December 31, 2015, premiums paid in 2012 related to oil and natural gas derivatives to be settled in 2016 and beyond were as follows:

	Year			
Thousands of dollars	2016	2017	2018	2019
Oil	$ 7,438	$ 734	$ —	$ —
Natural gas	952	—	—	—

Interest Rate Activities

We are subject to interest rate risk associated with loans under our credit facility that bear interest based on floating rates. To fix a portion of our floating LIBOR-base debt under our credit facility, we had the following interest rate swaps in place at December 31, 2015:

	Year	
	2016	2017
Fixed Rate Swaps - LIBOR		
Notional Amount *(thousands of dollars)*	$ 710,000	$ 200,000
Average Fixed Rate	1.28%	1.23%

We do not currently designate any of our interest rate derivatives as hedges for financial accounting purposes.

Fair Value of Derivative Instruments

FASB Accounting Standards require disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedge items are accounted for, and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. The required disclosures are detailed below.

Fair value of derivative instruments not designated as hedging instruments:

Balance sheet location, thousands of dollars	Oil Commodity Derivatives	Natural Gas Commodity Derivatives	Interest Rate Derivatives	Commodity Derivatives Netting (a)	Total Financial Instruments
As of December 31, 2015					
Assets					
Current assets - derivative instruments	$ 397,748	$ 44,426	$ 222	$ (2,769)	$ 439,627
Other long-term assets - derivative instruments	202,140	27,105	216	(2,697)	226,764
Total assets	599,888	71,531	438	(5,466)	666,391
Liabilities					
Current liabilities - derivative instruments	(15)	(2,740)	(4,476)	2,769	(4,462)
Long-term liabilities - derivative instruments	—	(2,865)	(87)	2,697	(255)
Total liabilities	(15)	(5,605)	(4,563)	5,466	(4,717)
Net assets (liabilities)	$ 599,873	$ 65,926	$ (4,125)	$ —	$ 661,674
As of December 31, 2014					
Assets					
Current assets - derivative instruments	$ 350,351	$ 58,246	$ —	$ (445)	$ 408,152
Other long-term assets - derivative instruments	296,441	29,649	210	(6,740)	319,560
Total assets	646,792	87,895	210	(7,185)	727,712
Liabilities					
Current liabilities - derivative instruments	(214)	(563)	(5,126)	445	(5,458)
Long-term liabilities - derivative instruments	(1,520)	(5,220)	(2,269)	6,740	(2,269)
Total liabilities	(1,734)	(5,783)	(7,395)	7,185	(7,727)
Net assets (liabilities)	$ 645,058	$ 82,112	$ (7,185)	$ —	$ 719,985

(a) Represents counterparty netting under derivative netting agreements. The agreements allow for netting of oil and natural gas commodity derivative instruments. These contracts are reflected net on the consolidated balance sheet.

The following table presents gains and losses on derivative instruments not designated as hedging instruments:

Location of gain (loss), thousands of dollars	Oil Commodity Derivatives (a)	Natural Gas Commodity Derivatives (a)	Interest Rate Derivatives (b)	Total Financial Instruments
Year Ended December 31, 2015				
Net gain (loss)	$ 385,887	$ 52,727	$ (2,691)	$ 435,923
Year Ended December 31, 2014				
Net gain	$ 526,335	$ 40,198	$ 490	$ 567,023
Year Ended December 31, 2013				
Net gain (loss)	$ (34,259)	$ 5,077	$ —	$ (29,182)

(a) Included in gain (loss) on commodity derivative instruments, net on the consolidated statements of operations.
(b) Included in (gain) loss on interest rate swaps on the consolidated statements of operations.

Fair Value Measurements

FASB Accounting Standards define fair value, establish a framework for measuring fair value and establish required disclosures about fair value measurements. They also establish a fair value hierarchy that prioritizes the inputs to valuation techniques into three broad levels based upon how observable those inputs are. We use valuation techniques that maximize the use of observable inputs and obtain the majority of our inputs from published objective sources or third party market participants. We incorporate the impact of nonperformance risk, including credit risk, into our fair value measurements. The fair value hierarchy gives the highest priority of Level 1 to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority of Level 3 to unobservable inputs. We categorize our fair value financial instruments based upon the objectivity of the inputs and how observable those inputs are. The three levels of inputs are described further as follows:

Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date. Level 2 – Inputs other than quoted prices that are included in Level 1. Level 2 includes financial instruments that are actively traded but are valued using models or other valuation methodologies. We consider the over the counter ("OTC") commodity and interest rate swaps in our portfolio to be Level 2. Level 3 – Inputs that are not directly observable for the asset or liability and are significant to the fair value of the asset or liability. Level 3 includes financial instruments that are not actively traded and have little or no observable data for input into industry standard models. Certain OTC derivatives that trade in less liquid markets or contain limited observable model inputs are currently included in Level 3. As of December 31, 2015 and 2014, our Level 3 derivative assets and liabilities consisted entirely of OTC commodity put and call options.

Financial assets and liabilities that are categorized in Level 3 may later be reclassified to the Level 2 category at the point we are able to obtain sufficient binding market data. We had no transfers in or out of Levels 1, 2 or 3 during the years ended December 31, 2015, 2014 and 2013. Our policy is to recognize transfers between levels as of the end of the period.

Our assessment of the significance of an input to its fair value measurement requires judgment and can affect the valuation of the assets and liabilities as well as the category within which they are classified.

Derivative Instruments

We calculate the fair value of our commodity and interest rate swaps and options. We compare these fair value amounts to the fair value amounts that we receive from the counterparties on a monthly basis. Any differences are resolved and any required changes are recorded prior to the issuance of our financial statements.

The models we utilize to calculate the fair value of our Level 2 and Level 3 commodity derivative instruments are standard option pricing models. Level 2 inputs to the pricing models include the terms of our derivative contracts, commodity prices from commodity forward price curves, volatility and interest rate factors and time to expiry. Model inputs are obtained from independent third party data providers and our counterparties and are verified to published data where available (e.g., NYMEX). Additional inputs to our Level 3 derivatives include option volatilities, forward commodity prices and risk-free interest rates for present value discounting. We use the standard swap contract valuation method to value our interest rate derivatives, and inputs include LIBOR forward interest rates, one-month LIBOR rates and risk-free interest rates for present value discounting.

Assumed credit risk adjustments, based on published credit ratings and credit default swap rates, are applied to our derivative instruments.

The fair value of the commodity and interest rate derivative instruments that were novated to us in connection with the 2014 QRE Merger were estimated using a combined income and market valuation methodology based upon forward commodity prices and volatility curves. The curves were obtained from independent pricing services reflecting broker market quotes. We validated the data provided by independent pricing services by comparing such pricing against other third party pricing data.

Available-for-Sale Securities

The fair value of our available-for-sale securities are estimated using actual trade data, broker/dealer quotes, and other similar data, which are obtained from quoted market prices, independent pricing vendors, or other sources. We validate the data provided by independent pricing services to make assessments and determinations as to the ultimate valuation of its investment portfolio by comparing such pricing against other third party pricing data. We consider the inputs to the valuation of our available for sale securities to be Level 1.

Fair Value Hierarchy

The following table sets forth, by level within the hierarchy, the fair value of our financial instrument assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2015 and 2014. All fair values reflected below and on the consolidated balance sheets have been adjusted for nonperformance risk.

Thousands of dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
As of December 31, 2015				
Assets (liabilities)				
Oil derivative instruments				
Oil swaps	$ —	$ 552,552	$ —	$ 552,552
Oil collars	—	—	29,737	29,737
Oil puts	—	—	17,584	17,584
Natural gas derivative instruments				
Natural gas swaps	—	54,182	—	54,182
Natural gas collars	—	—	618	618
Natural gas puts	—	—	11,126	11,126
Interest rate swaps				
Interest rate swaps	—	(4,125)	—	(4,125)
Available-for-sale securities				
Equities	2,524	—	—	2,524
Mutual Funds	11,190	—	—	11,190
Exchange traded funds	4,977	—	—	4,977
Net assets	$ 18,691	$ 602,609	$ 59,065	$ 680,365
As of December 31, 2014				
Assets (liabilities)				
Oil derivative instruments				
Oil swaps	$ —	$ 583,648	$ —	$ 583,648
Oil collars	—	—	44,405	44,405
Oil puts	—	—	17,005	17,005
Natural gas derivative instruments				
Natural gas swaps	—	62,220	—	62,220
Natural gas collars	—	—	13,256	13,256
Natural gas puts	—	—	6,636	6,636
Interest rate swaps				
Interest rate swaps	—	(7,185)	—	(7,185)
Available-for-sale securities				
Equities	4,138	—	—	4,138
Mutual Funds	10,577	—	—	10,577
Exchange traded funds	4,630	—	—	4,630
Net assets	$ 19,345	$ 638,683	$ 81,302	$ 739,330

The following table sets forth a reconciliation of changes in fair value of our derivative instruments classified as Level 3:

	Year End December 31,					
	2015		2014		2013	
Thousands of dollars	Oil	Natural Gas	Oil	Natural Gas	Oil	Natural Gas
Assets (a):						
Beginning balance	$ 61,410	$ 19,892	$ 8,957	$ 1,848	$ 15,169	$ 1,672
Derivative instrument settlements (b)	44,647	16,815	4,094	815	(125)	(892)
Gain (loss) (b)(c)	(58,736)	(24,963)	37,189	5,357	(6,087)	1,068
Purchases (b)(d)	—	—	11,170	11,872	—	—
Ending balance	$ 47,321	$ 11,744	$ 61,410	$ 19,892	$ 8,957	$ 1,848

(a) We had no fair value changes for our derivative instruments classified as Level 3 related to sales or issuances.

(b) Included in gain (loss) on commodity derivative instruments, net on the consolidated statements of operations.
(c) Represents gain (loss) on mark-to-market of derivative instruments.
(d) 2014 purchases related to derivative instruments novated to us in connection with the QRE Merger.

For Level 3 derivatives measured at fair value on a recurring basis as of December 31, 2015, the significant unobservable inputs used in the fair value measurements were as follows:

Thousands of dollars	Fair Value at December 31, 2015	Valuation Technique	Unobservable Input	Range
Oil options	$ 47,321	Option Pricing Model	Oil forward commodity prices	$37.04/Bbl - $47.79/Bbl
			Oil volatility	32.24% - 44.95%
			Own credit risk	5%
Natural gas options	11,744	Option Pricing Model	Gas forward commodity prices	$2.34/MMBtu - $2.99/MMBtu
			Gas volatility	23.44% - 73.05%
			Own credit risk	5%
Total	$ 59,065			

For Level 3 derivatives measured at fair value on a recurring basis as of December 31, 2014, the significant unobservable inputs used in the fair value measurements were as follows:

Thousands of dollars	Fair Value at December 31, 2014	Valuation Technique	Unobservable Input	Range
Oil options	$ 61,410	Option pricing model	Oil forward commodity prices	$53.27/Bbl - $71.66/Bbl
			Oil volatility	29.21% - 46.16%
			Own credit risk	5%
Natural gas options	19,892	Option pricing model	Gas forward commodity prices	$2.88/MMBtu - $3.99/MMBtu
			Gas volatility	18.59% - 63.51%
			Own credit risk	5%
Total	$ 81,302			

Credit and Counterparty Risk

Financial instruments, which potentially subject us to concentrations of credit risk consist principally of derivatives and accounts receivable. Our derivatives expose us to credit risk from counterparties. As of December 31, 2015, our derivative counterparties were Bank of Montreal, Barclays Bank PLC, BNP Paribas, Canadian Imperial Bank of Commerce, Citibank, N.A., Citizens Bank, National Association, Comerica Bank, Credit Agricole Corporate and Investment Bank, Credit Suisse Energy LLC, Credit Suisse International, ING Capital Markets LLC, JP Morgan Chase Bank N.A., Merrill Lynch Commodities, Inc., Morgan Stanley Capital Group Inc., Royal Bank of Canada, The Bank of Nova Scotia, The Toronto-Dominion Bank, Union Bank N.A. and Wells Fargo Bank, N.A. Our counterparties are all lenders under our Credit Agreement. Our credit agreement is secured by our oil, NGL and natural gas reserves, so we are not required to post any collateral, and we conversely do not receive collateral from our counterparties. On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits and monitor the appropriateness of these limits on an ongoing basis. We periodically obtain credit default swap information on our counterparties. Although we currently do not believe we have a specific counterparty risk with any party, our loss could be substantial if any of these parties were to fail to perform in accordance with the terms of the contract. This risk is managed by diversifying our derivatives portfolio. As of December 31, 2015, each of these financial institutions had an investment grade credit rating. As of December 31, 2015, our largest derivative asset balances were with Wells Fargo Bank, N.A., Barclays Bank PLC, Credit Suisse Energy LLC and Morgan Stanley Capital Group Inc., which accounted for approximately 15%, 13%, 11% and 11% of our derivative asset balances, respectively.

5. Related Party Transactions

Breitburn Management operates our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. All of our employees, including our executives, are employees of Breitburn Management.

Breitburn Management also provides administrative services to PCEC, our Predecessor, under an administrative services agreement, in exchange for a monthly fee for indirect expenses and reimbursement for all direct expenses, including incentive compensation plan costs and direct payroll and administrative costs related to PCEC properties and operations. For each of the years ended December 31, 2015 and 2014, the monthly fee paid by PCEC for indirect expenses was $700,000. On May 1, 2015, Breitburn Management and PCEC entered into Amendment No. 5 to the Administrative Services Agreement ("ASA"), extending the term of the ASA to December 31, 2016; provided, however, in the event PCEC has not received certain permits by December 31, 2015, PCEC may terminate the ASA effective as of June 30, 2016 by giving prior written notice to Breitburn Management of its intention to terminate the ASA by December 31, 2015. The deadline to provide notice of termination was extended on December 22, 2015 to January 31, 2016 and again on January 29, 2016 to February 8, 2016. On February 5, 2016, PCEC provided written notice to Breitburn Management of its intention to terminate the ASA effective as of June 30, 2016.

At December 31, 2015 and 2014, we had net current receivables of $1.7 million and $2.4 million, respectively, due from PCEC related to the applicable administrative services agreement, employee related costs and oil and gas sales made by PCEC on our behalf from certain properties. For the years ended December 31, 2015, 2014, and 2013, the monthly charges to PCEC for indirect expenses totaled $8.4 million, $8.4 million and $8.4 million, respectively, and charges for direct expenses including direct payroll and other direct costs totaled $9.6 million, $10.9 million and $10.6 million, respectively.

Effective on April 8, 2015, the closing date of private offerings of senior secured second lien notes and perpetual convertible preferred units (see Note 9 and Note 15, respectively), Kurt A. Talbot, then Vice Chairman and Co-Head of the Investment Committee of EIG Global Energy Partners ("EIG"), was appointed to the board of directors of Breitburn GP LLC, our General Partner. We paid EIG Management Company, LLC, an affiliate of EIG, a transaction fee of $13 million with respect to the purchase of the senior secured second lien notes and a transaction fee of $7 million with respect to the purchase of the perpetual convertible preferred units.

6. Impairments

Long-Lived Assets

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles and the outlook for market supply and demand conditions for oil and natural gas. For purposes of performing an impairment test, the undiscounted future cash flows are based on total proved and risk-adjusted probable and possible reserves and are forecast using five-year NYMEX forward strip prices at the end of the period and escalated along with expenses and capital starting year six and thereafter at 2% per year. Production and development cost estimates (e.g. operating expenses and development capital) are conformed where applicable to reflect the commodity price strip used. For impairment charges, the associated property's expected future net cash flows were discounted using a market-based long-term weighted average cost of capital rate that currently approximates 10%. Additional inputs include oil and natural gas reserves, future operating and development costs and future commodity prices. We consider the inputs for our impairment calculations to be Level 3 inputs. The impairment reviews and calculations are based on assumptions that are consistent with our business plans.

During the year ended December 31, 2015, we recorded non-cash impairments related to our oil, NGL and natural gas properties of $2.4 billion, including $740.6 million in the Midwest, $512.8 million in Ark-La-Tex, $443.8 million in the Southeast, $256.5 million in the Permian Basin, $213.0 million in California, $147.9 million in the Rockies, and $63.0 million in Mid-Continent. The impairments were primarily due to the impact that the sustained drop in commodity strip prices had on our projected future net revenues.

During the year ended December 31, 2014, we recorded non-cash impairments related to our oil, NGL and natural gas properties of $149.0 million, including $124.8 million in the Southeast, $11.2 million in the Rockies, $8.5 million in the Midwest, $2.3 million in the Permian Basin and $2.2 million in Mid-Continent. The impairments in the Southeast were due to reserve adjustments primarily related to lower crude oil prices and well performance. The Rockies impairments were due to reserve adjustments related to a combination of lower oil prices, well performance and higher expense projections. The Midwest impairments related to lower commodity prices and the write-off of investments associated with expiring leases that we elected not to renew. The Permian Basin and Mid-Continent property impairments related to lower commodity prices.

During the year ended December 31, 2013, we recorded non-cash impairment charges of approximately $54.4 million, including $28.3 million of impairments to our Michigan non-Antrim oil and gas properties due to negative reserve adjustments due to lower performance and a decrease in expected future commodity prices, and $25.3 million of impairments to an oil property in our Bighorn Basin in Northern Wyoming due to a negative reserve adjustment due to lower performance and a decrease in expected future oil prices. Decreased drilling activity in Michigan was also a factor as we continued to allocate our capital expenditures more towards liquids-rich areas.

Given the number of assumptions involved in the estimates, an estimate as to the sensitivity to earnings for these periods if other assumptions had been used in impairment reviews and calculations is not practicable. Favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused additional impairment charges to those assets that were impaired and/or additional assets that were not impaired.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is not amortized, but is tested for impairment annually or whenever indicators of impairment exist and then charged to impairment expense. The analysis of the potential impairment of goodwill is a two-step process. Step one of the impairment test consists of comparing the fair value of the reporting unit with the aggregate carrying value, including goodwill. If the carrying value of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of goodwill impairment.

If the fair value of the reporting unit is less than its carrying value, step two of the goodwill impairment test is performed. Step two consists of comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. Determining the implied fair value of goodwill requires the valuation of a reporting unit's identifiable tangible and intangible assets and liabilities as if the reporting unit had been acquired in a business combination on the testing date. The fair value of the tangible and intangible assets and liabilities is based upon various assumptions including a discounted cash flow approach to value our oil and gas reserves (the "Income Approach"). The Income Approach valuation method requires projections of revenue and operating costs over a multi-year period. The valuation of assets and liabilities in step two is performed only for purposes of assessing goodwill for impairment.

As of March 31, 2015, we had $95.9 million of goodwill related to the 2014 QRE Merger (see Note 3). Due to a decrease in the price of our Common Units during the second quarter of 2015, we performed a qualitative goodwill impairment assessment. In the first step of the goodwill impairment test, we determined that the fair value of our goodwill was less than the carrying amount, primarily due to the decrease in the price of our Common Units. Therefore, we performed the second step of the goodwill impairment test, which led us to conclude that there was no remaining implied fair value attributable to goodwill. Based on this assessment, we recorded a non-cash goodwill impairment charge of $95.9 million during the second quarter of 2015.

7. Investments

Our available-for-sale securities comprise primarily of equity, mutual funds and exchange traded funds. They consist of investments not classified as trading securities or as held-to-maturity. Our investments are included in other long-term assets on our consolidated balance sheets.

As of December 31, 2015, we had the following available-for-sale investments outstanding:

Thousands of dollars	**Cost Basis**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
Available-for-sale securities:				
Equities	$ 2,591	$ 141	$ (208)	$ 2,524
Mutual funds	13,276	1,737	(3,823)	11,190
Exchange traded funds	3,721	1,494	(238)	4,977
Total available-for-sale securities	$ 19,588	$ 3,372	$ (4,269)	$ 18,691

As of December 31, 2014, we had the following available-for-sale investments outstanding:

Thousands of dollars	**Cost Basis**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
Available-for-sale securities:				
Equities	$ 4,203	$ 92	$ (157)	$ 4,138
Mutual funds	10,623	20	(66)	10,577
Exchange traded funds	4,808	27	(205)	4,630
Total available-for-sale securities	$ 19,634	$ 139	$ (428)	$ 19,345

During the years ended December 31, 2015 and 2014, we received $3.9 million and $0.5 million, respectively, in proceeds from the sale of available-for-sale securities, and recognized a realized loss of $0.1 million and a realized loss of less than $0.1 million, respectively, reflected in other expense (income), net on the consolidated statements of operations.

We evaluate securities for other than temporary impairment on a quarterly basis and more frequently when economic or market concerns warrant such an evaluation. The unrealized losses in the table above have been outstanding for less than two months. We have evaluated the unrealized losses and have determined that these losses do not represent an other than temporary impairment.

Fair value of our available for sale securities are estimated using actual trade data, broker/dealer quotes, and other similar data, which are obtained from quoted market prices, independent pricing vendors, or other sources. We validate the data provided by independent pricing services to make assessments and determinations as to the ultimate valuation of its investment portfolio by comparing such pricing against other third party pricing data.

8. Other Long-Term Assets

As of December 31, 2015 and 2014, our other long-term assets were $117.9 million and $165.4 million, respectively, consisting of the following:

	As of December 31,	
Thousands of dollars	**2015**	**2014**
Debt issuance costs (Note 9)	59,167	52,787
Available-for-sale securities (Note 7)	18,691	19,345
Deposit for Jay Field net profit interest obligation	18,263	18,263
Property reclamation deposit	10,736	10,735
CO_2 supply advances and deposits (Note 3)	—	50,792
Intangible assets	365	8,336
Other	10,650	5,120
Total	117,872	165,378

NPI Obligation

We have a net profit interest ("NPI") related to the Jay Field. Under the arrangement, the NPI is payable after: (i) funds are withheld, to the extent allowable each month under the arrangement, to pay for the NPI holder's share of future development costs and abandonment obligations, and (ii) we are reimbursed for the NPI holder's share of excess historical productions costs. Once the NPI holder's share of the excess historical costs is reimbursed, the NPI will be payable monthly to the extent the NPI for that month exceeds the amount withheld for that month for future development costs and abandonment obligations. The NPI holder's share of excess historical production costs amounted to $9.8 million and $2.3 million at December 31, 2015 and 2014, respectively. In addition, we will retain the NPI holder's shares of future development costs and abandonment obligations, subject to future production, production costs, and capital spending level, which will be paid using the funds withheld. The NPI holder's share along with our share of the abandonment costs as of December 31, 2015 are reflected in asset retirement obligation on the consolidated balance sheet. Under the arrangement, we have the option to deposit into a separate account the funds withheld from the NPI holder for their portion of the future development costs and abandonment obligations. The funds totaled $18.3 million as of December 31, 2015 and 2014, which is reflected in other long-term assets on the consolidated balance sheet.

Property Reclamation Deposit

We have a property reclamation deposit of $10.7 million in an escrow account as security for future abandonment and remediation obligations for the Jay Field. As of December 31, 2015 and 2014, $10.7 million was recorded in other long-term assets related to the deposit. We are required to maintain the escrow account in effect for three years after all abandonment and remediation obligations have been completed. The funds in the escrow account are not to be returned to us until the later of three years after satisfaction of all abandonment obligations or December 31, 2026. At certain dates subsequent to closing, we have the right to request a refund of a portion or all of the property reclamation deposit. Granting of the request is at the seller's sole discretion. In addition to the cash deposit, we are required to provide letters of credit. At December 31, 2015 and 2014, we had $23.4 million in letters of credit related to the property reclamation deposit.

Intangible Assets

In connection with the 2013 Whiting Acquisition (see Note 3), we acquired two CO_2 purchase contracts that were priced below market, which were valued at $14.7 million at the acquisition date. These contracts were recorded as finite-lived intangibles. We amortize these contracts based on the amount of CO_2 purchases made in each period over the contracts' respective lives. For the years ended December 31, 2015, 2014 and 2013, we recorded $2.2 million, $3.9 million and $3.6 million, respectively, in amortization expense related to these contracts. In connection with the CO_2 Acquisition in 2015, we reclassified $5.1 million of the remaining CO_2 purchase contract from intangibles to other property, plant and equipment.

9. Long-Term Debt

Our long-term debt is detailed in the following table:

	As of December 31,	
Thousands of dollars	2015	2014
Credit facility	$ 1,229,000	$ 2,194,500
Promissory note	2,938	1,100
9.25% Senior Secured Notes due 2020	650,000	—
8.625% Senior Unsecured Notes due 2020	305,000	305,000
7.875% Senior Unsecured Notes due 2022	850,000	850,000
Net (discount) premium on Senior Notes	(15,781)	1,560
Total debt	3,021,157	3,352,160
Less: Current portion of long-term debt	(154,000)	(105,000)
Total long-term debt	$ 2,867,157	$ 3,247,160

Credit Facility

BOLP, as borrower, and we and our wholly-owned subsidiaries, as guarantors, have a $5.0 billion revolving credit facility with Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and Issuing Lender, and a syndicate of banks with a maturity date of November 19, 2019. We entered into the Third Amended and Restated Credit Agreement on November 19, 2014, in connection with the 2014 QRE Merger.

On April 8, 2015, in connection with financing and related party transactions with EIG Global Energy Partners, we entered into the First Amendment (the "First Amendment") to the Credit Agreement (as amended, the "Credit Agreement"). Among other changes, the First Amendment: (i) established a borrowing base of $1.8 billion until the April 1, 2016 scheduled redetermination date subject, starting with the October 1, 2015 scheduled redetermination date, to our having liquidity (inclusive of borrowing base availability) of 10% of the borrowing base; (ii) permitted $650 million of second lien indebtedness; (iii) increased the base rate and LIBOR margins by 0.25%; (iv) added a requirement that we have liquidity (inclusive of borrowing base availability) of 10% of the borrowing base after giving effect to any distribution on our Common Units or voluntary prepayment of second lien indebtedness; and (v) added a requirement that we have liquidity (inclusive of borrowing base availability) of 5% of the borrowing base after giving effect to any distribution on our Series B Preferred Units (as defined below).

Our credit facility limits the amounts we can borrow to a borrowing base amount determined by the lenders at their sole discretion based on their valuation of our proved reserves and their internal criteria. The borrowing base is redetermined semi-annually. Currently, our borrowing base for our credit facility is $1.8 billion, and the aggregate commitment of all lenders is $1.8 billion. Our next borrowing base redetermination is scheduled for April 2016.

The Credit Agreement requires us to maintain an Interest Coverage Ratio (defined as EBITDAX divided by Consolidated Interest Expense) and a Current Ratio (defined as current assets divided by current liabilities) for the four quarters ending on the last day of each quarter beginning with the fourth quarter of 2014 of no less than 2.50 to 1.00 and 1.00 to 1.00, respectively. EBITDAX is not a defined US GAAP measure. The Credit Agreement defines EBITDAX as consolidated net income plus exploration expense, interest expense, income tax provision, DD&A, unrealized loss or gain on derivative instruments, non-cash charges, including non-cash unit-based compensation expense, loss or gain on sale of assets (excluding gain or loss on monetization of derivative instruments for the following twelve months), cumulative effect of changes in accounting principles, cash distributions received from our unrestricted entities (as defined in the Credit Agreement) and excluding income from our unrestricted entities. If any acquisition or disposition was consummated during an applicable quarter, all calculations of EBITDAX shall be determined on a pro forma basis.

As of December 31, 2015 and 2014, we had $1.2 billion and $2.2 billion, respectively, in indebtedness outstanding under the credit facility. At December 31, 2015, the 1-month LIBOR interest rate plus an applicable spread was 2.6084% on the 1-month LIBOR portion of $1.2 billion. During the year ended December 31, 2015, we recognized a write-off of $10.6 million of debt issuance costs, included in interest expense, net of capitalized interest on the consolidated statements of operations, relating to the reduction of our credit facility borrowing base from $2.5 billion to $1.8 billion in connection with the EIG financing. At December 31, 2015 and 2014, we had $22.1 million and $33.5 million, respectively, of unamortized debt issuance costs related to our credit facility.

Borrowings under the Credit Agreement are secured by first-priority liens on and security interests in substantially all of our and certain of our subsidiaries' assets, representing not less than 80% of the total value of our oil and gas properties.

The Credit Agreement contains customary covenants, including restrictions on our ability to: incur additional indebtedness; make certain investments, loans or advances; make distributions to our unitholders or repurchase units (including the restriction on our ability to make distributions unless, after giving effect to such distribution, we remain in compliance with all terms and conditions of our credit facility); make dispositions or enter into sales and leasebacks; or enter into a merger or sale of our property or assets, including the sale or transfer of interests in our subsidiaries. As of December 31, 2015 and 2014, we were in compliance with our credit facility's covenants.

The Credit Agreement also permits us to terminate derivative contracts without obtaining the consent of the lenders in the facility, provided that the net effect of such termination plus the aggregate value of all dispositions of oil and gas properties made during such period, together, does not exceed 5% of the borrowing base, and the borrowing base will be automatically reduced by an amount equal to the net effect of the termination.

The events that constitute an Event of Default (as defined in the Credit Agreement) include: payment defaults; misrepresentations; breaches of covenants; cross-default and cross-acceleration to certain other indebtedness; adverse judgments against us in excess of a specified amount; changes in management or control; loss of permits; certain insolvency events; and assertion of certain environmental claims.

The carrying value of our credit facility as of December 31, 2015 approximated fair value. We consider the fair value of our credit facility to be Level 2, as it is based on the current active market 1-month LIBOR.

Promissory Note

ETSWDC, as borrower, has a secured $6.0 million Promissory Note with Texas Capital Bank, NA, with a maturity date of November 13, 2019. As of December 31, 2015 and 2014, ETSWDC had $2.9 million and $1.1 million, respectively, outstanding under the Promissory Note. At December 31, 2015, the 1-month LIBOR interest rate plus an applicable spread was 2.3584%.

Senior Secured Notes

On April 8, 2015, we issued $650 million of 9.25% Senior Secured Second Lien Notes due 2020 ("Senior Secured Notes") in a private offering to EIG Redwood Debt Aggregator, LP and certain other purchasers at a purchase price of 97% of the principal amount. We received approximately $606.9 million from this offering, net of fees and estimated expenses, which we primarily used to repay borrowings under our credit facility. Interest on our Senior Secured Notes is payable quarterly in March, June, September and December. As of December 31, 2015, our Senior Secured Notes had a carrying value of $632.7 million, net of unamortized discount of $17.3 million.

As of December 31, 2015, the fair value of our Senior Secured Notes was estimated to be approximately $518 million, based on quoted yields for similarly rated debt instruments currently available in the market, and we consider the valuation of our Senior Secured Notes to be Level 3.

At December 31, 2015, we had $20.6 million, of unamortized debt issuance costs related to our Senior Secured Notes.

Senior Unsecured Notes

As of December 31, 2015, we had $305 million in aggregate principal amount of 8.625% Senior Notes due 2020 (the "2020 Senior Notes"). The 2020 Senior Notes were offered at a discount price of 98.358%, or $300 million. The $5 million discount is being amortized over the life of the 2020 Senior Notes. In addition, as of December 31, 2015, we had $850 million in aggregate principal amount of 7.875% Senior Notes due 2022 (the "2022 Senior Notes"). Interest on the 2020 Senior Notes and the 2022 Senior Notes is payable twice a year in April and October.

As of December 31, 2015 and 2014, the 2020 Senior Notes had a carrying value of $302.1 million and $302.1 million, respectively, net of unamortized discount of $2.9 million and $2.9 million, respectively.

As of December 31, 2015 and 2014, the fair value of the 2020 Senior Notes was estimated to be $59 million and $262 million, respectively. We consider the inputs to the valuation of our 2020 Senior Notes to be Level 2, as fair value was estimated based on prices quoted from third party financial institutions.

In connection with the 2020 Senior Notes, we incurred financing fees and expenses of approximately $8.8 million, which are being amortized over the life of the 2020 Senior Notes. At December 31, 2015 and 2014, unamortized debt issuance costs related to our 2020 Senior Notes were $4.2 million and $5.1 million, respectively.

As of December 31, 2015 and 2014, the 2022 Senior Notes had a carrying value of $854.5 million and $854.5 million, respectively, net of unamortized premium of $4.5 million and $4.5 million, respectively. Interest on the 2022 Senior Notes is payable twice a year in April and October. As of December 31, 2015 and 2014, the fair value of the 2022 Senior Notes was estimated to be $157 million and $661 million, respectively. We consider the inputs to the valuation of our 2022 Senior Notes to be Level 2, as fair value was estimated based on prices quoted from third party financial institutions.

At December 31, 2015 and 2014, unamortized debt issuance costs related to our 2022 Senior Notes were $12.2 million and $14.1 million, respectively.

The indentures governing both our 2020 Senior Notes and 2022 Senior Notes contain covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) sell assets including equity interests in our subsidiaries; (ii) pay distributions on, redeem or repurchase our units or redeem or repurchase our subordinated debt; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in transactions with affiliates; (ix) create unrestricted subsidiaries; or (x) engage in certain business activities. If the 2020 Senior Notes and 2022 Senior Notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the indentures) has occurred and is continuing, many of these covenants will terminate.

As of December 31, 2015 and December 31, 2014, we were in compliance with the covenants on our 2020 Senior Notes and 2022 Senior Notes.

Interest Expense

Our interest expense is detailed in the following table:

Thousands of dollars	Year Ended December 31, 2015	2014	2013
Credit facility (including commitment fees)	$ 41,254	$ 23,788	$ 15,698
Senior Secured Notes	43,758	—	—
Senior Unsecured Notes	93,244	95,662	65,068
Amortization of discount/premium and deferred issuance costs (a)	24,926	7,836	6,429
Capitalized interest	(155)	(326)	(128)
Total	$ 203,027	$ 126,960	$ 87,067
Cash paid for interest	$ 181,873	$ 119,488	$ 74,078

(a) The year ended December 31, 2015 included a write-off of $10.6 million of debt issuance costs related to the reduction of our credit facility borrowing base.

10. Condensed Consolidating Financial Statements

We and Breitburn Finance (and BOLP, with respect to the Senior Secured Notes) as co-issuers, and certain of our subsidiaries as guarantors, issued the Senior Secured Notes and the Senior Unsecured Notes (collectively, the "Senior Notes"). All but two of our subsidiaries have guaranteed our Senior Notes. Our only non-guarantor subsidiaries, Breitburn Utica and ETSWDC, are minor subsidiaries.

In accordance with Rule 3-10 of Regulation S-X, we are not presenting condensed consolidating financial statements as we have no independent assets or operations; Breitburn Finance, the subsidiary co-issuer, which does not guarantee the Senior Notes, is a wholly-owned finance subsidiary; all of our material subsidiaries are wholly-owned, have guaranteed the Senior Notes, and all of the guarantees are full, unconditional, joint and several.

Each guarantee of the Senior Notes is subject to release in the following customary circumstances:

(1) a disposition of all or substantially all the assets of the guarantor subsidiary (including by way or merger or consolidation), to a third person, provided the disposition complies with the applicable indenture,
(2) a disposition of the capital stock of the guarantor subsidiary to a third person, if the disposition complies with the applicable indenture and as a result the guarantor subsidiary ceases to be our subsidiary,
(3) the designation by us of the guarantor subsidiary as an Unrestricted Subsidiary in accordance with the applicable indenture,
(4) legal or covenant defeasance of such series of Senior Notes or satisfaction and discharge of the related indenture,
(5) the liquidation or dissolution of the guarantor subsidiary, provided no default under the applicable indenture exists, or
(6) the guarantor subsidiary ceases both (a) to guarantee any other indebtedness of ours or any other guarantor subsidiary and (b) to be an obligor under any bank credit facility.

11. Income Taxes

We, and all of our subsidiaries, with the exception of Phoenix Production Company ("Phoenix"), Breitburn Management, ETSWDC, Alamitos Company, Breitburn Finance and QRE Finance Corporation ("QRE Finance"), are partnerships or limited liability companies treated as partnerships for federal and state income tax purposes. Essentially all of our taxable income or loss, which may differ considerably from the net income or loss reported for financial reporting purposes, is passed through to the federal income tax returns of our partners. As such, we have not recorded any federal income tax expense for those pass-through entities.

The consolidated income tax expense (benefit) attributable to our tax-paying entities consisted of the following:

	Year Ended December 31,		
Thousands of dollars	**2015**	**2014**	**2013**
Federal income tax expense (benefit)			
Current	$ 626	$ 212	$ 472
Deferred (a)	784	(173)	262
Current state income tax expense (benefit) (b)	117	(112)	171
Total	$ 1,527	$ (73)	$ 905

(a) Related to Phoenix and Breitburn Management, our wholly-owned subsidiaries, and ETSWDC, a subsidiary we have a controlling interest in.
(b) Primarily in California and Texas.

At December 31, 2015 and 2014, a net deferred federal income tax liability of $3.4 million and $2.0 million, respectively, was reported on our consolidated balance sheet for Phoenix, Breitburn Management and ETSWDC, including a liability reflected in deferred income taxes of $3.8 million and $2.6 million, respectively, and deferred tax asset of $0.4 million and $0.6 million, respectively, included in other long-term assets on the consolidated balance sheet. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting and the amount used for income tax purposes. Significant components of our net deferred tax liabilities are presented in the following table:

	December 31,	
Thousands of dollars	**2015**	**2014**
Deferred tax assets:		
Asset retirement obligation	$ 2,296	$ 2,120
Operating loss carryforwards	3,714	2,341
Unused minimum tax credit	—	440
Compensation accruals	1,558	1,315
Pension costs	1,724	2,461
Post-retirement costs	823	952
Other	309	103
Valuation allowance	(6,542)	(4,243)
Deferred tax liabilities:		
Depreciation, depletion and intangible drilling costs	(6,505)	(6,455)
Unrealized hedge gain	(825)	(1,069)
Net deferred tax liability	$ (3,448)	$ (2,035)

At December 31, 2015, we had unused federal net operating loss carryforwards totaling $10.9 million. The net operating loss carryforwards expire between 2026 and 2035. We have not fully recognized the deferred tax assets for certain items in advance of their deductibility for income tax purposes due to uncertainty of realization. The benefit of these items will be recognized in future years to the extent that such deductions are used to reduce taxable income.

Approximately $5.9 million of the net operating loss carryforwards acquired in connection with the 2014 QRE Merger, relating to ETSWDC, are subject to an annual utilization limitation of approximately $0.6 million pursuant to the “change in ownership” provisions under Section 382 of the Internal Revenue Code of 1986, as amended.

On a consolidated basis, cash paid for federal and state income taxes totaled $0.5 million, $0.2 million and $0.5 million during the years ended December 31, 2015, 2014 and 2013, respectively.

FASB Accounting Standards clarify the accounting for uncertainty in income taxes recognized in a company's financial statements. A company can only recognize the tax position in the financial statements if the position is more-likely-than-not to be upheld on audit based only on the technical merits of the tax position. FASB Accounting Standards also provide guidance on thresholds, measurement, derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition that is intended to provide better financial statement comparability among different companies.

We performed analysis as of December 31, 2015, 2014 and 2013 and concluded that there were no uncertain tax positions requiring recognition in our financial statements.

12. Asset Retirement Obligation

ARO is based on our net ownership in wells and facilities and our estimate of the costs to abandon and remediate those wells and facilities together with our estimate of the future timing of the costs to be incurred. Payments to settle ARO occur over the operating lives of the assets, estimated to range from less than one year to 50 years. Estimated cash flows have been discounted at our credit-adjusted risk-free rate that approximated 14% and 7% for the years ended December 31, 2015 and 2014, respectively, and adjusted for inflation using a rate of 2%. Our credit-adjusted risk-free rate is calculated based on our cost of borrowing adjusted for the effect of our credit standing and specific industry and business risk. We consider the inputs to our ARO valuation to be Level 3 as fair value is determined using discounted cash flow methodologies based on standardized inputs that are not readily observable in public markets.

Changes in ARO for the years ended December 31, 2015 and 2014, are presented in the following table:

	Year Ended December 31,	
Thousands of dollars	**2015**	**2014**
Carrying amount, beginning of period	$ 238,411	$ 123,769
Liabilities added from acquisitions	796	95,800
Liabilities incurred from drilling	2,268	4,020
Liabilities settled	(7,744)	(1,708)
Liabilities related to divested properties	(261)	—
Revision of estimates	3,954	6,770
Accretion expense	16,954	9,760
Carrying amount, end of period	254,378	238,411
Less: Current portion of ARO	(2,341)	(4,948)
Non-current portion of ARO	$ 252,037	$ 233,463

13. Pensions and Postretirement Benefits

ETSWDC sponsors a non-contributory defined benefit pension plan and a contributory other post-retirement benefit plan (collectively, the "Plans") covering substantially all ETSWDC employees who were employed prior to March 31, 2008. Subsequent to March 31, 2008, the Plans were closed to new employees. The tables below set forth the benefit obligation, fair value of plan assets, and the funded status of the Plans; amounts recognized in our financial statements; and the principal weighted average assumptions used.

Obligation and Funded Status

The Plans had accumulated benefit obligations in excess of plan assets at December 31, 2015 and 2014 as follows:

Thousands of dollars	December 31, 2015 Pension Benefits	December 31, 2015 Postretirement Benefits	December 31, 2014 Pension Benefits	December 31, 2014 Postretirement Benefits
Projected benefit obligation	$ 25,320	$ 3,971	27,829	4,240
Accumulated benefit obligation	24,424	3,971	26,872	4,240
Fair value of plan assets	20,022	1,468	21,219	1,527

The change in the combined projected benefit obligation of the Plans and the change in the assets at fair value are as follows:

Thousands of dollars	Year Ended December 31, 2015 Pension Benefits	Year Ended December 31, 2015 Postretirement Benefits	Year Ended December 31, 2014 Pension Benefits	Year Ended December 31, 2014 Postretirement Benefits
Change in Benefit Obligation				
Benefit obligation at beginning of year	$ 27,829	$ 4,240	$ —	$ —
2014 Acquisition of ETSWDC	—	—	27,300	4,144
Service cost	271	34	33	4
Interest cost	1,014	155	120	18
Plan participant contributions	—	28	—	2
Actuarial (gain) loss	(2,360)	(333)	496	85
Benefits paid	(1,434)	(153)	(120)	(13)
Benefit obligation at end of year	25,320	3,971	27,829	4,240
Change in Plan Assets				
Fair value of plan assets at beginning of year	21,219	1,527	—	—
2014 Acquisition of ETSWDC	—	—	21,319	1,518
Actual return on plan assets	(163)	(63)	20	9
Employer contributions	400	129	—	11
Plan participant contributions	—	28	—	2
Benefits paid	(1,434)	(153)	(120)	(13)
Fair value of plan assets at end of year	20,022	1,468	21,219	1,527
Underfunded status at end of year	$ (5,298)	$ (2,503)	(6,610)	(2,713)

Amounts Recognized on the Consolidated Balance Sheet

Amounts recognized on the consolidated balance sheet at December 31, 2015 and 2014 are as follows:

Thousands of dollars	December 31, 2015 Pension Benefits	December 31, 2015 Postretirement Benefits	December 31, 2014 Pension Benefits	December 31, 2014 Postretirement Benefits
Long-term liabilities	5,298	2,503	6,610	2,713

Components of Net Periodic Benefit Cost and Other Comprehensive Income

Net periodic benefit costs recognized on the consolidated statements of operations for the years ended December 31, 2015 and 2014 consist of the following:

	Year Ended December 31, 2015		Year Ended December 31, 2014	
Thousands of dollars	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Service cost	$ 271	$ 34	$ 33	$ 4
Interest cost	1,014	155	120	18
Expected return on plan assets	(1,342)	(99)	(152)	(11)
Net periodic benefit costs	$ (57)	$ 90	$ 1	$ 11

Amounts recognized in accumulated other comprehensive loss for the years ended December 31, 2015 and 2014 consist of the following:

	Year Ended December 31, 2015		Year Ended December 31, 2014	
Thousands of dollars	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Prior service cost	$ —	$ —	$ —	$ —
Net actuarial (gain) loss:				
Liability (gain) loss due to assumption change	(2,045)	(220)	474	88
Liability (gain) loss due to participant experience	(315)	(113)	22	(3)
Asset return loss	1,505	162	132	3
Net actuarial (gain) loss	(855)	(171)	628	88
Total	$ (855)	$ (171)	$ 628	$ 88

Estimated Future Benefit Payments

As of December 31, 2015 the following estimated benefit payments under the Plans, which reflect expected future service, as appropriate, are expected to be paid as follows:

Thousands of dollars	Pension Benefits	Postretirement Benefits
2016	$ 1,500	$ 150
2017	1,510	170
2018	1,540	190
2019	1,580	210
2020	1,650	230
2021-2025	8,620	1,060

ETSWDC expects to contribute approximately zero and $0.2 million to the pension plan and other postretirement plan, respectively, in 2016.

Assumptions

Assumptions used to determine the Plans' projected benefit obligations and costs as of December 31, 2015 and 2014 are as follows:

	December 31, 2015		December 31, 2014	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Discount rate	4.10%	4.10%	3.75%	3.75%
Rate of compensation increase	3.00%	N/A	3.00%	N/A
Health care cost trend rate:				
Pre - 65 rate	N/A	7.00%	N/A	7.00%
Post - 65 rate	N/A	7.00%	N/A	6.00%
Expected long-term rates of return on plan assets	6.75%	6.75%	6.50%	6.50%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A	4.5%	N/A	4.5%
Year that the rate reaches the ultimate trend rate	N/A	2023	N/A	2022

Assumptions used to determine net periodic benefit costs for the years ended December 31, 2015 and 2014 are as follows:

	December 31, 2015		December 31, 2014	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Discount rate	3.75%	3.75%	3.90%	3.75%
Expected long-term return on plan assets	6.50%	6.50%	6.50%	6.50%
Rate of compensation increase	3.00%	N/A	3.00%	N/A

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one-percentage point increase or decrease in assumed health care cost trend rates would increase or decrease total postretirement benefit service and interest costs by less than $0.1 million and would increase or decrease the postretirement benefit obligation by approximately $0.5 million and $0.4 million, respectively.

As of December 31, 2015 and 2014, we had $8.0 million and $9.6 million, respectively, of equity securities, consisting primarily of pooled separate accounts which focus on long-term growth of capital through U.S. and international services, and $12.0 million and $11.6 million, respectively, of fixed income securities, consisting primarily of pooled separate accounts which focus on long-term growth of capital and preservation of equity through U.S. and international securities.

As of December 31, 2015 and 2014, we had $0.1 million and $0.1 million, respectively, in cash and cash equivalents and $1.4 million and $1.4 million, respectively, in mutual funds, which focus on growth of capital and income maximization.

Plan Investment Policies and Strategies

The investment policies for the Plans reflect the funded status of the Plans and expectations regarding our future ability to make further contributions. Long-term investment goals are to: (1) manage the assets in accordance with the legal requirements of all applicable laws; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the Plans' investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation.

Historical performance and future expectations suggest that common stocks will provide higher total investment returns than fixed income securities over a long-term investment horizon. Short-term investments are utilized for pension payments, expenses, and other liquidity needs. As such, the Plan's targeted asset allocation is comprised of approximately 50 percent equity securities and approximately 50 percent high-yield bonds and other fixed income securities but may be adjusted to better match the plan's liabilities over time as the funded ratio (as defined by the investment policy) changes.

The Plans' assets are managed by a third party investment manager. The investment manager is limited to pursuing the investment strategies regarding asset mix and purchases and sales of securities within the parameters defined in the investment policy guidelines and investment management agreement. Investment performance and risk is measured and monitored on an ongoing basis through annual investment meetings and periodic cash flow studies.

Expected long-term return on plan assets

The overall expected long-term return on plan assets assumption is determined based on an asset rate-of-return modeling tool developed by a third party investment group. The tool utilizes underlying assumptions based on actual returns by asset category and inflation and takes into account the Plan's asset allocations to derive an expected long-term rate of return on those assets. Capital market assumptions reflect the long-term capital market outlook. The assumptions for equity and fixed income investments are developed using a building-block approach, reflecting observable inflation information and interest rate information available in the fixed income markets. Long-term assumptions for other asset categories are based on historical results, current market characteristics and the professional judgment of our internal and external investment teams.

Fair Value Measurements

Plan assets are measured at fair value. The following provides a description of the valuation techniques employed for each major plan asset class at December 31, 2015 and 2014.

Cash and cash equivalents – Cash and cash equivalents include cash on deposit which are valued using a market approach and are considered Level 1.

Mutual funds – Investments in mutual funds are valued using a market approach. The shares or units held are traded on the public exchanges and such prices are Level 1 inputs.

Pooled funds – Investments in pooled funds are valued using a market approach at the net asset value of units held, but investment opportunities in such funds are limited to institutional investors on the behalf of defined benefit plans. The various funds consist of either an equity or fixed income investment portfolio with underlying investments held in U.S. and non-U.S. securities. Nearly all of the underlying investments are publicly-traded. The majority of the pooled funds are benchmarked against a relative public index. These are considered Level 2.

14. Commitments and Contingencies

Lease Rental and Purchase Obligations

We have operating leases for office space and other property and equipment having initial or remaining non-cancelable lease terms in excess of one year. Our future minimum rental payments for operating leases at December 31, 2015 are presented below:

	Payments Due by Year						
Thousands of dollars	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**
Operating leases	$ 11,368	$ 11,323	$ 7,037	$ 5,615	$ 5,648	$ 14,480	$ 55,471

Net rental expense under non-cancelable operating leases was $8.9 million, $5.2 million and $3.9 million in 2015, 2014 and 2013, respectively.

Surety Bonds and Letters of Credit

In the normal course of business, we have performance obligations that are secured, in whole or in part, by surety bonds or letters of credit. These obligations primarily relate to abandonments, environmental and other responsibilities where governmental and other organizations require such support. These surety bonds and letters of credit are issued by financial institutions and are required to be reimbursed by us if drawn upon. At December 31, 2015, we had $27.1 million in surety bonds and $25.8 million in letters of credit outstanding, including $23.4 million in letters of credit related to the property reclamation deposit. At December 31, 2014, we had $21.1 million in surety bonds and $26.5 million in letters of credit outstanding.

Legal Proceedings

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

15. Partners' Equity

Preferred Units

On April 8, 2015, we issued in private offerings $350 million of 8.0% Series B Perpetual Convertible Preferred Units ("Series B Preferred Units") to EIG Redwood Equity Aggregator, LP ("EIG Equity"), ACMO BBEP Corp. ("ACMO") and certain other purchasers at an issue price of $7.50 per unit. We received approximately $337.2 million from this offering, net of fees and estimated expenses, which we primarily used to repay borrowings under our credit facility. The Series B Preferred Units rank senior to the Common Units and on parity with the Series A Preferred Units (as defined below) with respect to the payment of current distributions.

Distributions on the Series B Preferred Units are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by our Board of Directors out of legally available funds for such purpose. For the first monthly distribution on April 24, 2015, we declared a distribution on the Series B Preferred Units, which we elected to pay in kind by issuing additional Series B Preferred Units (or, if elected by the unitholder, by issuing Common Units in lieu of such Series B Preferred Units) in lieu of cash of 0.008222 Series B Preferred Unit per unit, which was paid on May 15, 2015. Regular monthly distributions of 0.006666 Series B Preferred Unit began with the June 15, 2015 payment. During the year ended December 31, 2015, we recognized $20.8 million of accrued distributions on the Series B Preferred Units, which are included in non-cash distributions to Series B preferred unitholders on the consolidated statements of operations.

On April 8, 2015, we entered into a registration rights agreement ("Registration Rights Agreement") with purchasers of the Series B Preferred Units, including EIG Equity, relating to the registered resale of (1) the Series B Preferred Units, including paid in kind units, and (2) Common Units issuable upon conversion of the Series B Preferred Units, including paid in kind units (the "Registrable Securities"). In certain circumstances, the purchasers of Series B Preferred Units will have piggyback registration rights and rights to request an underwritten offering as described in the Registration Rights Agreement. The Registrable Securities are registered under a shelf registration statement on Form S-3, which was declared effective by the SEC on September 11, 2015.

On May 21, 2014, we sold 8.0 million 8.25% Series A Cumulative Redeemable Perpetual Preferred Units ("Series A Preferred Units") in a public offering at a price of $25.00 per Preferred Unit, resulting in proceeds of $193.2 million, net of underwriting discounts and offering expenses of $6.8 million. We used the net proceeds from this offering to repay indebtedness outstanding under our credit facility.

The Series A Preferred Units rank senior to our Common Units and on parity with the Series B Preferred Units with respect to the payment of current distributions. Distributions on Series A Preferred Units are cumulative from the date of original issue and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by our board of directors out of legally available funds for such purpose. We pay cumulative distributions in cash on the Series A Preferred Units on a monthly basis at a monthly rate of $0.171875 per Series A Preferred Unit. During the years ended December 31, 2015 and 2014, we recognized $16.5 million and $10.1 million, respectively, of accrued distributions on the Series A Preferred Units, which are included in the distributions to preferred unitholders on the consolidated statements of operations and paid $16.5 million and $9.4 million, respectively.

The Series A Preferred Units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into Common Units in connection with a change in control. At any time on or after May 15, 2019, we may, at our option, redeem the Series A Preferred Units, in whole or in part, at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption. In addition, we may redeem the Series A Preferred Units at the same redemption price following certain changes of control, as described in the Partnership Agreement (as defined below); if we do not exercise this option, then the holders of the Series A Preferred Units have the option to convert the Series A Preferred Units into a number of Common Units per Preferred Unit as set forth in the Partnership Agreement. If we exercise the right to redeem all outstanding Series A Preferred Units, the holders of Series A Preferred Units will not have the conversion right described above.

Common Units

At December 31, 2015 and 2014, we had 213.5 million and 210.9 million in Common Units outstanding, respectively.

During the years ended December 31, 2015 and 2014, approximately 1.6 million and 0.6 million Common Units, respectively, were issued to employees and outside directors pursuant to vested grants under our First Amended and Restated 2006 Long Term Incentive Plan ("LTIP").

At each of the years ended December 31, 2015 and 2014, we had 24.7 million and 9.7 million of Common Units, respectively, authorized for issuance under our long-term incentive compensation plans, and there were 14.1 million and 3.3 million of units available at December 31, 2015 and 2014, respectively, for future issuance of Common Units.

Pursuant to an Equity Distribution Agreement dated as of March 19, 2014 (the "Equity Distribution Agreement"), we may sell, from time to time up to $200 million in Common Units. We intend to use the net proceeds of any sales pursuant to the Equity Distribution Agreement, after deducting commissions and offering expenses, for general purposes, which may include, among other things, repayment of indebtedness, acquisitions, capital expenditures and additions to working capital. The Common Units to be issued are registered under a shelf registration statement on Form S-3, which was declared effective by the SEC on January 22, 2014. During the years ended December 31, 2015 and 2014, we issued approximately 0.5 million and 1.3 million Common Units, respectively, under the Equity Distribution Agreement for net proceeds of $3.1 million and $26.2 million, respectively.

In October 2014, we sold 14 million Common Units at a price to the public of $18.64 per Common Unit. We used the net proceeds, net of underwriting discounts and offering expenses, of $251.6 million to reduce outstanding borrowings under our credit facility.

In October 2014, we issued 4.3 million Common Units to Antares as partial consideration for the Antares Acquisition. The fair value of the units on the date of the acquisition was $16.91 per unit, or $72.7 million.

In November 2014, we issued 71.5 million Common Units to QRE as partial consideration for the QRE Merger. The fair value of the units on the date of the acquisition was $14.73 per unit, or $1.06 billion.

In February 2013, we sold approximately 14.95 million Common Units at a price to the public of $19.86 per Common Unit, resulting in net proceeds of $285.0 million, after deducting underwriting discounts and expenses. In November 2013, we sold 18.98 million Common Units at a price to the public of $18.22 per Common Unit resulting in net proceeds net of $333.2 million, after deducting underwriting discounts and estimated offering expenses.

Earnings per Common Unit

FASB Accounting Standards require use of the "two-class" method of computing earnings per unit for all periods presented. The "two-class" method is an earnings allocation formula that determines earnings per unit for each class of common unit and participating security as if all earnings for the period had been distributed. Unvested restricted unit awards that earn non-forfeitable distribution rights qualify as participating securities and, accordingly, are included in the basic computation. Our unvested Restricted Phantom Units ("RPUs") and Convertible Phantom Units ("CPUs") participate in distributions on an equal basis with Common Units. Accordingly, the presentation below is prepared on a combined basis and is presented as net income (loss) per common unit.

The following is a reconciliation of net income (loss) and weighted average units for calculating basic net income (loss) per common unit and diluted net income (loss) per common unit.

	Year Ended December 31,		
Thousands, except per unit amounts	**2015**	**2014**	**2013**
Net (loss) income attributable to the partnership	$ (2,583,339)	$ 421,333	$ (43,671)
Less:			
Net income (loss) attributable to participating units	—	5,348	—
Distributions on participating units in excess of earnings	1,731	—	—
Distributions to Series A preferred unitholders	16,500	10,083	—
Non-cash distributions to Series B preferred unitholders	20,817	—	—
Net (loss) income used to calculate basic and diluted net (loss) income per unit	$ (2,622,387)	$ 405,902	$ (43,671)
Weighted average number of units used to calculate basic and diluted net income (loss) per unit:			
Common Units	211,575	133,451	101,604
Dilutive units (a)	—	755	—
Denominator for diluted net (loss) income per unit	211,575	134,206	101,604
Net (loss) income per common unit			
Basic	$ (12.39)	$ 3.04	$ (0.43)
Diluted	$ (12.39)	$ 3.02	$ (0.43)

(a) The years ended December 31, 2015 and December 31, 2013 exclude 725 and 364 weighted average anti-dilutive units, respectively, from the calculation of the denominator for diluted earnings per common unit, as we were in a loss position.

Cash Distributions on Common Units

The partnership agreement requires us to distribute all of our available cash quarterly. Available cash is cash on hand, including cash from borrowings, at the end of a quarter after the payment of expenses and the establishment of reserves for future capital expenditures and operational needs. We may fund a portion of capital expenditures with additional borrowings or issuances of additional units. We may also borrow to make distributions to unitholders, for example, in circumstances where we believe that the distribution level is sustainable over the long term, but short-term factors have caused available cash from operations to be insufficient to pay the distribution at the current level. The partnership agreement does not restrict our ability to borrow to pay distributions. The cash distribution policy reflects a basic judgment that unitholders will be better served by us distributing our available cash, after expenses and reserves, rather than retaining it. Distributions are not cumulative. Consequently, if distributions on Common Units are not paid with respect to any fiscal quarter at the initial distribution rate, our unitholders will not be entitled to receive such payments in the future.

Prior to the fourth quarter of 2013, for the quarters for which we declared a distribution, distributions were paid within 45 days of the end of each fiscal quarter to holders of record on or about the first or second week of each such month. If the distribution date does not fall on a business day, the distribution will be made on the business day immediately preceding the indicated distribution date. On October 30, 2013, we amended our First Amended and Restated Agreement of Limited Partnership by adopting Amendment No. 5, which provided that, at the discretion of our General Partner, for the quarters for which we declare a distribution, we may pay distributions within 45 days following the end of each quarter or in three equal monthly payments within 17, 45 and 75 days following the end of each quarter. We changed our distribution payment policy from a quarterly payment schedule to a monthly payment schedule beginning with the distributions relating to the fourth quarter of 2013.

We do not have a legal obligation to pay distributions at any rate except as provided in the partnership agreement. Our distribution policy is consistent with the terms of our partnership agreement, which requires that we distribute all of our available cash quarterly. Under the partnership agreement, available cash is defined to generally mean, for each fiscal quarter, cash generated from our business in excess of the amount of reserves our General Partner determines is necessary or appropriate to provide for the conduct of the business, to comply with applicable law, any of its debt instruments or other agreements or to provide for future distributions to its unitholders for any one or more of the upcoming four quarters. The partnership agreement provides that any determination made by our General Partner in its capacity as general partner must be made in good faith and that any such determination will not be subject to any other standard imposed by the partnership agreement, the Delaware limited partnership statute or any other law, rule or regulation or at equity.

During the years ended December 31, 2015, 2014 and 2013, we paid cash distributions of approximately $123.2 million, $261.0 million and $183.6 million, respectively, to our common unitholders. The distributions that were paid to unitholders totaled $0.58, $2.00 and $1.91 per Common Unit, respectively. We also paid cash equivalent on the distributions paid to our unitholders of $3.0 million, $3.8 million and $3.3 million, respectively, to holders of outstanding RPUs and CPUs issued under our LTIP.

Effective November 30, 2015, distributions on common units were suspended by the Board of Directors, thus there are no common unit distributions attributable to the fourth quarter 2015 or the third monthly payment of the distribution attributable to the third quarter.

16. Accumulated Other Comprehensive Income (Loss)

Changes in accumulated other comprehensive income (loss) by component, net of tax, were as follows:

	Gain (loss) on		
Thousands of dollars	Available-For-Sale Securities	Pension and Postretirement Benefits	Total
Accumulated comprehensive loss as of December 31, 2013	$ —	$ —	$ —
Amounts reclassified from accumulated other comprehensive loss (a)	(189)	(473)	(662)
Net current period other comprehensive loss	(189)	(473)	(662)
Accumulated comprehensive loss as of December 31, 2014	(189)	(473)	(662)
Less: Accumulated comprehensive loss attributable to non-controlling interest	(77)	(193)	(270)
Accumulated comprehensive loss attributable to the Partnership as of December 31, 2014	(112)	(280)	(392)
Other comprehensive (loss) income before reclassification	(267)	677	410
Amounts reclassified from accumulated other comprehensive loss (a)	(135)	—	(135)
Net current period other comprehensive (loss) income	(402)	677	275
Accumulated comprehensive (loss) income as of December 31, 2015	(514)	397	(117)
Less: Accumulated comprehensive (loss) income attributable to non-controlling interest	(164)	276	112
Accumulated comprehensive (loss) income attributable to the Partnership as of December 31, 2015	$ (350)	$ 121	$ (229)

(a) Amounts were reclassified from accumulated other comprehensive income (loss) to other expense (income), net on the consolidated statements of operations.

17. Noncontrolling interest

FASB Accounting Standards require that noncontrolling interests be classified as a component of equity and establish reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners.

We have a 59% controlling interest in ETSWDC and have consolidated ETSWDC into our consolidated financial statements. The noncontrolling interest in ETSWDC at December 31, 2015 and 2014 was $7.3 million and $6.9 million, respectively. The main purpose of ETSWDC is to dispose of salt water generated as a by-product from oil produced in certain East Texas oil fields.

18. Unit Based Compensation Plans

FASB Accounting Standards establish requirements for charging compensation expenses based on fair value provisions. At December 31, 2015, the RPUs and the CPUs granted to employees and directors under LTIP were all classified as equity awards. These awards are being recognized as compensation expense on a straight line basis over the annual vesting periods as prescribed in the award agreements.

We recognized $26.8 million, $23.4 million and $20.0 million of compensation expense related to our various awards for the years ended December 31, 2015, 2014 and 2013, respectively. Unit-based compensation expense of $25.5 million was included in general and administrative expenses and $1.3 million was included in restructuring costs for the year ended December 31, 2015. See Note 21 for a discussion of restructuring costs.

Restricted Phantom Units

RPUs are phantom equity awards that, to the extent vested, represent the right to receive actual partnership units upon specified payment events. Certain of our employees including our executives are eligible to receive RPU awards. RPUs generally vest in three equal annual installments on each anniversary of the vesting commencement date of the award. In addition, each RPU is granted in tandem with a distribution equivalent right that will remain outstanding from the grant of the RPU until the earlier to occur of its forfeiture or the payment of the underlying unit, and which entitles the grantee to receive payment of amounts equal to distributions paid to each holder of an actual partnership unit during such period. RPUs that do not vest for any reason are forfeited upon a grantee's termination of employment.

The fair value of the RPUs is determined based on the fair market value of our units on the date of grant. RPU awards were granted to Breitburn Management employees during the years ended December 31, 2015, 2014 and 2013 as shown in the table below. We recorded compensation expense of $20.2 million, $18.3 million and $17.0 million in 2015, 2014 and 2013, respectively, related to the amortization of outstanding RPUs over their related vesting periods. In connection with the workforce reduction (see Note 21), $1.3 million was recognized as restructuring costs for accelerated vesting of 0.1 million LTIP grants for certain individuals. As of December 31, 2015, there was $23.3 million of total unrecognized compensation cost remaining for the unvested RPUs. This amount is expected to be recognized over the next two years. The total grant date fair value of units that vested during the years ended December 31, 2015, 2014 and 2013 was $19.7 million, $18.4 million and $17.2 million, respectively.

The following table summarizes information about RPUs:

	Year Ended December 31,					
	2015		2014		2013	
Thousands, except per unit amounts	Number of RPUs	Weighted Average Fair Value	Number of RPUs	Weighted Average Fair Value	Number of RPUs	Weighted Average Fair Value
Outstanding, beginning of period	957	$ 20.98	896	$ 21.05	817	$ 20.92
Granted	4,739	6.46	1,025	20.21	919	20.77
Vested (a)	(2,012)	10.63	(906)	20.22	(833)	20.62
Canceled	(646)	8.24	(58)	20.36	(7)	21.60
Outstanding, end of period	3,038	$ 7.90	957	$ 20.98	896	$ 21.05

(a) Includes 613, 298 and 308 units canceled at the time of distribution for income tax liability payments we made on behalf of the restricted unit grantees for years ended December 31, 2015, 2014 and 2013, respectively.

Convertible Phantom Units

On January 28, 2013, the Compensation and Governance Committee approved grants to certain executives under the First Amended and Restated Partnership 2006 Long-Term Incentive Plan of CPUs in tandem with a corresponding Performance Distribution Right ("PDR") which will remain outstanding from the Grant Date until the earlier to occur of a Payment Date or the forfeiture of the CPU to which such PDR corresponds. Each CPU granted was issued in tandem with a corresponding PDR, which entitles the Participant to receive an amount determined by reference to Partnership distributions and which will be credited to the Participant in the form of additional CPUs equal to the product of (i) the aggregate per Unit distributions paid by the Partnership in respect of each quarter through which the PDR remains outstanding (provided that the PDR is outstanding as of the record date set by the Board of Directors of the Company for such distribution) (including any extraordinary non-recurring distributions paid during a quarter), if any, times (ii) the number of common unit equivalents ("CUEs") underlying the relevant CPU during such quarter, divided by the closing price of the Unit on the date on which such distribution is paid to Unitholders. All such PDRs will be credited to the Participant in the form of additional CPUs as of the date of payment of any such distribution based on the Fair Market Value of a Unit on such date. Each additional CPU which results from such crediting of PDRs granted hereunder will be subject to the same vesting, forfeiture, payment or distribution, adjustment and other provisions which apply to the underlying CPU to which such additional CPU relates. PDRs do not entitle the Participant to any amounts relating to distributions occurring after the earlier to occur of the applicable Payment Date or the Participant's forfeiture of the CPU to which such PDR relates in accordance herewith. The CPUs will vest and the number of CUEs underlying such CPUs (if any) on the earliest to occur of (i) an applicable accelerated vesting date, and (ii) December 28, 2015, in each case subject to the Participant's continued employment with the Partnership through any such date. CPUs that vest will represent the right to receive payment in the form of a number of Units equal to (i) the product of (A) the number of CPUs so vested, times (B) the number of CUEs underlying such CPUs on the applicable Vesting Date, minus (ii) the applicable number of PDR Equalization Units, if any (such number of Units, the "Resultant Units"). Unless and until a CPU vests, the Participant will have no right to payment of Units in respect of any such CPU. Prior to actual payment in respect of any vested CPU, such CPU will represent an unsecured obligation of the Partnership, payable (if at all) only from the general assets of the Partnership.

On January 28, 2013, 0.3 million CPUs ("2013 CPUs") were granted at a price of $20.98 per Common Unit and on January 29, 2014, an additional 0.3 million CPUs ("2014 CPUs") were granted at a price of $20.29 per Common Unit. We recorded compensation expense for the 2013 and 2014 CPUs of approximately $4.3 million in each of the years 2015 and 2014. In 2013, we recorded $2.3 million to compensation expense for the 2013 CPUs. As of December 31, 2015, the 2013 CPUs were fully vested and the 2014 CPUs remained unvested and outstanding with $2.0 million of unrecognized compensation cost remaining.

On January 26, 2015, the Compensation and Governance Committee approved an amendment to each of the existing CPU Agreements for grants made in 2013 and 2014. Prior to this amendment of the CPU Agreements, the number of CUEs per CPU over the three year life of the agreement could be reduced to a minimum of zero or be multiplied by a maximum of 4.768 times based on the Partnership's distribution levels. The amendment to the CPU agreements, commencing with the date of the amendment, now limits the multiplier to "1." As a result at vesting, CPUs for each award will convert to Common Units on a 1:1 basis. In addition, the amendment provided for the forfeiture from the date of grant to the date of the amendment of previously credited PDRs to each executive. No other modification was made to the CPU Agreements under this amendment.

Director Restricted Phantom Units

We have made grants of RPUs to the non-employee directors of our General Partner that are substantially similar to the ones granted to employees. The estimated fair value associated with these phantom units is expensed over the vesting period.

We recorded compensation expense for the director's phantom units of approximately \$0.9 million, \$0.8 million and \$0.7 million in 2015, 2014 and 2013, respectively. As of December 31, 2015, there was \$1.0 million of total unrecognized compensation cost for the unvested Director Restricted Phantom Units and such cost is expected to be recognized over the next two years.

The following table summarizes information about the Director Restricted Phantom Units:

	Year Ended December 31,					
	2015		2014		2013	
Thousands, except per unit amounts	Number of Units	Weighted Average Fair Value	Number of Units	Weighted Average Fair Value	Number of Units	Weighted Average Fair Value
Outstanding, beginning of period	78	$ 20.44	67	$ 20.69	48	$ 20.43
Granted	160	6.56	43	20.29	38	20.98
Vested	(37)	20.35	(32)	20.77	(19)	20.63
Outstanding, end of period	201	$ 9.42	78	$ 20.44	67	$ 20.69

19. Retirement Plan

Breitburn Management operates our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. All of our employees, including our executives, are employees of Breitburn Management. Breitburn Management has a defined contribution retirement plan, which covers substantially all of its employees commencing on the first day of the month following the month of hire. The plan provides for Breitburn Management to make regular contributions based on employee contributions as provided for in the plan agreement. Employees fully vest in Breitburn Management's contributions after five years of service. PCEC is charged for a portion of the matching contributions made by Breitburn Management. For the years ended December 31, 2015, 2014 and 2013, we recognized expense related to matching contributions of \$3.6 million, \$3.7 million and \$2.0 million, respectively.

20. Significant Customers

We sell oil, NGLs and natural gas primarily to large, established domestic refiners and utilities. For the years ended December 31, 2015, 2014 and 2013, sales of oil, NGL and natural gas production to each of the following purchasers represented 10% or more of total sales revenue:

	Year Ended December 31,		
	2015	2014	2013
Shell Trading	24%	22%	15%
Plains Marketing	12%	(a)	(a)
Phillips 66	(a)	10%	15%
Marathon Oil Corporation	(a)	(a)	10%

(a) Represented less than 10% of total sales revenue for the respective year end.

Our sales contracts are sold at market-sensitive or spot prices. Because commodity products are sold primarily on the basis of price and availability, we are not dependent upon one purchaser or a small group of purchasers. As a result, the loss of any one purchaser would not have a long-term material adverse effect on our ability to sell our production.

21. Restructuring Costs

In the first quarter of 2015, we executed a workforce reduction plan as part of a company-wide reorganization effort intended to reduce costs, due in part to lower commodity prices. The reduction was communicated to affected employees on various dates, and all such notifications were completed by March 31, 2015. The plan resulted in a reduction of approximately 37 employees. In April 2015, we communicated further reductions to an additional 8 employees. For the year ended December 31, 2015, we recognized a total cost of $6.4 million, which included severance cash payments of $4.8 million, unit-based compensation of $1.3 million and other termination costs of $0.3 million. Total workforce reductions in 2015 as a result of the workforce reduction plan, voluntary resignations and early retirement exceed 60 positions.

22. Subsequent Events

On January 4, 2016 and January 28, 2016, we declared cash distributions for our Series A Preferred Units of $0.171875 per Series A Preferred Unit, which is expected to be paid on February 15, 2016 and March 15, 2016, respectively, to record holders of our Series A Preferred Units at the close of business on January 29, 2016 and February 29, 2016, respectively. The monthly distribution rate is equal to an annual distribution of $2.0625 per Series A Preferred Unit.

On January 4, 2016 and January 28, 2016 we declared distributions on our Series B Preferred Units, which we elected to pay in kind by issuing additional Series B Preferred Units (or, if elected by the unitholder, by issuing Common Units in lieu of such Series B Preferred Units) of 0.006666 Series B Preferred Unit per unit, payable on January 15, 2016 and February 15, 2016, respectively, to record holders of Series B Preferred Units at the close of business on December 31, 2015 and January 29, 2016, respectively.

Supplemental Information (Unaudited)

A. Oil, NGL and Natural Gas Activities (Unaudited)

Our proved reserves are estimated by third party reservoir engineers and in accordance with SEC guidelines. We are reasonably certain that the estimated quantities will equal or exceed the estimates. Reserve estimates are expected to change as economic assumptions change and additional engineering and geoscience data becomes available. For reserve reporting purposes, we use unweighted average first-day-of-the-month pricing for the 12 calendar months prior to the end of the reporting period. Costs are held constant throughout the projected reserve life. While SEC guidelines permit a company to establish undeveloped reserves as proved with appropriate degrees of reasonable certainty established absent actual production tests and without artificially limiting such reserves to spacing units adjacent to a producing well, we have elected not to add such undeveloped reserves as proved.

Costs incurred

The following table summarizes our costs incurred for the past three years:

	Year Ended December 31,		
Thousands of dollars	**2015**	**2014**	**2013**
Property acquisition costs			
Proved	$ 7,943	$ 1,707,528	$ 971,968
Unproved (a)	2,593	734,603	88,276
Pipelines and processing facilities	—	—	72,037
Asset retirement costs	492	91,097	9,171
Development costs	201,859	388,807	294,822
Asset retirement costs - development	2,268	4,020	9,612
Total costs incurred	$ 215,155	$ 2,926,055	$ 1,445,886

(a) Primarily reflects amounts attributable to unproved reserves located within acquired producing oil and gas properties.

Capitalized costs

The following table presents the aggregate capitalized costs subject to DD&A relating to oil and gas activities, and the aggregate related accumulated allowance:

	December 31,	
Thousands of dollars	**2015**	**2014**
Proved properties and related producing assets	$ 6,502,029	$ 6,402,997
Pipelines and processing facilities	342,224	316,002
Unproved properties (a)	1,053,834	1,017,410
Accumulated depreciation, depletion and amortization	(4,113,741)	(1,326,566)
Net capitalized costs	$ 3,784,346	$ 6,409,843

(a) Primarily reflects amounts attributable to unproved reserves located within acquired producing oil and gas properties.

The average DD&A rate per equivalent unit of production for the years ended December 31, 2015 and 2014, excluding impairments and non-oil and gas related DD&A, were $22.24 per Boe and $20.44 per Boe, respectively.

Results of operations for oil, NGL and natural gas producing activities

The results of operations from oil, NGL and natural gas producing activities below exclude G&A expenses, interest expenses and interest income:

	Year Ended December 31,		
Thousands of dollars	**2015**	**2014**	**2013**
Oil, NGL and natural gas sales	$ 645,272	$ 855,820	$ 660,665
Gain (loss) on commodity derivative instruments, net	438,614	566,533	(29,182)
Operating costs	(440,533)	(352,906)	(262,822)
Depletion, depreciation and amortization	(448,791)	(288,503)	(210,636)
Impairment of oil and natural gas properties	(2,377,615)	(149,000)	(54,373)
Income tax benefit (expense)	(214)	91	(905)
Results of operations from producing activities (a)	$ (2,183,267)	$ 632,035	$ 102,747

(a) Excludes gain (loss) on sale of assets.

Supplemental reserve information

The following information summarizes our estimated proved reserves of oil, NGLs and natural gas and the present values thereof for the years ended December 31, 2015, 2014 and 2013. The following reserve information is based upon reports by Netherland, Sewell & Associates, Inc. ("NSAI") and Cawley, Gillespie & Associates, Inc. ("CGA"), independent petroleum engineering firms. NSAI prepared reserve data for all our properties, except for our Postle and North East Hardesty fields in Oklahoma, which was prepared by CGA. The estimates are prepared in accordance with SEC regulations. We only utilize large, widely known, highly regarded and reputable engineering consulting firms. Not only the firms, but the technical persons that sign and seal the reports are licensed and certify that they meet all professional requirements. Licensing requirements formally require mandatory continuing education and professional qualifications. They are independent petroleum engineers, geologists, geophysicists and petrophysicists.

Our reserve estimation process involves petroleum engineers and geoscientists. As part of this process, all reserves volumes are estimated using a forecast of production rates, current operating costs and projected capital expenditures. Reserves are based upon the unweighted average first-day-of-the-month prices for each year. Price differentials are then applied to adjust these prices to the expected realized field price. Specifics of each operating agreement are then used to estimate the net reserves. Production rate forecasts are derived by a number of methods, including decline curve analyses, volumetrics, material balance or computer simulation of the reservoir performance. Operating costs and capital costs are forecast using current costs combined with expectations of future costs for specific reservoirs. In many cases, activity-based cost models for a reservoir are utilized to project operating costs as production rates and the number of wells for production and injection vary.

The technical person, employed by our General Partner, primarily responsible for overseeing preparation of the reserves estimates and the third party reserve reports is Mark L. Pease, the President and Chief Operating Officer of our General Partner. Mr. Pease received a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines in 1979. Prior to joining our General Partner, Mr. Pease was Senior Vice President, E&P Technology & Services for Anadarko Petroleum Corporation. Mr. Pease has over 30 years of experience working in various capacities in the energy industry, including acquisition analysis, reserve estimation, reservoir engineering and operations engineering. Mr. Pease consults with CGA and NSAI during the reserve estimation process to review properties, assumptions and relevant data.

Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves reports included in this report as Exhibits 99.1 are Mr. C. Ashley Smith and Mr. Mike K. Norton. Mr. Smith, a Licensed Professional Engineer in the State of Texas (No. 100560), has been practicing consulting petroleum engineering at NSAI since 2006 and has over 5 years of prior industry experience. He graduated from University of Missouri-Rolla (Missouri University of Science & Technology) in 2000 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Norton has been practicing consulting petroleum geology at NSAI since 1989 and has over 10 years of prior industry experience. Mr. Norton is a Licensed Petroleum Geologist in the State of Texas (License No. 441) and has over 35 years of practical experience in petroleum geosciences, with over 30 years' experience in the estimation and evaluation of reserves. Mr. Norton graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. These technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Within CGA, the technical persons primarily responsible for preparing the estimates set forth in the CGA reserves report included in this report as Exhibit 99.2 is Mr. Robert Ravnaas, who has been a Petroleum Consultant for CGA since 1983, and became President in 2011. Mr. Ravnaas has completed numerous field studies, reserve evaluations and reservoir simulation, waterflood design and monitoring, unit equity determinations and producing rate studies. He has testified before the Texas Railroad Commission in unitization and field rules hearings. Prior to CGA Mr. Ravnaas worked as a Production Engineer for Amoco Production Company. Mr. Ravnaas received a B.S. with special honors in Chemical Engineering from the University of Colorado at Boulder, and a M.S. in Petroleum Engineering from the University of Texas at Austin. Mr. Ravnaas is a registered professional engineer in Texas, No. 61304, and a member of the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, the American Association of Petroleum Geologists and the Society of Professional Well Log Analysts.

Management believes the reserve estimates presented herein, in accordance with generally accepted engineering and evaluation methods and procedures consistently applied, are reasonable. However, there are numerous uncertainties inherent in estimating quantities and values of the estimated proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and gas that cannot be measured in an exact manner and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Because all reserve estimates are to some degree speculative, the quantities of oil, NGLs and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil, NGL and natural gas sales prices may all differ from those assumed in these estimates. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data. Therefore, the standardized measure of discounted net future cash flows shown below represents estimates only and should not be construed as the current market value of the estimated oil, NGL and natural gas reserves attributable to our properties. In this regard, the information set forth in the following tables includes revisions of reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent exploitation and development activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Decreases in the prices of oil, NGLs, and natural gas and increases in operating expenses have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and revenues, profitability and cash flow.

The following table sets forth certain data pertaining to our estimated proved reserves, all of which are located within the United States, for the years ended December 31, 2015, 2014 and 2013.

	Oil (in MBbls)	NGLs (in MBbls)	Natural Gas (in MMcf)	Total (MBoe)
Estimated Proved Reserves				
December 31, 2012	73,593	5,381	422,545	149,398
Revision of previous estimates	(3,312)	2,678	85,986	13,696
Purchase of previous reserves in-place	47,655	8,223	30,331	60,933
Sale of reserves in-place	(90)	—	—	(90)
Extensions, discoveries and other	1,014	48	1,527	1,317
Production	(5,651)	(640)	(28,156)	(10,983)
December 31, 2013	113,209	15,690	512,233	214,271
Revision of previous estimates	(20,005)	(5,798)	(1,589)	(26,067)
Purchase of previous reserves in-place	82,394	14,399	211,317	132,012
Sale of reserves in-place	—	—	—	—
Extensions, discoveries and other	7,172	651	8,297	9,206
Production	(7,931)	(1,157)	(30,159)	(14,114)
December 31, 2014	174,839	23,785	700,099	315,308
Revision of previous estimates	(44,387)	(3,553)	(141,618)	(71,544)
Purchase of previous reserves in-place	334	11	2,268	723
Sale of reserves in-place	—	—	—	—
Extensions, discoveries and other	9,538	1,322	24,293	14,910
Production	(11,190)	(1,953)	(41,876)	(20,123)
December 31, 2015	129,134	19,612	543,166	239,274
Proved developed reserves				
December 31, 2013	86,271	10,236	461,485	173,421
December 31, 2014	126,495	16,485	604,723	243,768
December 31, 2015	95,096	13,759	498,606	191,956
Proved undeveloped reserves				
December 31, 2013	26,938	5,454	50,748	40,850
December 31, 2014	48,344	7,300	95,376	71,540
December 31, 2015	34,038	5,853	44,560	47,318

Revisions of Previous Estimates

In 2015, we had negative revisions of 71.5 MMBoe, driven primarily by a decrease in commodity prices partially offset by an increase of 14.9 MMBoe related to extensions and discoveries. Unweighted average first-day-of-the-month oil and natural gas prices used to determine our total estimated proved reserves as of December 31, 2015 were $50.28 per Bbl of oil and $2.59 per MMBtu of gas, compared to $94.99 per Bbl of oil and $4.35 per MMBtu of gas in 2014. In 2014, we had negative revisions of 26.1 MMBoe, driven primarily by a decrease in oil and NGL prices in the Permian Basin, California, and Florida and performance revisions in the Permian Basin and Oklahoma and 9.2 MMBoe of extensions and discoveries.

Unweighted average first-day-of-the-month market prices for the reserve reports for the year ended December 31, 2013 were $96.94 per Bbl of oil, and $3.67 per MMBtu of gas. In 2013, we had positive revisions of 13.7 MMBoe, primarily related to an increase in oil and natural gas prices and 1.3 MMBoe of extensions and discoveries.

Conversion of Proved Undeveloped Reserves

During the years ended December 31, 2015, 2014 and 2013, we incurred $63.0 million, $272.0 million and $160.1 million in capital expenditures, respectively, and drilled 51 gross wells, 208 gross wells and 122 gross wells, respectively, related to the conversion of proved undeveloped to proved developed reserves. During the years ended December 31, 2015, 2014 and 2013, we converted 6.0 MMBoe, 10.5 MMBoe and 9.7 MMBoe, respectively, from proved undeveloped to proved developed reserves. As of December 31, 2015, we had no estimated proved undeveloped reserves that have remained undeveloped for more than five years, and we expect to develop substantially all estimated proved undeveloped reserves within five years of the recognition of those reserves.

The decrease in proved undeveloped reserves during the year ended December 31, 2015 was primarily due to the decrease in commodity prices partially offset by the conversion of 6.0 MMBoe proved undeveloped to proved developed reserves. The increase in proved undeveloped reserves during the year ended December 31, 2014 was primarily due to the QRE Merger, which added 36.0 MMBoe, and due to our expanded drilling program, primarily in California and the Permian Basin, partially offset by the conversion of proved undeveloped to proved developed reserves. The increase in proved undeveloped reserves during the year ended December 31, 2013 was primarily due to the Oklahoma Panhandle Acquisitions and the 2013 Permian Basin Acquisitions, which added 13.7 MMBoe and 9.5 MMBoe of proved undeveloped reserves, respectively, partially offset by economic revisions and the conversion of proved undeveloped to proved developed reserves.

Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows relating to our estimated proved oil and natural gas reserves as of December 31, 2015, 2014 and 2013 is presented below:

	December 31,		
Thousands of dollars	**2015**	**2014**	**2013**
Future cash inflows	$ 7,910,652	$ 20,014,316	$ 13,187,507
Future development costs	(1,070,048)	(1,904,400)	(962,517)
Future production expense	(4,394,562)	(8,445,646)	(5,703,997)
Future net cash flows	2,446,042	9,664,270	6,520,993
Discounted at 10% per year	(1,165,229)	(5,160,166)	(3,295,145)
Standardized measure of discounted future net cash flows	$ 1,280,813	$ 4,504,104	$ 3,225,848

The standardized measure of discounted future net cash flows discounted at 10% from production of proved reserves was developed as follows:

1. An estimate was made of the quantity of proved reserves and the future periods in which they are expected to be produced based on year-end economic conditions.
2. In accordance with SEC guidelines, the reserve engineers' estimates of future net revenues from our estimated proved properties and the present value thereof are made using unweighted average first-day-of-the-month oil and gas sales prices and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. We have entered into various derivative instruments to fix or limit the prices relating to a portion of our oil and gas production. Derivative instruments in effect at December 31, 2015 and 2014 are discussed in Note 4. Such derivative instruments are not reflected in the reserve reports. Representative unweighted average first-day-of-the-month market prices for the reserve reports for the year ended December 31, 2015 were $50.28 per Bbl of oil and $2.59 per MMBtu of gas, compared to $94.99 per Bbl of oil and $4.35 per MMBtu of gas in 2014. Unweighted average first-day-of-the-month market prices for the reserve reports for the year ended December 31, 2013 were $96.94 per Bbl of oil and $3.67 per MMBtu of gas.
3. The future gross revenue streams were reduced by estimated future operating costs (including production and ad valorem taxes) and future development and abandonment costs, all of which were based on current costs. Future net cash flows assume no future income tax expense as we are essentially a non-taxable entity except for four tax-paying corporations whose future income tax liabilities on a discounted basis are insignificant.

The principal sources of changes in the standardized measure of the future net cash flows for the years ended December 31, 2015, 2014 and 2013 are presented below:

	Year Ended December 31,		
Thousands of dollars	2015	2014	2013
Beginning balance	**$ 4,504,104**	**$ 3,225,848**	**$ 1,989,895**
Sales, net of production expense	(204,739)	(500,139)	(397,843)
Net change in sales and transfer prices, net of production expense	(3,787,527)	(29,497)	259,186
Previously estimated development costs incurred during year	501,097	315,792	176,253
Changes in estimated future development costs	106,577	(68,949)	(140,105)
Extensions, discoveries and improved recovery, net of costs	86,726	175,335	28,445
Purchase of reserves in place	7,943	1,707,528	1,044,004
Sale of reserves in place	—	—	(2,694)
Revision of quantity estimates and timing of estimated production	(383,778)	(644,399)	69,718
Accretion of discount	450,410	322,585	198,989
Ending balance	**$ 1,280,813**	**$ 4,504,104**	**$ 3,225,848**

B. Quarterly Financial Data (Unaudited)

	Year ended December 31, 2015			
Thousands of dollars except per unit amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Oil, NGL and natural gas sales	$ 162,623	$ 189,636	$ 153,325	$ 139,688
Gain (loss) on derivative instruments, net	137,192	(93,432)	253,012	141,842
Other revenue, net	6,469	6,504	5,922	5,934
Total revenue	306,284	102,708	412,259	287,464
Operating loss	(17,826)	(243,280)	(1,276,046)	(839,430)
Net loss (a)	(58,918)	(305,581)	(1,327,838)	(890,676)
Net loss attributable to the partnership	$ (58,825)	$ (305,707)	$ (1,327,929)	$ (890,878)
Basic net loss per common unit (b)	$ (0.29)	$ (1.46)	$ (6.17)	$ (4.25)
Diluted net loss per common unit (b)	$ (0.29)	$ (1.46)	$ (6.17)	$ (4.25)

(a) In the first quarter, third quarter and fourth quarter of 2015, we recognized and recorded impairment charges of $59.1 million, $1.4 billion and $878.3 million, respectively. The fourth quarter included $30.7 million in impairment charges for the correction of an error in the third quarter. This correction was not material to the third and the fourth quarter results. In the second quarter of 2015, we recorded a goodwill impairment charge of $95.9 million. See Note 6 for discussion of impairments.
(b) Due to changes in the number of weighted average common units outstanding that may occur each quarter, the sum of the earnings per unit amounts for the quarters may not be additive to the full year earnings per unit amount.

	Year ended December 31, 2014			
Thousands of dollars except per unit amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Oil, NGL and natural gas sales	$ 223,556	$ 219,051	$ 216,146	$ 197,067
(Loss) gain on derivative instruments, net	(40,228)	(127,000)	146,171	587,590
Other revenue, net	1,584	1,071	1,585	3,376
Total revenue	184,912	93,122	363,902	788,033
Operating income (loss)	20,399	(74,937)	160,219	440,286
Net (loss) income (a)	(9,758)	(104,725)	130,643	405,156
Net (loss) income attributable to the partnership	$ (9,758)	$ (104,725)	$ 130,643	$ 405,173
Basic net (loss) income per common unit (b)	$ (0.08)	$ (0.89)	$ 1.03	$ 2.28
Diluted net (loss) income per common unit (b)	$ (0.08)	$ (0.89)	$ 1.03	$ 2.27

(a) In the third quarter and fourth quarter of 2014, we recognized and recorded an impairment charge of $29.4 million and $119.6 million, respectively. See Note 6 for details on impairments.
(b) Due to changes in the number of weighted average common units outstanding that may occur each quarter, the sum of the earnings per unit amounts for the quarters may not be additive to the full year earnings per unit amount.

EXHIBIT INDEX

NUMBER	DOCUMENT
2.1	Agreement and Plan of Merger, dated as of July 23, 2014, by and among Breitburn Energy Partners LP, Breitburn GP LLC, Boom Merger Sub, LLC, QR Energy LP and QRE GP, LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by QR Energy, LP on July 29, 2014).
3.1	Certificate of Limited Partnership of Breitburn Energy Partners LP (incorporated herein by reference to Exhibit 3.1 to Amendment No. 1 to Form S-1 (File No. 333-134049) filed on July 13, 2006).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Breitburn Energy Partners LP (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q (File No. 001-33055) filed on May 5, 2015.
3.3	Third Amended and Restated Agreement of Limited Partnership of Breitburn Energy Partners LP (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on April 14, 2015).
3.4	Fourth Amended and Restated Limited Liability Company Agreement of Breitburn GP LLC dated as of April 5, 2010 (incorporated herein by reference to Exhibit 3.2 to the Current Report on Form 8-K (File No. 001-33055) filed on April 9, 2011).
3.5	Amendment No. 1 to the Fourth Amended and Restated Limited Liability Company Agreement of Breitburn GP LLC dated as of December 30, 2010 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on January 6, 2011).
3.6	Amendment No. 2 to the Fourth Amended and Restated Limited Liability Company Agreement of Breitburn GP LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on July 2, 2014).
4.1	Indenture, dated as of October 6, 2010, by and among Breitburn Energy Partners LP, Breitburn Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated herein by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-33055) filed on October 7, 2010).
4.2	Indenture, dated as of January 13, 2012, by and among Breitburn Energy Partners LP, Breitburn Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated herein by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-33055) filed on January 13, 2012).
4.3	Indenture, dated as of April 8, 2015, by and among Breitburn Energy Partners LP, Breitburn Operating LP, Breitburn Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated herein by reference to Exhibit 10.4 to the Current Report on Form 8-K (File No. 001-33055) filed on April 14, 2015).
4.4	First Supplemental Indenture, dated as of August 8, 2013, by and among Breitburn Energy Partners LP, Breitburn Finance Corporation, the Guarantors named therein and U.S. Bank National Association, to the Indenture, dated as of October 6, 2010 (incorporated herein by reference to Exhibit 4.3 to the Current Report on Form 8-K (File No. 001-33055) filed on November 22, 2013).
4.5	First Supplemental Indenture, dated as of August 8, 2013, by and among Breitburn Energy Partners LP, Breitburn Finance Corporation, the Guarantors named therein and U.S. Bank National Association, to the Indenture dated as of January 13, 2012 (incorporated herein by reference to Exhibit 4.2 to the Current Report on Form 8-K (File No. 001-33055) filed on November 22, 2013).
4.6	Second Supplemental Indenture, dated as of November 24, 2014, by and among Breitburn Energy Partners LP, Breitburn Finance Corporation, the Guarantors named therein and U.S. Bank National Association, to the Indenture, dated as of October 6, 2010 (incorporated herein by reference to Exhibit 4.8 to Post-Effective Amendment No. 2 to Form S-3 (File No. 001-181531) filed on November 24, 2014).
4.7	Second Supplemental Indenture, dated as of November 24, 2014, by and among Breitburn Energy Partners LP, Breitburn Finance Corporation, the Guarantors named therein and U.S. Bank National Association, to the Indenture dated as of January 13, 2012 (incorporated herein by reference to Post-Effective Amendment No. 2 to Form S-3 (File No. 001-181531) filed on November 24, 2014).
4.8	Registration Rights Agreement, dated July 23, 2014, by and among Breitburn Energy Partners LP, QR Holdings (QRE), LLC, QR Energy Holdings, LLC, Quantum Resources B, LP, Quantum Resources A1, LP, Quantum Resources C, LP, QAB Carried WI, LP, QAC Carried WI, LP and Black Diamond Resources, LLC (incorporated herein by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by QR Energy, LP on July 29, 2014).

4.9	Registration Rights Agreement, dated April 8, 2015, by and among Breitburn Energy Partners LP and the purchasers listed on Schedule A thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on April 14, 2015).
10.1	Third Amended and Restated Credit Agreement, dated November 19, 2014, by and among Breitburn Operating LP, as borrower, Breitburn Energy Partners LP, as parent guarantor, and Wells Fargo Bank National Association as administrative agent (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on November 29, 2014).
10.2	First Amendment to Third Amended and Restated Credit Agreement, dated as of April 8. 2015, by and among Breitburn Operating LP, as borrower, Breitburn Energy Partners LP, as parent guarantor, Breitburn GP LLC, Breitburn Operating GP LLC, the subsidiary guarantors named therein, each lender signatory thereto and Wells Fargo Bank, National Association (incorporated herein by reference to Exhibit 10.7 to the Current Report on Form 8-K (File No. 001-33055) filed on April 14, 2015).
10.3	Amended and Restated Series B Preferred Unit Purchase Agreement, dated as of April 8, 2015, by and among Breitburn Energy Partners LP, EIG Redwood Equity Aggregator, LP, ACMO BBEP Corp. and the other purchasers listed on Schedule A thereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on April 14, 2015).
10.4	Board Representation and Standstill Agreement, dated as of April 8, 2015, by and among Breitburn GP LLC, Breitburn Energy Partners LP and EIG Redwood Equity Aggregator, LP (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K (File No. 001-33055) filed on April 14, 2015).
10.5	Amended and Restated Purchase Agreement, dated as of April 8, 2015, by and among Breitburn Energy Partners LP, Breitburn Operating LP, Breitburn Finance Corporation, the guarantors party thereto and the purchasers listed on Schedule I thereto (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K (File No. 001-33055) filed on April 14, 2015).
10.6	Security Agreement, dated as of April 8, 2015, by and among Breitburn Operating LP, Breitburn Energy Partners LP, Breitburn Finance Corporation, each of the subsidiary entities named therein and U.S. Bank National Association (incorporated herein by reference to Exhibit 10.5 to the Current Report on Form 8-K (File No. 001-33055) filed on April 14, 2015).
10.7	Intercreditor Agreement, dated as of April 8, 2015, by and among Wells Fargo Bank, National Association, U.S. Bank National Association, Breitburn Energy Partners LP, Breitburn Finance Corporation, Breitburn Operating LP and each of the subsidiary entities named therein (incorporated herein by reference to Exhibit 10.6 to the Current Report on Form 8-K (File No. 001-33055) filed on April 14, 2015).
10.8	Third Amended and Restated Administrative Services Agreement, dated May 8, 2012, by and between Pacific Coast Energy Company L.P. and Breitburn Management Company LLC (incorporated herein by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2012 (File No. 001-33055) filed on August 8, 2012).
10.9	Amendment No. 1 to the Third Amended and Restated Administrative Services Agreement between Pacific Coast Energy Company LP and Breitburn Management Company LLC dated March 18, 2014 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on March 20, 2014).
10.10	Amendment No. 2 to the Third Amended and Restated Administrative Services Agreement between Pacific Coast Energy Company LP and Breitburn Management Company LLC dated June 30, 2014 (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2014 (File No. 001-33055) filed on November 5, 2014).
10.11	Amendment No. 3 to the Third Amended and Restated Administrative Services Agreement between Pacific Coast Energy Company LP and Breitburn Management Company LLC dated July 31, 2014 (incorporated herein by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2014 (File No. 001-33055) filed on November 5, 2014).
10.12	Amendment No. 4 to the Third Amended and Restated Administrative Services Agreement between Pacific Coast Energy Company LP and Breitburn Management Company LLC dated August 29, 2014 (incorporated herein by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2014 (File No. 001-33055) filed on November 5, 2014).
10.13	Amendment No. 5 to the Third Amended and Restated Administrative Services Agreement between Pacific Coast Energy Company LP and Breitburn Management Company LLC dated May 1, 2015 (incorporated hereby by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2015 (File No. 001-33055) filed on May 5, 2015.
10.14*	Amendment No. 6 to the Third Amended and Restated Administrative Services Agreement between Pacific Coast Energy Company LP and Breitburn Management Company LLC dated December 22, 2015.

10.15*	Amendment No. 7 to the Third Amended and Restated Administrative Services Agreement between Pacific Coast Energy Company LP and Breitburn Management Company LLC dated January 29, 2016.
10.16	Omnibus Agreement, dated August 26, 2008, by and among Breitburn Energy Holdings LLC, BEC (GP) LLC, Breitburn Energy Company LP, Breitburn GP LLC, Breitburn Management Company LLC and Breitburn Energy Partners LP (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K (File No. 001-33055) filed on September 2, 2008).
10.17	First Amendment to Omnibus Agreement, dated May 8, 2012, by and among Breitburn Energy Partners LP, Breitburn GP LLC, Breitburn Management Company LLC, Pacific Coast Energy Company L.P., Pacific Coast Energy Holdings LLC and PCEC (GP) LLC (incorporated herein by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2012 (File No. 001-33055) filed on August 8, 2012).
10.18	Amendment No. 1 to the Operations and Proceeds Agreement, relating to the Dominguez Field and dated October 10, 2006 entered into on June 17, 2008 by and between BreitBurn Energy Company L.P. and Breitburn Operating LP (incorporated herein by reference to Exhibit 10.6 to the Current Report on Form 8-K (File No. 001-33055) filed on June 23, 2008).
10.19	Amendment No. 1 to the Surface Operating Agreement dated October 10, 2006 entered into on June 17, 2008 by and between BreitBurn Energy Company L.P. and its predecessor BreitBurn Energy Corporation and Breitburn Operating LP (incorporated herein by reference to Exhibit 10.7 to the Current Report on Form 8-K (File No. 001-33055) filed on June 23, 2008).
10.20	Indemnity Agreement between Breitburn Energy Partners LP, Breitburn GP LLC and Halbert S. Washburn, together with a schedule identifying other substantially identical agreements between Breitburn Energy Partners LP, Breitburn GP LLC and each of its executive officers and non-employee directors identified on the schedule (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on November 4, 2009).
10.21	Third Amended and Restated Employment Agreement dated December 30, 2010 among Breitburn Management Company LLC, Breitburn GP LLC, Breitburn Energy Partners LP and Halbert S. Washburn (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on January 6, 2011).
10.22	Amended and Restated Employment Agreement dated December 30, 2010 among Breitburn Management Company LLC, Breitburn GP LLC, Breitburn Energy Partners LP and Mark L. Pease (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K (File No. 001-33055) filed on January 6, 2011).
10.23	Second Amended and Restated Employment Agreement dated December 30, 2010 among Breitburn Management Company LLC, Breitburn GP LLC, Breitburn Energy Partners LP and James G. Jackson (incorporated herein by reference to Exhibit 10.4 to the Current Report on Form 8-K (File No. 001-33055) filed on January 6, 2011).
10.24	Amended and Restated Employment Agreement dated December 30, 2010 among Breitburn Management Company LLC, Breitburn GP LLC, Breitburn Energy Partners LP and Gregory C. Brown (incorporated herein by reference to Exhibit 10.5 to the Current Report on Form 8-K (File No. 001-33055) filed on January 6, 2011).
10.25†	Retirement Agreement, dated as of November 30, 2012, among Breitburn Energy Partners LP, Breitburn GP LLC and Randall H. Breitenbach (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on December 6, 2012).
10.26†	First Amended and Restated Breitburn Energy Partners LP 2006 Long-Term Incentive Plan effective as of October 29, 2009 (incorporated herein by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009 (File No. 001-33055) filed on November 6, 2009).
10.27†	First Amendment to the First Amended and Restated Breitburn Energy Partners LP 2006 Long Term Incentive Plan (incorporated herein by reference to Exhibit 10.2 to the Form S-8 Registration Statement (File No. 333-181526) filed on May 18, 2012).
10.28†	Second Amendment to First Amended and Restated BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan effective as of June 18, 2015 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on June 18, 2015).
10.29†	Form of First Amendment to Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreements (2014 awards).
10.30†	Omnibus First Amendment to the Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreements, dated as of November 30, 2012, among Breitburn Energy Partners LP, Breitburn GP LLC and Randall H. Breitenbach (incorporated herein by reference to Exhibit 10.2 to the Current Report on form 8-K (File No. 001-33055) filed on December 6, 2012).

10.31†	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Deferred Payment Award) for 2013 grants (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 (File No. 001-33055) filed on May 3, 2013).
10.32†	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreement (Employment Agreement Form) for 2014 grants (incorporated herein by reference to Exhibit 10.47 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2013 (File No. 001-33055) filed on February 28, 2014).
10.33†	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Employment Agreement Form) for 2014 grants (incorporated herein by reference to Exhibit 10.48 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2013 (File No. 001-33055) filed on February 28, 2014).
10.34†	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Director Form) for 2014 grants (incorporated herein by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2013 (File No. 001-33055) filed on February 28, 2014).
10.35†	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Deferred Payment Award) for 2014 grants (incorporated herein by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2013 (File No. 001-33055) filed on February 28, 2014).
10.36†	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Employment Agreement Form) for 2015 grants.
10.37†	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Non-Employment Agreement Form) for 2015 grants.
10.38†	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Director Form) for 2015 grants.
10.39†*	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Stock-Settled) (Employment Agreement Form) for 2016 grants.
10.40†*	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Stock-Settled) (Non-Employment Agreement Form) for 2016 grants.
10.41†*	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Stock-Settled) (Director Form) for 2016 grants.
10.42†*	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Cash-Settled) (Employment Agreement Form) for 2016 grants.
10.43†*	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Cash-Settled) (Non-Employment Agreement Form) for 2016 grants.
10.44†*	Form of Breitburn Energy Partners LP 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Cash-Settled) (Director Form) for 2016 grants.
10.45†*	Breitburn Energy Partners LP Incentive Bonus Award Agreement for 2016 grants.
12.1*	Computation of Ratio of Earnings to Fixed Charges.
14.1	Code of Ethics for Chief Executive Officers and Senior Officers (as amended and restated on February 28, 2007) (incorporated herein by reference to Exhibit 14.1 to the Current Report on Form 8-K filed on March 5, 2007).
21.1*	List of Subsidiaries of Breitburn Energy Partners LP.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Cawley, Gillespie & Associates, Inc.
31.1*	Certification of Registrant's Chief Executive Officer pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934 and Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Registrant's Chief Financial Officer pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934 and Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Registrant's Chief Executive Officer pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934 and 18 U.S.C. Section 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002.

32.2**	Certification of Registrant's Chief Financial Officer pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934 and 18 U.S.C. Section 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Netherland, Sewell & Associates, Inc. reserve report.
99.2*	Cawley, Gillespie & Associates, Inc. reserve report.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

*	Filed herewith.
**	Furnished herewith.
†	Management contract or compensatory plan or arrangement.

BREITBURN
ENERGY PARTNERS LP

BREITBURN ENERGY PARTNERS LP
707 Wilshire Boulevard
Suite 4600
Los Angeles, California 90017

March 7, 2016

TO THE LIMITED PARTNERS OF BREITBURN ENERGY PARTNERS LP:

We cordially invite you to the Annual Meeting of Limited Partners (the "Annual Meeting") of Breitburn Energy Partners LP (the "Partnership"). The Annual Meeting will be held on April 28, 2016, at 9:00 a.m., Pacific Daylight Time, at City Club Los Angeles, Harbor Room, 555 South Flower Street, 51st Floor, Los Angeles, California 90071.

The following pages contain the formal Notice of the Annual Meeting and the Proxy Statement. At the Annual Meeting, you will be asked to vote on (1) the election of three directors, Randall H. Breitenbach, Halbert S. Washburn and Charles S. Weiss, to the Board of Directors of Breitburn GP LLC, the general partner of the Partnership (the "General Partner"), to serve for a three-year term that will expire in 2019 at the 2019 annual meeting of limited partners ("Class II Directors"), or until their successors are duly elected and qualified; and (2) the ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the year ending December 31, 2016. You will also be asked to transact such other business as may properly come before the Annual Meeting, or any postponements or adjournments thereof.

Our General Partner's Board of Directors unanimously recommends that you vote "**FOR ALL**" of the Class II Directors nominated for reelection and "**FOR**" the ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm.

To be certain that your units are voted at the Annual Meeting, whether or not you plan to attend in person, you should vote your units as soon as possible. Your vote is important. You may vote by telephone, Internet or mail. To vote by telephone, call 1-800-690-6903 using a touch-tone phone to transmit your voting instructions up until 11:59 p.m. (EDT) the day before the Annual Meeting date. Your proxy card has a control number that you must have to receive access to vote. Have your proxy card in hand when you call and follow the instructions. To vote electronically, access *http://www.proxyvote.com* over the Internet to transmit your voting instructions and for electronic delivery of information up until 11:59 p.m. (EDT) the day before the Annual Meeting date. Your proxy card has a control number that you must have to receive access to vote. Have your proxy card in hand when you access the website and follow the instructions to obtain your records and to create an electronic voting instruction form. To vote by mail, mark, sign and date your proxy card and return it in the postage-paid envelope we have provided or return it to Vote Processing, c/o Broadridge Financial Solutions, 51 Mercedes Way, Edgewood, NY 11717.

At the Annual Meeting, our management team will review our performance during the past year and discuss our plans for the future. An opportunity will be provided for questions by the unitholders. You will have an additional opportunity to meet with management. I hope you will be able to join us.

Sincerely,

John R. Butler, Jr.
Chairman of the Board of
Breitburn GP LLC, general partner of
Breitburn Energy Partners LP

BREITBURN ENERGY PARTNERS LP
707 Wilshire Boulevard
Suite 4600
Los Angeles, California 90017

NOTICE OF ANNUAL MEETING OF LIMITED PARTNERS
March 7, 2016

TO THE LIMITED PARTNERS OF BREITBURN ENERGY PARTNERS LP:

You are invited to the Annual Meeting of Limited Partners (the "Annual Meeting") of Breitburn Energy Partners LP (the "Partnership"), which will be held at 9:00 a.m., Pacific Daylight Time, on April 28, 2016, at City Club Los Angeles, Harbor Room, 555 South Flower Street, 51st Floor, Los Angeles, California 90071, for the following purposes:

1. To elect three directors, Randall H. Breitenbach, Halbert S. Washburn and Charles S. Weiss, to the Board of Directors of Breitburn GP LLC, the general partner of Breitburn Energy Partners LP (the "General Partner"), to serve for a three-year term that will expire in 2019 at the 2019 annual meeting of limited partners ("Class II Directors"), or until their successors are duly elected and qualified;

2. To ratify the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the year ending December 31, 2016; and

3. To transact such other business as may properly come before the Annual Meeting, or any postponements or adjournments thereof.

The Board of Directors of our General Partner has fixed the close of business on March 4, 2016, as the record date for the determination of unitholders entitled to notice of, and to vote at, the Annual Meeting. Only unitholders of record as of the close of business on such date are entitled to notice of, and to vote at, the Annual Meeting.

We encourage you to take part in the affairs of the Partnership either by voting in person, by telephone, by Internet or by executing and returning the enclosed proxy.

By Order of the Board of Directors of the General Partner,

Gregory C. Brown
Executive Vice President, General Counsel and
Chief Administrative Officer of Breitburn GP LLC,
general partner of Breitburn Energy Partners LP

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF
PROXY MATERIALS FOR THE ANNUAL MEETING OF LIMITED PARTNERS
TO BE HELD ON APRIL 28, 2016

The Notice of Annual Meeting of Limited Partners, the Proxy Statement for the Annual Meeting, a form of proxy, and the 2015 Annual Report to Unitholders, which includes the Annual Report on Form 10-K for the year ended December 31, 2015, are available at *http://www.proxyvote.com*.

BREITBURN
ENERGY PARTNERS LP

BREITBURN ENERGY PARTNERS LP
707 Wilshire Boulevard
Suite 4600
Los Angeles, California 90017

ANNUAL MEETING OF LIMITED PARTNERS

The Annual Meeting of Limited Partners of Breitburn Energy Partners LP will be held at
City Club Los Angeles
Harbor Room
555 South Flower Street, 51st Floor
Los Angeles, California 90071
on April 28, 2016, at 9:00 a.m., Pacific Daylight Time

YOUR VOTE IS IMPORTANT!

Whether or not you expect to attend the Annual Meeting in person, we urge you to vote your units by phone, via the Internet, or by signing, dating, and returning the enclosed proxy card at your earliest convenience. This will ensure the presence of a quorum at the Annual Meeting. Submitting your proxy now will not prevent you from voting your units at the Annual Meeting if you desire to do so, as your vote by proxy is revocable at your option.

Voting by the **Internet** or **telephone** is fast, convenient, and your vote is immediately confirmed and tabulated. Most important, by using the Internet or telephone, you help us reduce our postage and proxy tabulation costs. If you prefer, you can vote by mail by returning the enclosed proxy card in the enclosed addressed, prepaid envelope.

VOTE BY INTERNET

http://www.proxyvote.com/
24 hours a day / 7 days a week

INSTRUCTIONS:

Read the accompanying proxy statement and proxy card.
Go to the following website:
http://www.proxyvote.com

Use the Internet to transmit your voting instructions and for electronic delivery of information up until 11:59 p.m. (EDT) the day before the Annual Meeting date. Have your proxy card in hand when you access the website and follow the instructions to obtain your records and to create an electronic voting instruction form.

VOTE BY TELEPHONE

1-800-690-6903 via touch-tone phone
toll-free 24 hours a day / 7 days a week

INSTRUCTIONS:

Read the accompanying proxy statement and proxy card.
Call the toll-free 800 number above.

Use any touch-tone telephone to transmit your voting instructions up until 11:59 p.m. (EDT) the day before the Annual Meeting date. Have your proxy card in hand when you call and follow the instructions.

PLEASE DO NOT RETURN THE ENCLOSED PAPER PROXY IF YOU ARE VOTING OVER THE INTERNET OR BY TELEPHONE.

BREITBURN ENERGY PARTNERS LP
707 Wilshire Boulevard
Suite 4600
Los Angeles, California 90017

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BREITBURN ENERGY PARTNERS LP
707 Wilshire Boulevard
Suite 4600
Los Angeles, California 90017

GENERAL

References in this proxy statement to “the Partnership,” “we,” “our,” “us” or like terms refer to Breitburn Energy Partners LP and its subsidiaries. References in this proxy statement to “PCEC” or the “Predecessor” refer to Pacific Coast Energy Company LP, formerly named BreitBurn Energy Company L.P., our predecessor, and its predecessors and subsidiaries. References in this proxy statement to the “General Partner” refer to Breitburn GP LLC, our general partner and our wholly owned subsidiary. References in this proxy statement to the “Board” refer to the Board of Directors of the General Partner. References in this proxy statement to “The Strand Energy Company” refer to a corporation formerly named BreitBurn Energy Corporation and 74% owned by Halbert S. Washburn and Randall H. Breitenbach, the Chief Executive Officer and a member of the Board of Directors and the Vice Chairman of the Board of Directors of the General Partner, respectively. References in this proxy statement to “Breitburn Management” refer to Breitburn Management Company LLC, our administrative manager and wholly owned subsidiary. References in this proxy statement to the “Partnership Agreement” refer to our Third Amended and Restated Agreement of Limited Partnership, dated as of April 8, 2015. References in this proxy statement to “common units” refer to common units representing limited partner interests in the Partnership. References in this proxy statement to “Series B units” refer to the Partnership’s Series B Perpetual Convertible Preferred Units. References in this proxy statement to “units” refers to the common units and Series B units. References in this proxy statement to “unitholders” and “limited partners” refer to limited partners of the Partnership owning our common units and/or Series B units.

This proxy statement contains information related to our Annual Meeting of Limited Partners to be held on April 28, 2016 (the “Annual Meeting”), beginning at 9:00 a.m., Pacific Daylight Time, at City Club Los Angeles, Harbor Room, 51st Floor, Los Angeles, California 90071, and at any postponements or adjournments thereof. This proxy statement and the accompanying proxy card, which are accompanied by our annual report to unitholders, will first be mailed to unitholders on or about March 18, 2016. Our annual report to unitholders includes our Annual Report on Form 10-K for the year ended December 31, 2015 (the “2015 Annual Report”). Unitholders are referred to the 2015 Annual Report for financial and other information about our business. The 2015 Annual Report is not incorporated by reference into this proxy statement and is not deemed to be a part of this proxy statement.

ABOUT THE ANNUAL MEETING

Who sent me this proxy statement?

The Board sent you this proxy statement and proxy card. We will pay for the solicitation of your proxy. In addition to this solicitation by mail, proxies may be solicited by the directors, officers and other employees of our General Partner and our affiliates by telephone, Internet, facsimile, in person or otherwise. These people will not receive any additional compensation for assisting in the solicitation. We may also request brokerage firms, nominees, custodians and fiduciaries to forward proxy materials to the beneficial owners of our units. We will reimburse those people and our transfer agent for their reasonable out-of-pocket expenses in forwarding such material. We will also bear the entire cost of the preparation, assembly, printing and mailing of this proxy statement, the proxy card, and any additional information furnished to unitholders. We have retained Broadridge Financial Solutions, Inc., a proxy soliciting firm, to assist in the solicitation of proxies, provide voting and tabulation services and serve as inspector of election at the Annual Meeting for an estimated cost of $183,000.

Why did I receive this proxy statement and proxy card?

You received this proxy statement and proxy card from us because you owned our common units or Series B units as of the record date, March 4, 2016, and, as a result, you are entitled to elect directors to serve on the Board and to vote on the other proposals to be voted on at the Annual Meeting. This proxy statement contains important information for you to consider when deciding whether and/or how to vote on the various proposals to be voted on at the Annual Meeting, including the election of directors and ratification of the selection of our independent registered public accounting firm. Please read this proxy statement carefully.

What is a proxy?

A proxy is your legal designation of another person to vote the units that you own. That other person is also called a proxy. If you designate someone as your proxy in a written document, that document is also called a proxy or a proxy card. Halbert S. Washburn and Gregory C. Brown, or either of them, each with power of substitution, have been appointed by the Board as proxies for the Annual Meeting.

What is a proxy statement?

A proxy statement is a document that the regulations of the Securities and Exchange Commission ("SEC") require us to give you when we ask you to sign a proxy card designating proxies to vote on your behalf. The proxy statement includes information about the proposals to be considered at the Annual Meeting and other required disclosures, including information about the Board.

What does it mean if I receive more than one proxy card?

Your receipt of more than one proxy card means that you have multiple accounts with our transfer agent and/or with a brokerage firm, bank or other nominee. If voting by mail, please sign and return all proxy cards to ensure that all of your units are voted. Each proxy card represents a discrete number of units and it is the only means by which those particular units may be voted by proxy.

What is the purpose of the Annual Meeting?

At the Annual Meeting, our unitholders will act upon the matters outlined in the Notice of Annual Meeting, including the election of the Class II Directors and the ratification of the appointment of our independent registered public accounting firm, as well as such other business as may properly come before the Annual Meeting, or any postponements or adjournments thereof.

What is the difference between a unitholder of record and a unitholder who holds units in “street name”?

Most of our unitholders hold their units through a brokerage firm, bank or other nominee rather than directly in their own name. As summarized below, there are some distinctions between units held of record and those held beneficially through a brokerage account, bank or other nominee.

- *Unitholder of Record.* If your units are registered directly in your name with our transfer agent, you are considered, with respect to those units, the “unitholder of record,” and these proxy materials are being sent directly to you by us. As the unitholder of record, you have the right to grant your voting proxy directly or to vote in person at the Annual Meeting. We have enclosed a proxy card for you to use.
- *Street Name.* If your units are held in a brokerage account or by a bank or other nominee, you are considered the beneficial owner of common units held in “street name,” and these proxy materials are being forwarded to you by your broker or nominee, which is considered, with respect to those units, the unitholder of record. As the beneficial owner, you have the right to direct your broker how to vote and are also invited to attend the Annual Meeting. However, since you are not the unitholder of record, you may not vote these units in person at the Annual Meeting unless you obtain a signed proxy from the record holder giving you the right to vote the units. Your broker or nominee has enclosed or provided a voting instruction card for you to use in directing the broker or nominee how to vote your units.

What is the record date and what does it mean?

The record date established by the Board for the Annual Meeting is March 4, 2016. Unitholders of record at the close of business on the record date are entitled to:

- receive notice of the Annual Meeting; and
- vote at the Annual Meeting and any adjournments or postponements of the Annual Meeting.

Who is entitled to vote at the Annual Meeting?

Each of our common units and Series B units Outstanding (as defined in the Partnership Agreement) as of the close of business on March 4, 2016, the record date, is entitled to one vote per unit at the Annual Meeting, subject to certain exceptions as described below under the heading “Voting Requirements for the Annual Meeting.”

As of the record date, 213,679,116 of our common units and 49,375,001 of our Series B units were Outstanding, all of which are entitled to vote at the Annual Meeting.

Who can attend the Annual Meeting?

All unitholders as of the record date, or their duly appointed proxies, may attend the Annual Meeting.

Units held directly in your name as the unitholder of record can be voted in person at the Annual Meeting. Units held in street name (for example, at your brokerage account) may be voted in person by you only if you obtain a signed proxy from the record holder giving you the right to vote the units. In addition, if you plan to vote in person at the Annual Meeting, please bring the enclosed proxy card or proof of identification.

Even if you currently plan to attend the Annual Meeting in person, we recommend that you also submit your proxy as described below so that your vote will be counted if you later decide not to attend the Annual Meeting.

What constitutes a quorum?

The holders of a majority of the Outstanding (as defined in the Partnership Agreement) common units and Series B units on the record date, represented in person or by proxy, will constitute a quorum, subject to certain exceptions as described below under the heading “Voting Requirements for the Annual Meeting.” As of March 4, 2016, there were 213,679,116 common units and 49,375,001 Series B units Outstanding. Consequently, holders of at least 131,527,059 units must be present either in person or by proxy to establish a quorum for the Annual Meeting. Proxies received but marked as abstentions and broker non-votes will be included in the number of common units considered to be present at the Annual Meeting for purposes of establishing a quorum.

How do I vote?

If you complete and properly sign the accompanying proxy card and return it to us, or properly transmit your vote by telephone or electronically as described below, your units will be voted as you direct. If you are a unitholder of record and attend the Annual Meeting, you may deliver your completed proxy card in person or vote by ballot using a form provided at the Annual Meeting. Street name unitholders who wish to vote at the Annual Meeting will need to obtain a proxy form from the institution that holds their units. Even if you plan to attend the Annual Meeting, your plans may change; thus, we recommend you complete, sign and return your proxy card or vote by telephone or electronically in advance of the Annual Meeting.

You may vote by telephone by calling 1-800-690-6903 using a touch-tone phone to transmit your voting instructions up until 11:59 p.m. (EDT) the day before the Annual Meeting date. Your proxy card has a control number that you must have to receive access to vote. Have your proxy card in hand when you call and follow the instructions. To vote electronically, access *http://www.proxyvote.com* over the Internet to transmit your voting instructions and for electronic delivery of information up until 11:59 p.m. (EDT) the day before the Annual Meeting date. Your proxy card has a control number that you must have to receive access to vote. Have your proxy card in hand when you access the website and follow the instructions to obtain your records and to create an electronic voting instruction form. To vote by mail, mark, sign and date your proxy card and return it in the postage-paid envelope we have provided or return it to Vote Processing, c/o Broadridge Financial Solutions, 51 Mercedes Way, Edgewood, NY 11717.

May I vote confidentially?

Yes. We treat all unitholder meeting proxies and ballots confidentially if the unitholder has requested confidentiality on the proxy or ballot.

Can I change my vote after I return my proxy card?

Yes. If you are a unitholder of record, you may revoke a previously submitted proxy at any time before the polls close at the Annual Meeting by:

- timely submitting a proxy with new voting instructions using the telephone or Internet voting system;
- timely delivering a valid, later-dated executed proxy card;
- giving written notice of revocation to Breitburn Energy Partners LP, Attention: Investor Relations, 707 Wilshire Boulevard, Suite 4600, Los Angeles, California 90017, no later than later than 11:59 p.m. (EDT) on April 27, 2016; or
- attending the Annual Meeting and voting your common units in person; however, attending the Annual Meeting will not by itself have the effect of revoking a previously submitted proxy.

If you are a street name unitholder, you must follow the instructions on revoking your proxy, if any, provided by your bank or broker.

What are the recommendations of the Board?

Unless you give other instructions on your proxy card, the persons named as proxy holders on the proxy card will vote in accordance with the recommendations of the Board. The recommendations of the Board are set forth together with the description of each item in this proxy statement. In summary, the Board recommends a vote:

- "**FOR ALL**" of the Class II Directors nominated for reelection to the Board; and
- "**FOR**" the ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the year ending December 31, 2016.

With respect to any other matter that properly comes before the Annual Meeting, the proxy holders will vote as recommended by the Board or, if no recommendation is given, at their own discretion.

What are "abstentions" and "broker non-votes" and how are these votes treated?

An "abstention" occurs when a unitholder is present at the Annual Meeting but fails to vote or voluntarily withholds his or her vote for any of the matters upon which the unitholders are voting. Abstentions are considered "present" and are included in the quorum calculations.

If you hold your units in street name, you will receive instructions from your brokers or other nominees describing how to vote your units yourself or, in the alternative, how to direct your brokers or other nominees to vote your units held in street name. If you do not vote your units held in street name yourself and if you do not instruct your brokers or nominees how to vote your units, they may vote your units as they decide as to each matter for which they have discretionary authority under stock exchange rules. The election of directors (Proposal 1) is a non-discretionary matter for which brokers and other nominees do not have discretionary authority to vote unless they receive timely instructions from you. As such, for Proposal 1 to be voted on at the Annual Meeting, you must provide timely instructions on how the broker or other nominee should vote your units. When a broker or other nominee does not have discretion to vote on a particular matter, you have not given timely instructions on how the broker or other nominee should vote your units, and the broker or other nominee indicates it does not have authority to vote such units on its proxy, a "broker non-vote" results. Although any broker non-vote would be counted as present at the meeting for purposes of determining a quorum, it would be treated as not entitled to vote with respect to non-discretionary matters, and, as such, broker non-votes will not be counted as a vote "**FOR**" or "**AGAINST**" the election of directors. The ratification of the appointment of our independent registered public accounting firm as our independent auditors for the year ending December 31, 2016 (Proposal 2) is a discretionary matter on which brokers and other nominees may vote in the absence of timely instructions from you.

What are my voting choices when voting for Class II Director nominees and what vote is needed to elect the nominees?

In the vote on the election of the Class II Director nominees, you may:

- vote "**FOR ALL**" as to all nominees;
- vote "**WITHHOLD ALL**" as to all nominees; or
- vote "**FOR ALL EXCEPT**" as to specific nominees.

The Board recommends a vote "**FOR ALL**" of the nominees.

Please see "Voting Requirements for the Annual Meeting" for an explanation of the vote needed to elect the Class II Directors.

What are my voting choices when voting on the ratification of the Audit Committee's appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the year ending December 31, 2016, and what vote is needed to ratify their appointment?

In the vote on the ratification of the appointment of PricewaterhouseCoopers LLP, you may:

- vote "**FOR**" the ratification;
- vote "**AGAINST**" the ratification; or
- vote "**ABSTAIN**" on the ratification.

The Board recommends a vote "**FOR**" the ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the year ending December 31, 2016.

Please see "Voting Requirements for the Annual Meeting" for an explanation of the vote needed to approve this proposal.

What if I do not specify a choice for a matter when returning my proxy?

You should specify your choice for each matter on the enclosed proxy. If you sign and return your proxy but do not give specific instructions, your proxy will be voted "**FOR ALL**" of the Class II Director nominees and "**FOR**" the ratification of the appointment of Pricewaterhouse Coopers LLP as our independent registered public accounting firm for the year ending December 31, 2016.

Do I have dissenters' rights of appraisal?

We are a limited partnership under the laws of the State of Delaware, including the Delaware Revised Uniform Limited Partnership Act. Under those laws, dissenters' rights are not available to our unitholders with respect to the matters to be voted upon at the Annual Meeting.

Who counts the votes?

Broadridge Financial Solutions will tabulate the votes and will act as the independent inspector of election.

Whom should I contact with questions?

If you have any questions about this proxy statement or the Annual Meeting, please contact our Investor Relations Department in writing at 707 Wilshire Boulevard, Suite 4600, Los Angeles, California 90017 or by telephone at (213) 225-5900.

Where may I obtain additional information about Breitburn Energy Partners LP?

We refer you to our 2015 Annual Report for additional information about us. Our 2015 Annual Report is included with your proxy materials. You may receive additional copies of our 2015 Annual Report at no charge through the Investor Relations section of our website at *http://www.breitburn.com*. This proxy statement, a form of proxy and our 2015 Annual Report are also available at *http://www.proxyvote.com*. You may receive additional copies of our 2015 Annual Report or proxy statement at no charge, or request to receive any additional information or directions to the Annual Meeting to be able to vote in person, by contacting our Investor Relations Department in writing at 707 Wilshire Boulevard, Suite 4600, Los Angeles, California 90017 or by telephone at (213) 225-5900. In order to facilitate timely delivery of such additional proxy materials, such a request must be made by April 14, 2016, as we are unable to guarantee the timely delivery of additional proxy materials for requests made after this date.

How do I get to the Annual Meeting?

The Annual Meeting will be held at City Club Los Angeles, Harbor Room, 555 South Flower Street, 51st Floor, Los Angeles, California 90071, which is located in downtown Los Angeles. The City Club is bounded on the west by S. Figueroa Street, on the east by S. Flower Street, on the north by W. 5th Street and on the south by W. 6th Street.

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE ANNUAL MEETING OF LIMITED PARTNERS TO BE HELD ON APRIL 28, 2016

The Notice of Annual Meeting of Limited Partners, the Proxy Statement for the Annual Meeting, including a form of proxy, and the 2015 Annual Report to Unitholders, which includes the Annual Report on Form 10-K for the year ended December 31, 2015, are available at *http://www.proxyvote.com.*

VOTING REQUIREMENTS FOR THE ANNUAL MEETING

Right to Vote and Related Matters

Only those record holders of our common units and Series B units on March 4, 2016, the record date for the Annual Meeting (subject to the limitations contained in the definition of "Outstanding" and in Section 13.4(b) in the Partnership Agreement), are entitled to notice of, and to vote at, the Annual Meeting, or to act with respect to matters as to which the holders of the Outstanding common units and Series B units have the right to vote or to act. All references in this proxy statement to votes of, or other acts that may be taken by, the Outstanding common units and Series B units are deemed to be references to the votes or acts of the record holders of such Outstanding common units and Series B units. As of the record date, 213,679,116 of our common units and 49,375,001 of our Series B units were Outstanding, all of which are entitled to vote at the Annual Meeting.

Pursuant to the Partnership Agreement, each holder of our Outstanding common units and Series B units as of the close of business on the record date is entitled to one vote per unit at the Annual Meeting, subject to the exceptions described below. As defined in the Partnership Agreement, "Outstanding" means, with respect to Partnership Securities (as defined in the Partnership Agreement), all Partnership Securities that are issued by the Partnership and reflected as outstanding on the Partnership's books and records as of the date of determination; provided, however, that if at any time any person or group (other than our General Partner or its affiliates) beneficially owns 20% or more of the Outstanding Partnership Securities of any class then Outstanding, all Partnership Securities owned by such person or group cannot be voted on any matter, except with respect to the election of directors to the Board, and are not considered to be Outstanding when sending notices of a meeting of limited partners to vote on any matter (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement, except that units so owned are considered to be Outstanding for purposes of Section 11.1(b)(iv) of the Partnership Agreement relating to the voluntary withdrawal of our General Partner (such units are not, however, treated as a separate class of Partnership Securities for purposes of the Partnership Agreement). However, the foregoing limitation does not apply to (1) any person or group who acquired 20% or more of the Outstanding Partnership Securities of any class then Outstanding directly from our General Partner or its affiliates, (2) any person or group who acquired 20% or more of the Outstanding Partnership Securities of any class then Outstanding directly or indirectly from a person or group described in clause (1) provided that our General Partner has notified such person or group in writing that such limitation does not apply, (3) any person or group who acquired 20% or more of any Partnership Securities issued by the Partnership with the prior approval of the Board or (4) any person or group who acquires 20% or more of the Series B units, if and only if such person does not, at or after such acquisition, beneficially own or acquire 20% of more of the voting power of the common units.

With respect to the election of directors to the Board, (1) we and our General Partner will not be entitled to vote common units that are otherwise entitled to vote at any meeting of the limited partners, and (2) if at any time any person or group beneficially owns 20% or more of the Outstanding Partnership Securities of any class then Outstanding, then all Partnership Securities owned by such person or group in excess of 20% of the Outstanding Partnership Securities of the applicable class may not be voted, and in each case, the foregoing common units will not be counted when calculating the required votes for such matter and will not be deemed to be Outstanding for purposes of determining a quorum for such meeting. Such common units will not be treated as a separate class of Partnership Securities for purposes of the Partnership Agreement.

With respect to units that are held for a person's account by another person (such as a broker, dealer, bank, trust company or clearing corporation, or an agent of any of the foregoing) in whose name such units are registered, such other person must, in exercising the voting rights in respect of such units on any matter, and unless the arrangement between such persons provides otherwise, vote such units in favor of, and at the direction of, the person who is the beneficial owner, and the Partnership is entitled to assume it is so acting without further inquiry.

Quorum

Subject to the 20% limitations described above, the holders of a combined majority of the Outstanding common units and Series B units on the record date, represented in person or by proxy, will constitute a quorum at the Annual Meeting, unless any such action by the limited partners requires approval by holders of a greater percentage of such units, in which case the quorum will be such greater percentage. Proxies received but marked as abstentions and broker non-votes will be included in the number of units considered to be present at the Annual Meeting. The limited partners present at a duly called or held meeting at which a quorum is present may continue to transact business until adjournment, notwithstanding the withdrawal of enough limited partners to leave less than a quorum, if any action taken (other than adjournment) is approved by the required percentage of Outstanding common units and Series B units specified in the Partnership Agreement (including Outstanding common units deemed owned by our General Partner, if any). In the absence of a quorum, the Annual Meeting may be adjourned from time to time by the affirmative vote of holders of at least a majority of the Outstanding common units and Series B units entitled to vote at the Annual Meeting (including Outstanding common units deemed owned by our General Partner, if any) represented either in person or by proxy, but no other business may be transacted, except as otherwise provided in the Partnership Agreement.

Required Vote for the Election of Class II Directors

Pursuant to the Partnership Agreement, the directors of the Board of our General Partner are elected by a plurality of the votes cast by the unitholders entitled to vote at the Annual Meeting. This means that the three Class II Director nominees receiving the highest number of affirmative votes at the Annual Meeting will be elected. Withholding votes, abstentions and broker non-votes will be counted for purposes of determining the presence or absence of a quorum but otherwise will have no effect on the election of a director nominee. You may not cumulate your votes in the election of directors.

Required Vote for the Ratification of the Audit Committee's Appointment of PricewaterhouseCoopers LLP as Our Independent Registered Public Accounting Firm for the Year Ending December 31, 2016

Pursuant to the Partnership Agreement, the proposal to ratify the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the year ending December 31, 2016 will require approval by the holders of a majority of the Outstanding common units and Series B units entitled to vote and present in person or by proxy at the Annual Meeting. Abstentions will have the same effect as votes "**AGAINST**" the proposal. Because brokers and other nominees will have discretion to vote common units without the direction of their clients with respect to this proposal, there will not be any broker non-votes with respect to this proposal.

PROPOSALS PRESENTED FOR UNITHOLDER VOTE

PROPOSAL 1:

ELECTION OF THREE CLASS II DIRECTORS TO SERVE A THREE-YEAR TERM UNTIL THE 2019 ANNUAL MEETING

The Board is comprised of eight directors. The Board has been divided into three classes: Class I, Class II and Class III. The directors designated in the Fourth Amended and Restated Limited Liability Company Agreement of our General Partner (as amended, the "Limited Liability Company Agreement") to Class II are serving a term that expires at the Annual Meeting. The directors designated to Class III are serving a term that expires at the annual meeting to be held in 2017. The directors designated to Class I are serving for a term that expires at the annual meeting to be held in 2018. Successors to the class of directors whose term expires at an annual meeting will be elected for a three-year term, or until their successors are duly elected and qualified.

The three Class II Board members whose terms expire at the Annual Meeting are Randall H. Breitenbach, Halbert S. Washburn and Charles S. Weiss. The Board recommends the approval of the election of Messrs. Breitenbach, Washburn and Weiss to serve as Class II Directors for a term of three years, until the Partnership's annual meeting to be held in 2019, or until their successors are duly elected and qualified. Certain individual qualifications and skills of our directors that contribute to the Board's effectiveness as a whole are described below in each director's biographical information under the heading "Board of Directors and Executive Officers."

Unless otherwise indicated on the proxy, the persons named as proxies in the enclosed proxy will vote "**FOR ALL**" of the nominees listed above. Although we have no reason to believe that any of the nominees will be unable to serve if elected, should any of the nominees become unable to serve prior to the Annual Meeting, the proxies will be voted for the election of such other persons as may be nominated by the Board. Unitholders may not cumulate their votes in the election of directors.

THE BOARD UNANIMOUSLY RECOMMENDS A VOTE "FOR ALL" OF THE CLASS II DIRECTOR NOMINEES.

PROPOSAL 2:

RATIFICATION OF APPOINTMENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

General

The Audit Committee of the Board has appointed PricewaterhouseCoopers LLP as our independent registered public accounting firm to examine and report to unitholders on the consolidated financial statements of our Partnership and its subsidiaries for the year ending December 31, 2016. PricewaterhouseCoopers LLP has served as our independent registered public accounting firm since 2006.

Representatives of PricewaterhouseCoopers LLP are expected to be present at the Annual Meeting. They also will be available to respond to appropriate questions and inquiries from unitholders.

Unitholder ratification of the selection of PricewaterhouseCoopers LLP as the Partnership's independent registered public accounting firm is not required by the Partnership Agreement or otherwise. We are doing so because we believe it is a matter of good corporate practice to do so. If the unitholders fail to ratify the selection, the Audit Committee will reconsider the retention of that firm, but may retain such independent auditor. Even if the selection is ratified, the Audit Committee, in its discretion, may direct the appointment of a different independent registered public accounting firm at any time during the year if the Audit Committee determines that such a change would be in the best interests of the Partnership and its unitholders.

THE BOARD UNANIMOUSLY RECOMMENDS A VOTE "FOR" THE RATIFICATION OF PRICEWATERHOUSECOOPERS LLP AS OUR INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR THE YEAR ENDING DECEMBER 31, 2016.

Fees Paid to Independent Registered Public Accounting Firm

For the years ended December 31, 2015 and 2014, consolidated fees billed by our independent registered public accounting firm, PricewaterhouseCoopers LLP, to the Partnership were as follows (in thousands):

	Year Ended December 31,	
Thousands of dollars	**2015**	**2014**
Audit fees (1)	$ 2,665	$ 3,117
Tax fees (2)	1,228	629
Other fees (3)	4	2
Total	$ 3,897	$ 3,748

(1) Audit fees represent fees provided for the integrated audits of our annual financial statements, review of our quarterly financial statements. They also include work performed as part of our registration statements for debt and equity offerings and in connection with mergers and acquisitions, which totaled approximately $367,500 and $1,265,000, respectively, for the years ended December 31, 2015 and December 31, 2014.

(2) Tax fees relate to tax preparation as well as the preparation of Forms K-1 for our unitholders, including Forms K-1 for the former unitholders of QR Energy, LP for approximately $569,000.

(3) Other fees relate to accounting software fees.

Audit Committee Pre-Approval Policies and Procedures

The Audit Committee Charter requires the Audit Committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. Consistent with the Audit Committee Charter, all services reported in the audit, audit-related, tax and all other fees categories under "Fees Paid to Independent Registered Public Accounting Firm" above were pre-approved by the Audit Committee.

BOARD OF DIRECTORS AND EXECUTIVE OFFICERS

As with most publicly traded limited partnerships, we do not have a board of directors or employees, but instead our General Partner manages our operations and activities on our behalf. The following table shows information for the executive officers and the members of the Board of our General Partner. Executive officers are not appointed for a specific term and instead serve at the discretion of the Board in their respective offices until they resign, their employment is terminated or they are re-appointed by the Board. Directors generally are elected to three-year terms, or until their successors are duly elected and qualified. The term of the Class II Directors will expire at the Annual Meeting. The directors designated to Class III are serving for a term that expires at the annual meeting to be held in 2017. The term of the Class I Directors will expire at the annual meeting to be held in 2018. Successors to the class of directors whose term expires at an annual meeting will be elected for a three-year term, or until their successors are duly elected and qualified.

Name	Age	Position with our General Partner
Halbert S. Washburn *	56	Chief Executive Officer and Director
Mark L. Pease	59	President and Chief Operating Officer
James G. Jackson	51	Executive Vice President and Chief Financial Officer
Gregory C. Brown	64	Executive Vice President, General Counsel and Chief Administrative Officer
W. Jackson Washburn	53	Senior Vice President
Thomas E. Thurmond	42	Senior Vice President
Bruce D. McFarland	59	Vice President and Treasurer
Lawrence C. Smith	62	Vice President, Controller and Chief Accounting Officer
John R. Butler, Jr. †	77	Director, Chairman of the Board
Randall H. Breitenbach *	55	Director, Vice Chairman of the Board
David B. Kilpatrick †	66	Director
Gregory J. Moroney †	64	Director
Kurt A. Talbot	54	Director
Charles S. Weiss *†	63	Director
Donald D. Wolf †	72	Director

* Standing for re-election to the Board.

† Independent Directors.

Executive Officers of our General Partner

Halbert S. Washburn has been the Chief Executive Officer of our General Partner since April 2010. He served as Co-Chief Executive Officer and a director of our General Partner from March 2006 until April 2010 and was the Chairman of the Board from July 2008 to April 2010. In December 2011, Mr. Washburn was reappointed as a member of the Board of our General Partner. Mr. Washburn currently is the President and a director of Pacific Coast Energy Holdings LLC ("PCEH"), the indirect owner of PCEC, and is the co-founder and was the Co-Chief Executive Officer of PCEC's predecessors from 1988 to 2012. For additional information concerning PCEH and PCEC, please see "Certain Relationships and Related Transactions — General." Mr. Washburn is the brother of W. Jackson Washburn, our General Partner's Senior Vice President. Since December 2005, Mr. Washburn has served as a member of the board of directors and currently serves on the compensation committee of Rentech, Inc., a publicly traded wood fibre processing and wood pellet production company. He also served on its audit committee from 2005 to 2012. In June 2011, he was appointed Chairman of the Rentech, Inc. board of directors. From July 2011 to April 2015, Mr. Washburn served on the board of directors of Rentech Nitrogen Partners, L.P., a nitrogen fertilizer company formed by Rentech, Inc. as a publicly traded master limited partnership. In September 2013, Mr. Washburn was appointed to, and currently serves on, the board of directors of Jones Energy, Inc., a publicly traded independent oil and natural gas company engaged in the development and acquisition of oil and natural gas properties in the Anadarko and Arkoma basins of Texas and Oklahoma. He also currently serves on its audit, compensation and nominating and corporate governance committees. He has been a member of the California Independent Petroleum

Association since 1995 and served as Chairman of the executive committee of the board of directors from 2008 to 2010. He has also served as a board member, including Chairman of the board of directors, of the Stanford University Petroleum Investments Committee. Mr. Washburn holds a B.S. degree in Petroleum Engineering from Stanford University.

Mr. Washburn has a distinguished career as an executive in the oil and gas industry. His more than 30 years of management experience in the oil and gas industry provides Mr. Washburn with a keen understanding of our operations and an in-depth knowledge of our industry. The Board has determined that Mr. Washburn's experience serving on boards of directors of both public and private companies allows him to provide the Board with a variety of perspectives on corporate governance and other issues, and therefore he should serve on the Board.

Mark L. Pease has been the Chief Operating Officer and an Executive Vice President of our General Partner since December 2007. Effective December 31, 2012, Mr. Pease was appointed President and Chief Operating Officer of our General Partner. Mr. Pease also serves as the Chief Operating Officer of PCEH. Prior to joining our General Partner, Mr. Pease served as Senior Vice President, E&P Technology & Services for Anadarko Petroleum, an international and domestic oil and natural gas exploration and production company ("Anadarko"). Mr. Pease joined Anadarko in 1979 as an engineer, and served as Senior Vice President, North America from 2004 to 2006 and as Vice President, U.S. Onshore and Offshore from 2002 to 2004. Mr. Pease obtained a B.S. in Petroleum Engineering from the Colorado School of Mines.

James G. Jackson has been the Chief Financial Officer of our General Partner since July 2006 and an Executive Vice President since October 2007. Mr. Jackson also currently serves as the Chief Financial Officer of PCEH. Since June 2011, Mr. Jackson has served as a member of the board of directors of Niska Gas Storage Partners LLC ("Niska"), a publicly traded master limited partnership that owns and operates natural gas storage assets in North America. He also is a member of Niska's audit, compensation and conflicts committees. Before joining our General Partner, Mr. Jackson served as Managing Director of the Global Markets and Investment Banking Group for Merrill Lynch & Co., a global financial management and investment banking firm. Mr. Jackson joined Merrill Lynch in 1992 and was elected Managing Director in 2001. Previously, Mr. Jackson was a Financial Analyst with Morgan Stanley & Co. from 1986 to 1989 and was an Associate in the Mergers and Acquisitions Group of the Long-Term Credit Bank of Japan from 1989 to 1990. Mr. Jackson obtained a B.S. in Business Administration from Georgetown University and an M.B.A. from the Stanford Graduate School of Business.

Gregory C. Brown has been the General Counsel and Executive Vice President of our General Partner since December 2006. In January 2013, Mr. Brown was appointed General Counsel, Executive Vice President and Chief Administrative Officer of our General Partner. Mr. Brown also currently serves as General Counsel and Executive Vice President of PCEH. He also serves on the executive committee and the board of directors of the California Independent Petroleum Association. Before joining our General Partner, Mr. Brown was a partner at Bright and Brown, a law firm specializing in energy and environmental law that he co-founded in 1981. Mr. Brown earned a B.A. degree from George Washington University, with Honors, Phi Beta Kappa, and a J.D. from the University of California, Los Angeles. Mr. Brown was Mayor and has served on the City Council of the City of La Canada Flintridge from 2003 to 2011.

W. Jackson Washburn has been a Senior Vice President of our General Partner since April 2009 and has served as Vice President — Business Development since August 2007. Mr. Washburn also currently serves as Vice President, Real Estate of PCEH. Mr. Washburn is the brother of Halbert S. Washburn, our General Partner's Chief Executive Officer. Since joining the predecessor of PCEC in 1992, Mr. Washburn has served in a variety of capacities, and has served as President of Pacific Coast Land Company LLC, a subsidiary of PCEC, since 2000. Mr. Washburn obtained a B.A. in Psychology from Wake Forest University.

Thomas E. Thurmond has been a Senior Vice President of our General Partner since July 2015 and previously served as Vice President — Operations Support since August 2013. Since 2012, Mr. Thurmond has served as a member of the board of directors of C12 Energy, Inc., a privately held oil and gas company primarily engaged in the rehabilitation of mature oil fields through carbon dioxide injection. Prior to joining our General Partner, from 2007 to 2013, Mr. Thurmond served as Engineering Manager/Principal of Legado Resources LLC, a Houston based oil and gas company focused on acquiring and developing secondary and tertiary oil recovery projects throughout the United States. From 2005 to 2007, Mr. Thurmond was a Business Development Engineer at The Houston Exploration Company. Previously, he was a Senior Reservoir Engineer at Anadarko from 1999 to 2005 and a Production Engineer from 1997 to 1999. Mr. Thurmond obtained his B.S. in Petroleum Engineering from Texas A&M University.

Bruce D. McFarland has been the Treasurer of our General Partner since March 2006 and a Vice President since April 2009. Mr. McFarland served as the Chief Financial Officer of our General Partner from March 2006 through June 2006. Mr. McFarland also currently serves as Treasurer of PCEH. Since joining our Predecessor in 1994, Mr. McFarland served as Controller and Treasurer for more than five years. Before joining our Predecessor, Mr. McFarland served as Division Controller of IT Corporation and worked at Price Waterhouse as a Certified Public Accountant. Mr. McFarland obtained a B.S. in Civil Engineering from the University of Florida and an M.B.A. from the University of California, Los Angeles.

Lawrence C. Smith has been the Controller of our General Partner since June 2006 and a Vice President since April 2009. Mr. Smith is also the Chief Accounting Officer of our General Partner. He also currently serves as the Controller of PCEH. Before joining our General Partner, Mr. Smith served as the Corporate Accounting Compliance and Implementation Manager of Unocal Corporation, which was an oil and natural gas production and exploration development company ("Unocal"), from 2000 through 2006. Mr. Smith worked at Unocal from 1981 through 2006 and held various managerial positions in Unocal's accounting and finance organizations. Mr. Smith obtained a B.B.A. in Accounting from the University of Houston, an M.B.A. from the University of California, Los Angeles, and is a Certified Public Accountant.

Directors of our General Partner

John R. Butler, Jr. has been a member of the Board since October 2006. Mr. Butler was appointed as the Chairman of the Board in April 2010. Since 1976, Mr. Butler has been Chairman of the board of directors of J.R. Butler and Company, a reservoir engineering company. Mr. Butler was a member of the board of directors of Anadarko Petroleum Corporation, an international and domestic oil and natural gas exploration and production company, from 1996 through 2011. He served on Anadarko's audit committee from 1996 through 2011 and was chairman of that committee for approximately five years during that period, served on its executive committee from 1998 to 2008 and served on its nominating and governance committee from 2006 through 2011. In addition, he currently serves on the board of directors of the Texas Tri-Cities chapter of the National Association of Corporate Directors. Mr. Butler also was formerly a member of the following boards of directors: Premier Instruments, Inc., makers of oil and gas field metering system; Kelman Technologies Inc., a publicly traded seismic and data management company; Howell Petroleum Corp., a publicly traded oil and gas producer with assets in Wyoming and Montana; and Bayou Resources, an oil and gas exploration company. Mr. Butler was Chairman and Chief Executive Officer of GeoQuest International Holdings, Inc., Senior Chairman of Petroleum Information Corp., and Vice Chairman of Petroleum Information/Dwights, L.L.C., suppliers of commercial petroleum data and information services, until 1997. He is a member of the Society of Petroleum Evaluation Engineers and was Chairman of the Society of Exploration Geophysicists Foundation until December 2001. He has a B.S. in Chemical Engineering from Stanford University. Mr. Butler has also completed courses at, among other institutions, Harvard University, Columbia University and the National Association of Corporate Directors, designed to educate and prepare public directors for serving on audit committees.

Mr. Butler's more than 40 years of experience in the oil and gas industry provides him with a keen understanding of the operations of the Partnership and an in-depth knowledge of our industry. Serving as Chairman of the board of directors of J.R. Butler and Company and having served as Chairman and Chief Executive Officer of GeoQuest International Holdings, Inc., Senior Chairman of Petroleum Information Corp., and Vice Chairman of Petroleum Information/Dwights, L.L.C., Mr. Butler offers a wealth of management experience and business understanding. The Board has determined that Mr. Butler's services on the board of directors and committees of Anadarko and other public company boards of directors allow him to provide the Board with a variety of perspectives on corporate governance and other issues, and therefore he should serve on the Board.

Randall H. Breitenbach was the President of our General Partner from April 2010 until December 2012. Effective December 2012, Mr. Breitenbach retired as President and was appointed Vice Chairman of the Board of our General Partner. From March 2006 until April 2010, he served as Co-Chief Executive Officer and a director of our General Partner. In December 2011, Mr. Breitenbach was reappointed as a member of the Board of our General Partner. Mr. Breitenbach also currently serves as the Chief Executive Officer and the Chairman of the board of directors of PCEH, and is the co-founder and was the Co-Chief Executive Officer of PCEC and its predecessors from 1988 to 2012. For additional information concerning PCEH and PCEC, please see "Certain Relationships and Related Transactions — General." Mr. Breitenbach is a founder of Coldsmoke Apparel, a privately held outerwear clothing company, and currently serves as its Chief Executive Officer. Mr. Breitenbach currently serves as a Trustee and is Chairman of the governance and nominating committee for Hotchkis and Wiley Funds, which is a mutual funds company. He has also served as a board member, including Chairman of the board of directors, of the Stanford University Petroleum Investments Committee. Mr. Breitenbach holds both a B.S and M.S. degree in Petroleum Engineering from Stanford University and an M.B.A. from Harvard Business School.

Mr. Breitenbach has a distinguished career as an executive in the oil and gas industry. His more than 30 years of management experience in the oil and gas industry provides Mr. Breitenbach with a keen understanding of our operations and an in-depth knowledge of its industry. The Board has determined that Mr. Breitenbach's experience serving on boards of directors of companies allows him to provide the Board with a variety of perspectives on corporate governance and other issues, and therefore he should serve on the Board.

David B. Kilpatrick has been a member of the Board since March 2008 and is currently the Chairman of the Compensation and Governance Committee. Mr. Kilpatrick has been the President of Kilpatrick Energy Group, which invests in oil and gas ventures and provides executive management consulting services, since 1998. Mr. Kilpatrick currently serves on the board of directors and on the governance committee of Cheniere Energy, Inc., an owner, operator and developer of liquefied natural gas ("LNG") receiving terminals and served on its audit committee from 2003 to 2011. Since 2011, Mr. Kilpatrick has served on the board of managers of Woodbine Holdings LLC, a privately held, oil and natural gas company engaged in the acquisition, development, exploitation and production of crude oil and natural gas properties in Texas. Since 2014, he has served as Chairman of the board of directors of Applied Natural Gas Fuels, Inc., a producer and distributor of LNG fuel for the transportation and industrial markets. He also served on the boards of directors and the audit committees of PYR Energy, an acquisition, exploration, and oil and gas production company with projects in the United States and Canada from 2001 to 2007 and of Whittier Energy Corporation, an oil and gas exploration and production company, from 2004 to 2007. Mr. Kilpatrick brings to the Board over 30 years of executive, managerial and operating experience in the oil and gas industry and extensive experience in technical and economic evaluations of acquisitions and investment proposals. He was the President and Chief Operating Officer of Monterey Resources, Inc., an independent oil and gas producer in California, from 1996 to 1998 and held various management positions at Santa Fe Energy Resources, a worldwide oil and gas exploration and development company, from 1983 to 1996. He has a B.S. in Petroleum Engineering from the University of Southern California ("USC") and a B.A. in Geology and Physics from Whittier College. Mr. Kilpatrick has also attended post-graduate courses at the graduate school of business administration at USC and professional courses in business and management at USC, the Wharton School at the University of Pennsylvania and Cornell University. He was the President of the California Independent Petroleum Association from 1992 to 1994 and currently serves on its board of directors. Mr. Kilpatrick also currently serves on the board of directors of the Independent Oil Producers Agency and has served on the board of directors of the Western States Petroleum Association. He is a member of the Society of Petroleum Engineers.

Mr. Kilpatrick has a distinguished career as an executive in the oil and gas industry. His more than 30 years of management experience in the oil and gas industry provides Mr. Kilpatrick with a keen understanding of our operations and an in-depth knowledge of our industry. The Board has determined that Mr. Kilpatrick's services on the board of directors and audit committee of Cheniere Energy and other public company boards of directors allow him to provide the Board with a variety of perspectives on corporate governance and other issues, and therefore he should serve on the Board.

Gregory J. Moroney has been a member of the Board since October 2006. He also served on the board of directors of the general partner of PCEC from 2004 to 2008. Currently, Mr. Moroney is the Managing Member and Owner of Energy Capital Advisors, LLC, which assists independent energy companies and energy fund managers in raising funds privately, a position he has held since January 2003. Since June 2005, he has also been a Senior Financial Consultant for Ammonite Resources LLC, a petroleum and mineral consulting company. Since 2007, Mr. Moroney has served on and currently serves on the board of directors and as a member of the audit and remuneration and nominating committees of Xcite Energy Limited, BVI, a publicly traded oil exploration and development company. Mr. Moroney served as Managing Director for Deutsche Bank Securities Inc. from 1993 to December 2002, where he supervised and managed a large oil and gas mezzanine loan portfolio with commodity hedges and originated more than $10 billion of energy related project loans. From 1977 to 1993, Mr. Moroney was with Citicorp/Citibank in Calgary, Toronto and New York. At Citibank, Mr. Moroney managed large energy loan portfolios and worked in a variety of finance areas, including capital markets, energy hedging, acquisition loan syndications, project finance, debt restructuring and mergers and acquisitions. In 1992, Mr. Moroney also obtained a Series 7/General Securities license from what is now the Financial Industry Regulatory Authority. He graduated with a B.A. from Yale University.

Mr. Moroney brings to the Board over 25 years of experience as an energy finance specialist. The Board has determined that his extensive training in the review and analysis of financial statements, energy asset valuations, capital structures and capital markets, as well as his experience with the creation and review of corporate budgets, management goals, compensation and staffing issues provides a valuable perspective and insights to the Board and the Audit Committee, and therefore he should serve on the Board. Serving on the board of directors and committees of Xcite Energy, Mr. Moroney also brings directorial and governance experience to the Board.

Kurt A. Talbot has been a member of the Board since April 8, 2015. Mr. Talbot is currently Senior Advisor with EIG Management Company, LLC and a member of the Executive Committee of EIG Global Energy Partners ("EIG"), a leading institutional investor to the global energy sector. From 2007 through 2014, Mr. Talbot was the Chief Investment Officer for EIG, having primary responsibility for the group's global investment activity. Mr. Talbot first joined EIG in 1990 and played an integral role in the establishment of EIG's oil and gas practice. In 2003, Mr. Talbot left EIG and joined Goldman Sachs Group, Inc., where he founded and served as head of its E&P Capital Group. In 2005, Mr. Talbot returned to EIG as Managing Director and Head of Oil and Gas. From March 2012 to April 2015, Mr. Talbot served on the board of directors of Plains Offshore Operations Inc., a subsidiary of Freeport-McMoRan Inc., a public, U.S.-based natural resource company. Mr. Talbot began his professional career with Trafalgar House Oil & Gas, a British independent, holding both engineering and commercial positions in Houston and London, respectively. Mr. Talbot received a B.S. in Petroleum Engineering from Louisiana State University and an M.B.A. from Texas A&M University. Mr. Talbot is a registered professional engineer in the State of Texas.

Mr. Talbot brings to the Board extensive management and operational experience in the financial energy industry, including his current service as Vice Chairman for EIG and his previous service as Chief Investment Officer for EIG. Mr. Talbot's experience working in the global oil and gas industry both in engineering and commercial positions provides the Board with critical skills in the areas of aligning financial and strategic initiatives and risk management. For these reasons, the Board has determined that Mr. Talbot should serve on the Board.

Charles S. Weiss has been a member of the Board since October 2006 and is currently the Chairman of the Audit Committee. Mr. Weiss served as lead independent director of the Board from July 2008 until April 2010. He is a Founder and Managing Partner of JOG Capital Inc., a provider of private equity to Canadian exploration and production companies, a position that he has held since July 2002. Mr. Weiss currently serves on the boards of directors of JOG Capital Inc. and the National Forest Foundation, a non-profit foundation promoting the United States National Forest System. He previously served on the boards of directors and audit committees of three oil and gas companies from 2007 to 2009: Exshaw Oil Corp., Masters Energy Inc., and Livingston Energy Ltd. Mr. Weiss also served on the reserve committees at Masters Energy and Exshaw Oil. In addition, Mr. Weiss served as Managing Director and Head of Royal Bank of Canada's Capital Markets Energy Group from October 2002 through May 2006. From June 2001 to July 2002, Mr. Weiss pursued various investment opportunities, which included the establishment of JOG Capital Inc. Previously, he was the Managing Director and Head of the Energy and Power Group with Bank of America Securities from 1998 to June 2001. Mr. Weiss obtained a B.A. in Physics from Vanderbilt University and an M.B.A. from the University of Chicago Graduate School of Business.

Mr. Weiss brings to the Board extensive management and operating experience in the oil and gas industry. The Board has determined that his experience as the Founder and Managing Partner of JOG Capital and previously as the Managing Director and Head of Royal Bank of Canada's Capital Markets Energy Group make him a valuable contributor to the Board. The Board has also determined that, having served on the board of directors and audit committees of three oil and gas companies from 2007 to 2009, Mr. Weiss also brings considerable directorial and governance experience to the Board. For these reasons, the Board has determined that Mr. Weiss should serve on the Board. Given his expertise in finance and accounting, Mr. Weiss has been determined to be an audit committee financial expert by the Board.

Donald D. Wolf has been a member of the Board since November 2014. Previously, Mr. Wolf served as the Chairman of the board of directors of the general partner of QR Energy, LP, Chief Executive Officer of the general partner of the QR Funds and also served as the Chief Executive Officer of Quantum Resources Management from 2006 until 2009. Prior to serving as the Chief Executive Officer of Quantum Resources Management, Mr. Wolf served as President and Chief Executive Officer of Aspect Energy, LLC, a privately held independent exploration and energy investment company, from 2004 until 2006. Prior to joining Aspect, Mr. Wolf served as Chairman and Chief Executive Officer of Westport Resources Corporation, a an independent oil and gas exploration and production company, from 1996 to 2004. Mr. Wolf has also served as President and Chief Operating Officer of United Meridian Corporation, an independent energy company engaged in the exploration for and development, production and acquisition of oil and natural gas in North American and certain international regions, from 1994 to 1996, President and Chief Operating Officer of General Atlantic Resources, Inc., a Denver-based independent oil and gas operating company that acquired, developed and exploited producing oil and gas properties, from 1981 to 1993 and Co-Founder and President of Terra Marine Energy Company from 1977 to 1981. He began his career in 1965 with Sun Oil Company in Calgary, Alberta, Canada, working in operations and land management. Following Sun Oil Company, he assumed land management positions with Bow Valley Exploration, Tesoro Petroleum Corp. and Southland Royalty Company from 1971 through 1977. Mr. Wolf currently serves as a director of MarkWest Energy Partners, L.P., Enduring Resources, LLC, Laredo Petroleum, LLC and Aspect Energy, LLC. Mr. Wolf is a former director of the Independent Petroleum Association of Mountain States. Mr. Wolf received a B.S. in Business Administration from Greenville College.

Mr. Wolf brings to the Board significant experience in the oil and gas industry having served in the executive officer roles described above, and has a keen understanding of the operations of QR Energy, LP, which we acquired. The Board has determined that Mr. Wolf's experience serving on boards of directors of companies allows him to provide the Board with a variety of perspectives on corporate governance and other issues, and therefore he should serve on the Board.

GOVERNANCE MATTERS

General

The Partnership Agreement provides that an annual meeting of the limited partners for the election of directors to the Board will be held at such date and time as may be fixed from time to time by our General Partner. The Board has determined that the 2016 Annual Meeting shall be held on April 28, 2016. At the Annual Meeting, the limited partners will vote together as a single class for the election of three directors (our Class II Directors) to the Board. At each annual meeting, the limited partners entitled to vote will elect by a plurality of the votes cast at such meeting persons to serve on the Board who are nominated in accordance with the provisions of the Partnership Agreement.

With respect to the election of directors to the Board, (1) we and our General Partner will not be entitled to vote common units that are otherwise entitled to vote at any meeting of the limited partners, and (2) if at any time any person or group beneficially owns 20% or more of the Outstanding Partnership Securities (as defined in the Partnership Agreement) of any class then outstanding, then all Partnership Securities (as defined in the Partnership Agreement) owned by such person or group in excess of 20% of the Outstanding Partnership Securities of the applicable class may not be voted, and in each case, the foregoing units will not be counted when calculating the required votes for such matter and will not be deemed to be Outstanding (as defined in the Partnership Agreement) for purposes of determining a quorum for such meeting. Such units will not be treated as a separate class of Partnership Securities for purposes of the Partnership Agreement. The number of directors constituting the whole Board may not be less than five or more than nine as established from time to time by a resolution adopted by a majority of the directors. The Board has been divided into three classes, Class I, Class II and Class III. The term of the Class II Directors will expire at the Annual Meeting. The term of the Class III Directors will expire at the annual meeting to be held in 2017. The directors designated to Class I are serving for a term that expires at the annual meeting to be held in 2018. Successors to the class of directors whose term expires at an annual meeting will be elected for a three-year term.

The Board; Leadership Structure; Executive Sessions

The Board currently has a total of eight members. At present, the directors and the class in which each such director is a member are designated as follows:

- John R. Butler, Jr. — Class I;
- Gregory J. Moroney — Class I;
- Randall H. Breitenbach — Class II;
- Halbert S. Washburn — Class II;
- Charles S. Weiss — Class II;
- David B. Kilpatrick — Class III;
- Kurt Talbot — Class III; and
- Donald D. Wolf — Class III.

In April 2010, the Board separated the positions of Chairman of the Board and Chief Executive Officer and appointed Mr. Butler, an independent director, as Chairman. Separating these positions allows our Chief Executive Officer to focus on the day-to-day business and operations of the Partnership, while allowing the Chairman of the Board to lead the Board in its fundamental role of providing advice to and independent oversight of management. The Board recognizes the time, effort, and energy that the Chief Executive Officer must devote to his position in the current business environment, as well as the commitment necessary to serve as Chairman of the Board. The Board believes that having an independent director serve as Chairman is the appropriate leadership structure for the Partnership at this time.

Our directors meet in executive sessions on a regular basis and hold executive sessions with both internal and external auditors as well as members of management.

Director Independence

Even though most companies with securities listed on The NASDAQ Stock Market LLC are required to have a majority of independent directors serving on the board of directors, The NASDAQ Stock Market LLC does not require a listed limited partnership like us to have a majority of independent directors on the Board. Nevertheless, at present, we meet this requirement. The Board has determined that five of its members — Messrs. Butler, Kilpatrick, Moroney, Weiss and Wolf — meet the independence standards established by The NASDAQ Stock Market LLC.

Board Committee Composition

The Board has two standing committees: the Audit Committee and the Compensation and Governance Committee. The Audit Committee and the Compensation and Governance Committee each have a charter, which is available in the "About Breitburn — Corporate Governance" section of our website at *http://www.breitburn.com*.

Audit Committee

The members of the Audit Committee are currently Messrs. Kilpatrick, Moroney, Weiss and Wolf. The NASDAQ Stock Market LLC and SEC rules require that the Audit Committee be comprised of at least three directors determined to be independent according to particular rules that apply to members of the Audit Committee. The Board has determined that Messrs. Kilpatrick, Moroney, Weiss and Wolf meet these independence standards. The Board has also determined that one member of the Audit Committee, Mr. Weiss, qualifies as an "Audit Committee Financial Expert" as defined by SEC rules.

The Audit Committee's primary functions are to assist the Board with respect to:

- the review of the financial statements and the financial reporting of the Partnership;
- the assessment of the Partnership's internal controls;
- the appointment, compensation and evaluation of the external auditor and the oversight of the external audit process;
- the performance of the Partnership's internal audit function;
- the review and approval on an ongoing basis of all material related party transactions required to be approved by the Board;
- the resolution of any conflicts of interest with our General Partner and its affiliates;
- oversight of risk management at the Partnership; and
- the preparation of the Audit Committee report included in this proxy statement.

As provided in the Partnership Agreement, the Board may rely on the Audit Committee, acting as the Conflicts Committee under the Partnership Agreement, to determine if the resolution of a conflict of interest with our affiliates is fair and reasonable to us. Any matters approved by the Audit Committee in good faith will be permitted and deemed approved by all of our partners and not a breach by our General Partner of any duties it may owe us or our unitholders. During 2015, the Conflicts Committee met three times to discuss matters related to the Third Amended and Restated Administrative Services Agreement with PCEC.

Compensation and Governance Committee

The members of the Compensation and Governance Committee currently are Messrs. Butler, Kilpatrick, Moroney and Weiss. The Compensation and Governance Committee's primary functions are to:

- review and approve the compensation of our executive officers and directors;
- review the executive compensation disclosure to be included in our Annual Report on Form 10-K and proxy statement;
- determine and make grants under the First Amended and Restated Breitburn Energy Partners LP 2006 Long-Term Incentive Plan (as amended, "Long-Term Incentive Plan");
- review management's recommendations for employee compensation and benefits;

- assist the Board in corporate governance matters; and
- recommend to the Board new candidates for election to the Board and assist the Board in evaluating the performance of its members.

The Chief Executive Officer of our General Partner also participates in the compensation process by: (1) providing evaluations of other executive officers; (2) presenting overall results of the Partnership's performance based upon the achievements of each functional department; (3) in some years, reviewing peer group information and compensation recommendations and providing feedback regarding the potential impact to the Partnership; and (4) participating in Compensation and Governance Committee meetings at the invitation of the committee, subject to exclusion from certain meetings or portions thereof intended to be exclusive of management. The Chief Financial Officer of our General Partner evaluates the financial implications and affordability of compensation programs. Other executive officers may periodically participate in the compensation process and Compensation and Governance Committee meetings at the invitation of the committee to advise on performance and/or activity in areas with respect to which these executive officers have particular knowledge or expertise. Additional information regarding the Compensation and Governance Committee's processes and procedures for the consideration and determination of executive compensation are discussed in "Compensation Discussion and Analysis" below.

Compensation Committee Interlocks and Insider Participation

During 2015, our Compensation and Governance Committee was comprised of the following independent directors: Messrs. Butler, Kilpatrick, Moroney and Weiss. None of the members of our Compensation and Governance Committee (i) was an officer or employee of the Partnership or of our General Partner, (ii) was formerly an officer of the Partnership or of our General Partner or (iii) had any relationship requiring disclosure under the SEC's rules governing disclosure of related person transactions (Item 404 of Regulation S-K). Additionally, no executive officer of our General Partner served as a member of the compensation committee or as a director of any entity where an executive officer of such entity is a member of the Board or our Compensation and Governance Committee, except that Messrs. Halbert S. Washburn and Breitenbach served as directors of PCEH.

Board and Committee Meetings

During 2015, the Board had fifteen regularly scheduled and special meetings (including our 2015 Annual Meeting), our Audit Committee had five meetings, and our Compensation and Governance Committee had five meetings. None of our directors attended fewer than 75% of the aggregate number of meetings of the Board and committees of the Board on which the director served.

Board Nominations; Consideration of Diversity

Nominations of persons for election to the Board may be made at an annual meeting of the limited partners only (1) pursuant to our General Partner's notice of meeting (or any supplement thereto), (2) by or at the direction of the Board or any committee thereof, or (3) by any limited partner who was a record holder at the time the notice provided for in the Partnership Agreement is delivered to our General Partner, who is entitled to vote at the meeting and who complies with the notice procedures set forth in the Partnership Agreement.

The entire Board is responsible for nominating members for election to the Board and filling vacancies on the Board that may occur between annual meetings. The Board believes that all directors must possess a considerable amount of business management (such as experience as an executive), financial background, oil and gas related business experience and public company or partnership experience. The Compensation and Governance Committee is responsible for identifying, screening and recommending candidates to the entire Board for prospective Board membership. When searching for new candidates, the Compensation and Governance Committee will consider the evolving needs of the Board and will search for candidates that fill any current or anticipated future needs. The Compensation and Governance Committee first will consider a candidate's management and business experience and then consider issues of judgment, background, stature, conflicts of interest, integrity, ethics and commitment to the goal of maximizing unitholder value when considering director candidates. The Compensation and Governance Committee also will consider diversity, such as diversity of gender, race and national origin, education, professional experience and differences in viewpoints and skills. The Compensation and Governance Committee does not have a formal policy with respect to diversity. However, the Board and the Compensation and Governance Committee believe that it is essential that Board members represent diverse viewpoints. In considering candidates for the Board, the Compensation and Governance Committee will consider the entirety of each candidate's credentials and qualifications in the context of these standards. With respect to the nomination of continuing directors for re-election, the individual's contributions to the Board will also be considered.

Nomination of Director Candidates by Unitholders

Unitholders of record may nominate directors for election to the Board at any annual meeting, provided that they comply with the requirements described below and in the section of this proxy statement entitled "Proposals for the Next Annual Meeting." While we do not have a policy that specifically addresses the consideration of director candidates recommended by unitholders, there would be no differences in the manner and criteria by which the Compensation and Governance Committee and the Board evaluate director candidates recommended by unitholders and those recommended by other sources.

For any nominations brought before an annual meeting by a unitholder, the unitholder must give timely notice thereof in writing to our General Partner. The notice must contain certain information as described in the Partnership Agreement. To be timely, a unitholder's notice must be delivered to our General Partner not later than the close of business on the 90th day, nor earlier than the close of business on the 120th day, prior to the first anniversary of the preceding year's annual meeting (provided, however, that in the event that the date of the annual meeting is more than 30 days before or more than 70 days after such anniversary date, notice by the unitholder must be so delivered not earlier than the close of business on the 120th day prior to such annual meeting and not later than the close of business on the later of the 90th day prior to such annual meeting or the 10th day following the day on which public announcement of the date of such meeting is first made by the Partnership or our General Partner).

In the event that the number of directors to be elected to the Board is increased effective at an annual meeting and there is no public announcement by the Partnership or our General Partner naming the nominees for the additional directorships at least one hundred days prior to the first anniversary of the preceding year's annual meeting, a limited partner's notice will also be considered timely, but only with respect to nominees for the additional directorships, if it is delivered to our General Partner not later than the close of business on the 10th day following the day on which such public announcement is first made by the Partnership or our General Partner.

Nominations of persons for election to the Board also may be made at a special meeting of limited partners at which directors are to be elected in accordance with the provisions of the Partnership Agreement.

Only such persons who are nominated in accordance with the procedures set forth in the Partnership Agreement will be eligible to be elected at an annual or special meeting of limited partners to serve as directors. Notwithstanding the foregoing, unless otherwise required by law, if the unitholder (or a qualified representative of the unitholder) does not appear at the annual or special meeting of limited partners to present a nomination, such nomination will be disregarded notwithstanding that proxies in respect of such vote may have been received by our General Partner or the Partnership.

In addition to the provisions described above and in the Partnership Agreement, a unitholder must also comply with all applicable requirements of the Exchange Act and the rules and regulations thereunder; provided however, that any references in the Partnership Agreement to the Exchange Act or the rules promulgated thereunder are not intended to and do not limit any requirements applicable to nominations pursuant to the Partnership Agreement, and compliance with the Partnership Agreement is the exclusive means for a limited partner to make nominations.

The public announcement of an adjournment, postponement or extension of the Annual Meeting will not commence a new time period (or extend any time period) for the giving of a unitholder's notice as described above.

The Board's Role in Risk Oversight

While the Board has the ultimate oversight responsibility for the risk management process, certain committees also have responsibility for risk management. On behalf of the Board, the Audit Committee plays a key role in the oversight of the Partnership's risk management function. The Audit Committee reviews our risk management policies, any major financial risks and the steps taken by management to monitor and control those risks. The Audit Committee also oversees the Partnership's Risk Management Committee (the "RMC") comprised of our General Partner's Chief Executive Officer, President, Chief Financial Officer, General Counsel and Treasurer, each of whom supervises day-to-day risk management throughout the Partnership. The RMC is not a committee of the Board. The RMC assists the Partnership in identifying potential material risks and implementing appropriate mitigation measures. Members of the RMC meet formally at least once a month, to review and monitor potential risks, including commodity and interest rate hedging risk, counterparty credit exposure risk, financial risk and insurance policy structure and indemnity arrangements. The RMC reports directly to the Audit Committee. The Audit Committee's role in the Partnership's risk oversight process includes receiving at least quarterly reports from members of the RMC on areas of material risk to the Partnership, including operational, financial, legal and regulatory, and strategic risks and highlighting any new risks the RMC has identified that may have arisen since they last met. The Audit Committee receives these reports from management to enable it to understand our risk identification, risk management and risk mitigation strategies. The Audit Committee reviews the Partnership's hedging policy at least once annually. The Compensation and Governance Committee oversees risk management as it relates to our compensation plans, policies and practices and has met with management to review whether our compensation programs may create incentives for our employees to take excessive or inappropriate risks which could have a material adverse effect on the Partnership. The Board is advised by the committees of significant risks and management's response via periodic updates.

Unitholder Communications Policy

To ensure that the Partnership has in place policies and programs that enable the Partnership to communicate effectively and in a timely manner with its unitholders, other stakeholders, analysts and the public generally, the Board has adopted the Disclosure Policy of the Partnership and the General Partner (the "Disclosure Policy"). The Disclosure Committee established under the Disclosure Policy reports annually to the Compensation and Governance Committee with respect to any desirable changes to the Disclosure Policy and with respect to compliance with the policy in order to ensure its objectives are being achieved and that the Disclosure Committee is effectively implementing the policy.

Any unitholder of the Partnership may contact the Board (including any individual director) by email at directors@breitburn.com or in writing c/o the Corporate Secretary at the Partnership's corporate headquarters at 707 Wilshire Boulevard, Suite 4600, Los Angeles, CA 90017. Matters relating to the Partnership's accounting, internal accounting control or audit matters will be referred to the Audit Committee, communications addressed to individual directors will be forwarded to the applicable addressee(s), and other matters will be referred to the Chairman of the Board.

Director Attendance at Annual Meetings of Limited Partners

We believe that there are benefits to having members of the Board attend annual meetings of limited partners. From time to time, however, a member of the Board might have a compelling and legitimate reason for not attending an annual meeting. As a result, the Board has decided that director attendance at annual meetings should be strongly encouraged, but is not required. All the members of the Board except Mr. Breitenbach attended our annual meeting of limited partners held on June 18, 2015.

Code of Conduct

The Board has adopted a Code of Business Conduct (the "Code of Conduct"), which includes a series of corporate governance principles applicable to all our and our General Partner's employees, officers and directors, and is designed to affirm our high standards of business conduct and to emphasize the importance of integrity and honesty in the conduct of our business. We believe that the ethical foundations outlined in our Code of Conduct are critical to our ongoing success. The Code of Conduct is distributed to all of our employees and is posted in the "About Breitburn — Corporate Governance" section of our website at *http://www.breitburn.com*.

Code of Ethics for Financial Employees

We have adopted a Code of Ethics for Chief Executive Officers and Senior Officers, which applies to our General Partner's Chief Executive Officer, President, Chief Financial Officer, Controller, Chief Operating Officer, General Counsel and all other Vice Presidents and senior officers of the General Partner (the "Code of Ethics"). The Code of Ethics complies with the rules of the SEC and Rule 406 of the Sarbanes-Oxley Act of 2002. The Code of Ethics is intended to deter wrongdoing and to promote honest and ethical conduct by such officers. The Code of Ethics is posted in the "About Breitburn — Corporate Governance" section of our website at *http://www.breitburn.com*.

AUDIT COMMITTEE REPORT

The Audit Committee oversees the Partnership's financial reporting process on behalf of the Board. Management has the primary responsibility for the financial statements and the reporting process. In fulfilling its oversight responsibilities, the Audit Committee reviewed and discussed with management and with PricewaterhouseCoopers LLP, the Partnership's independent registered public accounting firm, the audited financial statements contained in the Partnership's Annual Report on Form 10-K for the fiscal year ended December 31, 2015. During the year ended December 31, 2015, the Audit Committee was chaired by Charles S. Weiss and also included David B. Kilpatrick, Gregory J. Moroney and Donald D. Wolf.

PricewaterhouseCoopers LLP is responsible for expressing an opinion on the conformity of the audited financial statements with accounting principles generally accepted in the United States of America. The Audit Committee reviewed and discussed with PricewaterhouseCoopers LLP their judgment as to the quality, not just the acceptability, of the Partnership's accounting principles and such other matters as are required to be discussed with the Audit Committee under generally accepted auditing standards.

The Audit Committee discussed with PricewaterhouseCoopers LLP those matters required to be discussed by Auditing Standard No. 16, "Communications with Audit Committees", as adopted by the Public Company Accounting Oversight Board. This included (a) the auditor's judgment about the quality, not just the acceptability, of the accounting principles as applied in our financial reporting, (b) the methods used to account for significant unusual transactions, (c) the effect of significant accounting policies in controversial or emerging areas for which there is a lack of authoritative guidance or consensus, (d) the process used by management in formulating particularly sensitive accounting estimates and the basis for the auditor's conclusions regarding the reasonableness of those estimates and (e) disagreements with management over the application of accounting principles, the basis for management's accounting estimates and disclosures in the financial statements. The Audit Committee received and reviewed the written disclosures and the letter from PricewaterhouseCoopers LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant's communications with the Audit Committee concerning the accountant's independence, and has discussed with PricewaterhouseCoopers LLP its independence from management and the Partnership.

Based on the reviews and discussions referred to above, the Audit Committee recommended to the Board that the audited financial statements for the year ended December 31, 2015 be included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2015 for filing with the SEC.

The Audit Committee:
Charles S. Weiss, Chairman
David B. Kilpatrick
Gregory J. Moroney
Donald D. Wolf

COMPLIANCE WITH SECTION 16(A) OF THE EXCHANGE ACT

Section 16(a) of the Exchange Act requires the directors and executive officers of our General Partner, and persons who own more than 10% of a registered class of our equity securities, to file reports of beneficial ownership on Form 3 and reports of changes in beneficial ownership on Form 4 or Form 5 with the SEC. Based solely on our review of the reporting forms and written representations provided to us from the individuals required to file reports, we believe that each of our executive officers and directors has complied with the applicable reporting requirements for transactions in our securities during the year ended December 31, 2015, except reports for additional restricted phantom units paid as distribution equivalents were filed one day late on May 20, 2015 by Messrs. Breitenbach, Halbert S. Washburn, Pease, Jackson, Brown and W. Jackson Washburn and reports for acquisitions of common units on March 19, 2015 and August 28, 2015 were filed late on February 22, 2016 by Mr. Wolf.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

General

As of March 4, 2016, affiliates of our General Partner, including directors and executive officers of our General Partner, owned 3,889,965 common units and 37,462,156 Series B units, collectively representing a 15.7% limited partner interest in us.

Mr. W. Jackson Washburn, who is the brother of Mr. Halbert S. Washburn, is an employee of Breitburn Management and serves as an officer of our General Partner and of PCEH, the indirect owner of PCEC. For the year ended December 31, 2015, Mr. W. Jackson Washburn received a base salary of $327,600, bonus payment of $111,385 and an equity grant on January 26, 2015 of 87,393 restricted phantom units.

At December 31, 2015, we had net current receivables of $1.7 million due from PCEC related to the ASA (as defined below), employee related costs and oil and gas sales made by PCEC on our behalf from certain properties. During 2015, the monthly charges to PCEC for indirect expenses totaled $8.4 million and charges for direct expenses including direct payroll and other direct costs totaled $9.6 million.

Distributions and Payments to Affiliates of Our General Partner

We will generally distribute all our available cash to all unitholders, including affiliates of our General Partner. Upon our liquidation, our limited partners, including affiliates of our General Partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Administrative Services Agreement

Concurrently with the completion of the initial public offering of Pacific Coast Oil Trust, which was formed by PCEC, Breitburn Management, our wholly owned subsidiary, entered into a Third Amended and Restated Administrative Services Agreement (as amended, the “ASA”) with PCEC with an effective date of April 1, 2012, pursuant to which Breitburn Management manages the operations of PCEC and provides administrative services such as accounting, corporate development, finance, land, legal and engineering to PCEC. Pursuant to the ASA, PCEC agreed to pay Breitburn Management a monthly fixed fee for indirect costs, including general and administrative costs, relating to the performance of Services (as defined in the ASA). The monthly fee is fixed at $700,000 through December 31, 2016. For periods on and after January 1, 2017, the monthly fee will be determined on a biannual basis.

Pursuant to amendments to the ASA, the initial term of the ASA had been extended to December 31, 2016; provided, however, in the event PCEC had not received certain drilling permits by December 31, 2015, PCEC retained the option to terminate the ASA effective as of June 30, 2016 by giving prior written notice to Breitburn Management of its intention to terminate the ASA by February 8, 2016. The ASA also provides for early termination on the happening of certain events.

Under the ASA, PCEC is also able to terminate such agreement by giving written notice of termination to Breitburn Management upon (1) a PCEC Change in Control (as defined in the ASA), (2) a BBEP Change in Control (as defined in the ASA), (3) a Breitburn Management Change in Control (as defined in the ASA), or (4) Breitburn Management’s failure to pay employees providing services within 30 days of the date such employees’ payment is due, subject to the terms of the ASA. In addition, after June 30, 2016, upon 180 days’ prior written notice, PCEC may elect to terminate the ASA effective as of the end of the 180 day period following the delivery of notice by PCEC to Breitburn Management. As defined in the ASA, a BBEP Change in Control and a Breitburn Management Change in Control include a change in control of the Partnership or Breitburn Management, respectively, effected through both Messrs. Halbert S. Washburn and Randall H. Breitenbach no longer being employed as Co-Chief Executive Officers of Breitburn GP or Breitburn Management, respectively. Mr. Breitenbach’s resignation as President of Breitburn GP effective December 31, 2012 did not trigger a change in control under the ASA. If the ASA is terminated by PCEC, under certain circumstances, PCEC will be obligated to promptly reimburse Breitburn Management for its reasonable expenses incurred in reducing its staffing, including, but not limited to reasonable severance payments, up to a maximum of the lesser of two times the monthly fixed fee in effect at the date of such termination and $2.0 million.

Breitburn Management will be able to terminate the ASA by giving written notice of such termination to PCEC upon the occurrence of a PCEC Change in Control.

In the event that PCEC, the Partnership or Breitburn Management becomes bankrupt or dissolves or commences liquidation or winding-up, the ASA will automatically terminate without notice to the other party.

On February 5, 2016, PCEC provided written notice to Breitburn Management of its intention terminate the ASA effective as of June 30, 2016.

For more information on potential conflicts between us and PCEC, see our Annual Report filed on Form 10-K for the year ended December 31, 2015 filed with the SEC on February 26, 2016, Part I — Item 1A "— Risk Factors" — "Risks Related to Our Structure — Certain of the directors and officers of our General Partner, including the Vice Chairman of the Board, our Chief Executive Officer, our President and other members of our senior management, own interests in PCEC, which is managed by our subsidiary, Breitburn Management. Conflicts of interest may arise between PCEC, on the one hand, and us and our unitholders, on the other hand. Our partnership agreement limits the remedies available to you in the event you have a claim relating to conflicts of interest."

Omnibus Agreement

On August 26, 2008, the Partnership entered into an Omnibus Agreement with PCEC, PCEC's general partner, PCEH, our General Partner and Breitburn Management, which sets forth certain agreements with respect to conflicts of interest.

PCEC has agreed that the Partnership has a preferential right with respect to any business opportunity with respect to either (1) any third party upstream oil and gas properties and any related midstream assets, if the fair market value of the estimated proved developed reserves related to such properties constitutes 70% or more of the fair market value of such properties and related midstream assets (as determined in good faith by the Board), or (2) any third party oil and gas properties and any related midstream assets located within one mile of any oil and gas properties and any related midstream assets that are owned by the Partnership, our General Partner or any of their subsidiaries, and in which no interest is owned by PCEH, PCEC's general partner, PCEC or any of their subsidiaries.

The Partnership has agreed that PCEC has a preferential right with respect to any business opportunity with respect to either (1) any third party upstream oil and gas properties and any related midstream assets, if the fair market value of the estimated proved developed reserves related to such properties constitutes less than 70% of the fair market value of such properties and related midstream assets (as determined in good faith by the board of directors of PCEH), or (2) any oil and gas properties and any related midstream assets located within one mile of any oil and gas properties and any related midstream assets that are owned by PCEH, PCEC's general partner, PCEC or any of their subsidiaries, and in which no interest is owned by the Partnership, our General Partner or any of their subsidiaries.

If the Partnership or PCEC is presented with a business opportunity with respect to any oil and gas properties and any related midstream assets located within one mile of any oil and gas properties that are jointly owned by the Partnership and PCEC, the Partnership or PCEC, as applicable, must give prompt written notice to the other party of such business opportunity. The Partnership and PCEC have agreed to discuss the pursuit of a joint bid for such business opportunity on the basis of their existing ownership interests, including their respective operating control, in the jointly owned properties. If the parties cannot agree on the terms upon which to proceed with a joint bid within 15 business days, then each of the Partnership and PCEC will be free to pursue an independent bid for such business opportunity. As of August 26, 2008, the properties jointly owned by the Partnership and PCEC were properties in the East Coyote and Sawtelle fields in the Los Angeles Basin in California.

The Omnibus Agreement may be terminated (1) by PCEH upon notice to the other parties upon a change of control of PCEC, (2) by our General Partner upon notice to the other parties upon a change of control of the Partnership, and (3) by either PCEH or our General Partner at such time as the Partnership and PCEC cease to be under common management or upon the termination of the ASA; provided, however, that if the ASA is terminated under certain circumstances, the Omnibus Agreement may not be terminated by PCEH until 180 days after termination of the ASA.

Transactions with EIG

Effective on April 8, 2015 (the “Closing Date”), Kurt A. Talbot was appointed as a Class III director (term expiring in 2017) of our General Partner in connection with the closing of the Partnership’s private placements of $350 million of its Series B units and $650 million of 9.25% Senior Secured Second Lien Notes due 2020 (the “Notes”). Mr. Talbot is Senior Advisor with EIG Management Company, LLC and a member of the Executive Committee of EIG Global Energy Partners, which sponsored the private equity funds that directly or indirectly own EIG Redwood Equity Aggregator, LP (“EIG Equity”) and EIG Redwood Debt Aggregator, LP (“EIG Debt ”).

Purchase of Series B Preferred Units

On the Closing Date, EIG Equity purchased 35 million Series B units from the Partnership at an issue price of $7.50 per share (an aggregate price of $262.5 million) pursuant to an amended and restated Series B unit purchase agreement with EIG Equity and the other purchasers party thereto (together with EIG Equity, the “Preferred Unit Purchasers”). On that date, the Partnership executed the Third Amended and Restated Agreement of Limited Partnership of the Partnership to establish the powers, preferences and special rights of the Series B units. Also on that date, the Partnership paid EIG Management Company, LLC (“EIG MC”), an affiliate of EIG, a transaction fee of $7 million with respect to the purchase of the Series B units.

Purchase of Notes

On the Closing Date, EIG Debt purchased $487.5 million in principal amount of the Notes from the Partnership at a purchase price of 97% of the principal amount pursuant to an amended and restated note purchase agreement with EIG Debt and the other purchasers party thereto. Also on that date, the Partnership paid EIG MC a transaction fee equal to $13 million with respect to the purchase of the Notes.

Board Representation and Standstill Agreement

On the Closing Date, the Partnership and the General Partner entered into a board representation and standstill agreement with EIG Equity (the “Board Representation and Standstill Agreement”). Pursuant to the Board Representation and Standstill Agreement, the Partnership and the General Partner agreed to permit EIG Equity to appoint a single representative, in a non-voting observer capacity, to attend all meetings of the full board of directors of the General Partner (the “Board”), subject to certain exceptions. The Partnership and the General Partner also agreed to permit EIG Equity to designate one person to serve as a director on the Board. In general, the Board observation rights and the Board designation rights terminate on the earlier of (1) the date EIG Equity and its affiliates cease to own a majority of the Series B units issued on the Closing Date (plus associated PIK Units) (except upon conversion of the Series B units) or (2) on or after the initial conversion of the Series B units, the date on which EIG Equity and its affiliates no longer own (A) common units issued in respect of any such conversions and (B) Series B units on an as-converted basis that, together, represent 7.5% or more of the outstanding common units (counting for this purpose in the denominator all outstanding Series B units as though they were outstanding common units based on the Series B Conversion Ratio (as defined in the Partnership Agreement) then in effect).

Through and including the annual meeting of unitholders to elect directors to the Board that is held in 2017, EIG Equity has agreed that, at any meeting of the unitholders or in any other circumstances upon which a vote, consent or other approval of all or some of the unitholders is sought solely with respect to the matters described below, EIG Equity will vote (or cause to be voted) or execute (or cause to be executed) consents with respect to, as applicable, all of the units owned by EIG Equity and its affiliates as of the applicable record date (1) in favor of the election of the persons named in the Partnership’s proxy statement as the Board’s nominees for election as directors, and against any other nominees and (2) in favor of the adoption of or amendment to any equity-based compensation plans presented by the Board for unitholder vote that are similar with respect to amount and types of awards for long-term incentive plans of publicly traded upstream oil and gas companies.

In addition, EIG Equity, for itself and its affiliates, has agreed to customary standstill provisions through the earlier of (1) the first anniversary of the date EIG Equity’s board observation and designation rights terminate and (2) the later of (A) the third anniversary of the Closing Date or (B) the first anniversary of the date on which both EIG Equity’s designated director has resigned from the Board and EIG Equity has permanently waived and renounced the Board observation and designation rights.

Registration Rights Agreement

On the Closing Date, the Partnership entered into a registration rights agreement ("Registration Rights Agreement") with the Preferred Unit Purchasers, including EIG Equity, relating to the registered resale of (1) the Series B units, including PIK Units, and (2) common units issuable upon conversion of the Series B units, including PIK Units. The registration statement for such registered resale was filed on June 12, 2015 and declared effective by the SEC on September 11, 2015. In certain circumstances, the Preferred Unit Purchasers will have piggyback registration rights and rights to request an underwritten offering as described in the Registration Rights Agreement. Each Preferred Unit Purchaser will cease to have registration rights under the Registration Rights Agreement on the later of the fifth anniversary of the Closing Date and the date on which the Preferred Unit Purchaser holds less than $30 million of registrable securities.

Related Party Transaction Policy and Procedures

Our General Partner has adopted a written policy for the review of transactions with related parties. The policy requires review, approval or ratification of transactions exceeding $120,000 in which the Partnership is a participant and in which a director or executive officer of our General Partner, an owner of a significant amount of our voting securities or an immediate family member of any of the foregoing persons has a direct or indirect material interest. These transactions must be reviewed for pre-approval by the Chief Executive Officer if the related party is an executive officer, by the Audit Committee if the related party is a significant unitholder or the Chief Executive Officer, by the Chairman of the Audit Committee if the related party is a director or by a member of the Audit Committee if the related party is the Chairman of the Audit Committee. Only those transactions that are in, or are not inconsistent with, the best interests of the Partnership, taking into consideration whether they are on terms comparable to those available with an unrelated third party and the related party's interest in the transaction, will be approved.

COMPENSATION DISCUSSION AND ANALYSIS

Executive Summary

This Compensation Discussion and Analysis section discusses the compensation policies and programs for the named executive officers of our General Partner during the year ended December 31, 2015, who were Halbert S. Washburn, our Chief Executive Officer, and James G. Jackson, our Executive Vice President and Chief Financial Officer, and the three next most highly paid executive officers of our General Partner: Mark L. Pease, our President and Chief Operating Officer, Gregory C. Brown, our Executive Vice President, General Counsel and Chief Administrative Officer and W. Jackson Washburn, a Senior Vice President.

In June 2014, we provided our unitholders an advisory vote to approve the compensation of our named executive officers (the "say-on-pay proposal"). At our 2014 Annual Meeting of Limited Partners, our unitholders overwhelmingly approved the compensation of our named executive officers, with over 92% of the votes cast in favor of the say-on-pay proposal. The Compensation and Governance Committee believes this affirms the unitholders' support of our approach to executive compensation, and did not make any significant changes to its approach in 2014 and 2015. The Compensation and Governance Committee will continue to consider the outcome of our say-on-pay votes when making future compensation decisions for the named executive officers. In addition, when determining how often to hold future say-on-pay proposals to approve the compensation of our named executive officers, the Board took into account the strong preference for a triennial vote expressed by our unitholders at our 2011 Annual Meeting of Limited Partners, with over 78% of the votes cast in favor of a triennial vote. Accordingly, the Board determined that we will hold a vote on the say-on-pay proposal to approve the compensation of our named executive officers every three years. Our next say-on-pay proposal vote is expected to be held at the 2017 Annual Meeting of Limited Partners.

Certain 2015 Compensation Decisions. The Compensation and Governance Committee made the following key compensation decisions with respect to our named executive officers' 2015 compensation. These and other elements of our named executive officers' 2015 compensation are discussed in further detail below. See "—Components of Compensation."

In January 2015, the Compensation and Governance Committee made grants of restricted phantom units ("RPUs") pursuant to the Partnership's 2006 Long-Term Incentive Plan (as amended, the "Long-Term Incentive Plan") to each of our named executive officers on terms substantially similar to the grants made to these executives in 2014. These grants continued to further our intent of closely aligning our executive compensation with our peers.

In January 2015, the Compensation and Governance Committee entered into amendments to the convertible phantom unit ("CPU") agreements (the "CPU Agreements") in respect of CPUs granted in 2013 and 2014 to our named executive officers under the Long-Term Incentive Plan. The amendments provide that, at vesting, CPUs will be settled in common units on a 1:1 basis and that previously credited performance distribution equivalents ("PDRs") will be forfeited. The Compensation and Governance Committee determined that these modifications were appropriate and consistent with our retention objectives for our named executive officers in 2015. No CPUs were granted to named executive officers in 2014.

In early 2016, the Compensation and Governance Committee approved cash bonuses earned in 2015 at 79% of each of Messrs. Halbert S. Washburn, Pease, Jackson, Brown and W. Jackson Washburn's 2015 target bonus opportunities , after taking into account the accomplishments and performance of management in 2015 and the overall performance of the Partnership.

2016 Compensation Decisions. In August 2015, the Compensation and Governance Committee engaged Meridian Compensation Partners, LLC ("Meridian"), a compensation consultant that the Compensation and Governance Committee believes to be independent. On January 28, 2016, based on guidance from Meridian, the Compensation and Governance Committee approved certain changes to compensatory plans and arrangements in which the named executive officers of our General Partner participate. These changes were intended to address the effect of the steep decline in commodity prices, and the related decline in the price of our common units, on the total direct compensation granted to our named executive officers and to continue to align our named executive officers' compensation with the interests of our unitholders. The value of the grants described below represent a 30% reduction of each named executive officer's target long-term incentive compensation.

Changes consisted of a new long-term incentive compensation program that, in addition to unit-settled RPUs, includes a new form of cash-settled RPUs, which represent the right to receive a cash payment equal to the fair market value of a common unit on the applicable vesting date (but in no event settled for less than $0.50 per RPU) or, at the Company's election, a number of common units equal to the number of vested RPUs. In addition, each such RPU was granted in tandem with a distribution equivalent right that remains outstanding from the grant of the RPU until the earlier to occur of its forfeiture or the payment of the underlying common unit, and which entitles the holder thereof to receive a payment of amounts equal to distributions paid in respect of the common units underlying such RPU during such period. The cash-settled RPUs generally vest in two equal installments, on June 28, 2017 and December 28, 2017, subject to the named executive officer's continued service. The cash-settled RPUs vest in full upon certain qualifying terminations of employment without "cause" for "good reason" or due to death or "disability" and upon a "change of control" (each, as defined in the Long-Term Incentive Plan or the applicable award agreement). The following table sets forth the RPUs (both cash-settled and unit-settled) granted to our named executive officers on January 28, 2016. Unit-settled RPUs granted in 2016 vest in two equal installments on June 28, 2018 and December 28, 2018, subject to the named executive office's continued service, and otherwise contain terms materially consistent with the terms of the 2015 unit-settled RPU grants described below. See "—Components of Compensation—Long-Term Incentive Plan—Restricted Phantom Units (RPUs)".

Name	Cash-Settled RPUs Granted (#)	Unit-Settled RPUs Granted (#)
Halbert S. Washburn	1,086,953	2,001,389
Mark L. Pease	529,541	975,036
James G. Jackson	390,188	718,448
Gregory C. Brown	390,188	718,448
W. Jackson Washburn	153,637	282,889

In addition, in January 2016, the Compensation and Governance Committee approved grants of discretionary cash incentive bonus awards, including discretionary cash incentive bonus awards to our named executive officers. The bonuses vest in two installments on June 28, 2016 and December 28, 2016, subject to the grantee's continued service as an employee through the applicable vesting dates. These bonuses are neither granted under, nor subject to the terms of, the Long-Term Incentive Plan or our Short-Term Incentive Plan. The following table sets forth the dollar values of the discretionary cash incentive bonus awards granted to our named executive officers in January 2016:

Name	Discretionary Cash Bonus Amount
Halbert S. Washburn	$739,127
Mark L. Pease	360,088
James G. Jackson	265,327
Gregory C. Brown	265,327
W. Jackson Washburn	104,472

2015 Business Highlights; Pay for Performance. Pay for performance is an important component of our compensation philosophy. In this regard, our executive compensation program includes annual bonuses and long-term incentive compensation that are tied to the Partnership's performance. During 2015, among other accomplishments, we successfully integrated the assets acquired in connection with the acquisition of QR, Energy, LP, a Delaware limited partnership ("QRE"). We achieved record production of 20 million barrels of oil equivalent ("Boe") which was a year over year increase of approximately 43 percent. We also controlled pre-tax lease operating expenses resulting in an 18.5% decrease in costs for the fourth quarter of 2015, as compared to the fourth quarter of 2014. We closed a $1 billion strategic investment led by EIG Global Energy Partners, which included $350 million of convertible preferred equity and $650 million of senior secured second lien notes, the net proceeds of which were used to repay borrowings under our bank credit facility. As part of that strategic investment, we were able to negotiate a one-year fixed borrowing base of $1.8 billion under our bank credit facility. The Compensation and Governance Committee took these positive accomplishments, among other considerations, into account in making compensation decisions with respect to our named executive officers' 2015 compensation.

Unitholder Interest Alignment. Our long-term incentive compensation program is intended to be strongly aligned with the long-term interests of our unitholders. We have provided our named executive officers with annual grants of RPUs since 2007, and in certain years, CPU grants, in order to align compensation with unitholder interests by encouraging retention and long-term performance. We continue to believe that linking our named executive officers' compensation to the amount and payment of distributions to our unitholders is key to aligning their interests with that of our unitholders.

Good Governance. In furtherance of our objective of implementing policies and practices that are mindful of the concerns of our unitholders, the Compensation and Governance Committee is comprised solely of independent directors and the Compensation and Governance Committee has engaged compensation consultants that it believes to be independent to provide it with advice on matters related to executive compensation from time to time.

Determination of Compensation

The Compensation and Governance Committee is responsible for reviewing the Partnership's compensation program from time to time and making recommendations to the full Board regarding any changes to the program. Grants of equity awards are approved by the Compensation and Governance Committee.

In November 2012, Hay Group, Inc. ("Hay Group") provided the Compensation and Governance Committee with a market review of our executive compensation program. Hay Group used the E&P Peer Group (as defined below) to compare 2011 base salaries, annual incentive targets and long term incentive target awards levels of certain executive officers of our General Partner. Hay Group compared the amounts and forms of our executive compensation with that of the following peer group of eighteen U.S. master limited partnerships and other exploration and production companies (the "E&P Peer Group") as set forth below.

Berry Petroleum Company	Laredo Petroleum Holding Inc.	Rosetta Resources, Inc.
Cabot Oil & Gas Corporation	Legacy Reserves LP	SM Energy Company
Comstock Resources, Inc.	Linn Energy, LLC	Stone Energy Corporation
EPL Oil & Gas Inc.	PDC Energy Inc.	Swift Energy Company
EXCO Resources, Inc.	Plains Exploration & Production Company	Vanguard Natural Resources LLC
Forest Oil Corporation	Range Resources Corporation	W&T Offshore Inc.

The criteria for inclusion in the E&P Peer Group was based on utilizing upstream, independent oil and gas exploration and production companies, ranging from approximately one-half to two times our size based on year end revenue, and with a priority on master limited partnerships. In January 2013, Hay Group provided the Compensation and Governance Committee with an updated market review of our executive compensation program.

While the Compensation and Governance Committee considered the E&P Peer Group in establishing executive compensation, the Committee did not formally benchmark total compensation or individual compensation elements against the E&P Peer Group, and the Compensation and Governance Committee does not aim to set total compensation, or any compensation element, at a specified level as compared to the companies in the E&P Peer Group.

In August 2015, the Compensation and Governance Committee engaged Meridian Compensation Partners, LLC ("Meridian"), a compensation consultant that the committee believes to be independent. Meridian was engaged to advise the committee with respect to executive compensation and to recommend, develop and design new long term incentive awards to address the steep decline in commodity prices and the related decline in the price of our Common Units, which underpin the long term incentive compensation made to our executives. As discussed in detail above, in January 2016, Meridian recommended a new long-term incentive compensation program, which, in addition to unit-settled RPUs, included grants of cash-settled RPUs and discretionary cash incentive bonus awards to our named executive officers. See "Compensation Discussion and Analysis—Executive Compensation—2016 Compensation Decisions."

Compensation Objectives

Our overall goal is to ensure that executive compensation policies are consistent with our strategic business objectives, are aligned with the interests of the unitholders and provide incentives for the attainment of these objectives. Our named executive officer compensation program includes three components:

- base salary, which is intended to provide a stable annual salary at a level consistent with competitive market practice, individual performance and scope of responsibility;
- variable short-term incentive cash bonuses, which link compensation to our performance, and the performance of the individual executive, over the course of the year; and
- variable long-term equity-linked awards, which encourage actions to maximize long-term unitholder value.

The relative proportion of total compensation we pay or award for each individual component of compensation (base, variable short-term cash bonus or long-term equity-linked awards) varies for each named executive officer based on the executive's level in the organization. The executive's level correlates with the executive's ability to impact business results through the executive's performance and leadership role. At higher levels of the organization, executive officers have a greater impact on achievement of the business strategy and overall business performance. Therefore, certain executive officers have a higher proportion of their total compensation delivered through variable short-term cash bonuses and long-term equity-linked awards. Our philosophy is to make a greater proportion of an executive's compensation comprised of performance-based variable short-term cash bonuses and long-term equity-linked awards so that the executive is well-rewarded if we perform well over time. Our policy is to fix at the beginning of each year the target amount of variable short-term bonus and equity-linked awards that will be provided to the named executive officer during the year as a percentage of the named executive officer's base salary. Base salary, benefits and severance arrangements are fixed and not directly linked to performance targets. See "— Components of Compensation."

Components of Compensation

Base Salary

Our policy is to position base executive salaries at levels that we believe are comparable to salaries provided to other executive officers in our market, with consideration to the scope of an individual's responsibilities and performance. In 2015, the Compensation and Governance Committee did not increase named executive officer salaries from those in effect in 2014.

The annual base salaries of our named executive officers for 2014 and 2015 are noted below:

		Annual Base Salary	
Name	**Position in 2015**	**2015**	**2014**
Halbert S. Washburn	Chief Executive Officer	$ 676,000	$ 676,000
Mark L. Pease	President and Chief Operating Officer	494,000	494,000
James G. Jackson	Executive Vice President and Chief Financial Officer	416,000	416,000
Gregory C. Brown	Executive Vice President, General Counsel, and Chief Administrative Officer	416,000	416,000
W. Jackson Washburn	Senior Vice President	327,600	327,600

Short-Term Incentive Plan (STIP) — Annual Bonuses

We provide short-term incentive awards in the form of discretionary annual cash bonuses to eligible employees of Breitburn Management, including the named executive officers. The STIP is usually paid during the first quarter of the year following the performance year and is designed to focus employees on our operating and financial performance by linking their annual award payment to Partnership and individual performance for the prior year. The target bonus opportunities were set at levels recommended by Hay Group in November 2012, which were intended to place the named executive officers' target cash compensation and target direct compensation within the 50^{th} to 75^{th} percentile of the E&P Peer Group, with opportunities for higher total compensation based on outstanding short- and long-term results. The following table sets forth each named executive officer's target and maximum award opportunities (as a percentage of base salary) for 2015:

	2015	
Name	**Target Award**	**Maximum Award**
Halbert S. Washburn	100%	200%
Mark L. Pease	90%	180%
James G. Jackson	80%	160%
Gregory C. Brown	80%	160%
W. Jackson Washburn	50%	100%

In determining bonus payouts for 2015, the Compensation and Governance Committee evaluated the Partnership's performance and considered the following factors: (1) we successfully integrated the assets acquired in connection with the acquisition of QRE; (2) we achieved record production of 20 million Boe which was a year over year increase of approximately 43 percent; (3) we controlled pre-tax lease operating expenses resulting in an 18.5% decrease in costs for the fourth quarter of 2015, as compared to the fourth quarter of 2014; (4) we closed a $1 billion strategic investment led by EIG Global Energy Partners, which included $350 million of convertible preferred equity and $650 million of senior secured second lien notes, the net proceeds of which were used to repay borrowings under our bank credit facility; and (5) we negotiated a one-year fixed borrowing base of $1.8 billion under our bank credit facility. The Compensation and Governance Committee's evaluation of the named executive officers' performance was based on both certain operating and financial performance criteria established by the Board at the beginning of the year and on a subjective assessment of the individual executive's performance. The Compensation and Governance Committee reviewed the actual results of the Partnership during 2015 against core strategic goals set by the Board at the beginning of the year. These goals included targets for generating distributable cash flow, maintaining distributions, maintaining a maximum debt leverage ratio, staying at or below an average level of bank debt, completion of certain general and administrative expense reductions, completion of the integration of QRE and its assets, execution of $1 billion capital raise to reduce borrowings under the bank credit facility and a measure of certain key operating goals of the Partnership. The Compensation and Governance Committee determined that, during 2015, the Partnership met or exceeded the core strategic goals with respect to operating performance, general and administrative expense reductions, integration of QRE, and the execution of the $1 billion capital raise, but did not meet the goals related to the maintenance of distributions, maintaining a debt leverage ratio, staying at or below an average level of bank debt and the generation of distributable cash flow. The core strategic operating goal is a combined measure resulting from a comparison of the following criteria to amounts budgeted for these items: oil and gas production, lease operating expenses, capital efficiency, general and administrative expense, safety and distributable cash flow per common unit. With respect to this operating goal, the Compensation and Governance Committee determined that, in 2015, the Partnership exceeded budgeted performance for lease operating expenses and met its budgeted performance for oil and gas production and safety. The Compensation and Governance Committee determined that actual performance for capital efficiency, general and administrative expense and distributable cash flow were below targeted levels. The Compensation and Governance Committee also subjectively reviewed the performance of our General Partner's named executive officers during the year. Although the Partnership on an overall basis achieved 105% of its budgeted core strategic operating goal, the Committee after taking into account the state of the industry and the Partnership, used its discretion to lower bonuses to 79% of each executive's target award. Based on the Committee's evaluation of the Partnership's performance described above, our named executive officers' 2015 STIP annual bonuses were determined to have been earned as follows:

Name	2015 Bonus Award (as a % of Target Award)
Halbert S. Washburn	79%
Mark L. Pease	79%
James G. Jackson	79%
Gregory C. Brown	79%
W. Jackson Washburn	79%

It should be noted that only a portion of the STIP for the named executive officers is paid by the Partnership. The Partnership paid 75% of the calculated STIP amount to Messrs. Halbert S. Washburn and Jackson, 80% of the calculated STIP amount to Mr. Pease, 73% of the calculated STIP amount to Mr. Brown and 95% of the calculated STIP amount to Mr. W. Jackson Washburn, because the executive officers also perform work for PCEC. PCEC is responsible for paying STIP bonuses attributable to work done on behalf of PCEC based upon the separate performance of PCEC. The bonus amounts awarded for 2015 are included in the "Summary Compensation Table" below.

Long-Term Incentive Plan

The Long-Term Incentive Plan provides financial incentives to the named executive officers through grants of unit and unit linked awards, including RPUs and CPUs. The Long-Term Incentive Plan is designed to focus its participants on our operating and financial performance by linking the value of awards to distributions to unitholders and other Partnership and individual results.

In 2015, certain of the senior executive officers of our General Partner, including the named executive officers, received new grants of RPUs. The grant amounts were established in accordance with the target long-term incentive values as a percentage of base salary that were recommended by Hay Group in January 2013 as follows:

Name	Long-Term Incentive Values as a Percentage of Base Salary
Halbert S. Washburn	600%
Mark L. Pease	400%
James G. Jackson	350%
Gregory C. Brown	350%
W. Jackson Washburn	175%

The Compensation and Governance Committee approves grants of RPUs to our named executive officers on an annual basis and, in past years, grants of CPUs to certain of our named executive officers. RPUs granted prior to 2016 are generally scheduled to vest on an annual basis over a three year period, while the CPU grants are scheduled to vest at the end of a three year period. In 2015, no new grants of CPUs were made to our named executive officers, because the Compensation and Governance Committee did not believe that such grants would be effective as long-term incentive compensation, given the low commodity price environment and the Compensation and Governance Committee's retention objectives for our named executive officers.

Restricted Phantom Units (RPUs)

RPUs are phantom equity awards that, to the extent vested, represent the right to receive actual common units upon specified payment events. RPUs generally vest in three equal, annual installments on each anniversary of the vesting commencement date of the award. In addition, RPUs are generally subject to accelerated vesting in full upon the earlier occurrence, during the grantee's employment, of a "change in control" or upon the grantee's termination due to death or "disability," termination without "cause" or, for certain grantees, termination for "good reason" (as defined in the holder's employment agreement, if applicable). Under the Long-Term Incentive Plan, a "change in control" is generally defined as the occurrence of any one of the following: (a) the acquisition by any person, other than an affiliate, of more than 50% of the combined voting power of the equity interests in Breitburn Management, our General Partner or us; (b) the approval by our limited partners, in one or a series of transactions, of a plan of complete liquidation; (c) the sale or other disposition by either our General Partner or us of all or substantially all of our assets to any person other than an affiliate; (d) a transaction resulting in a person other than our General Partner becoming the general partner; or (e) any time at which our "continuing directors" cease to constitute a majority of the Board. If an RPU vests on an annual vesting date or in connection with a termination of employment, the grantee will receive payment of the underlying common units within sixty days after such vesting date. If an RPU vests in connection with a change in control, then the grantee will receive payment of the underlying common units upon the earlier to occur of the annual vesting date that would have applied absent the change in control or the grantee's termination of employment. Amounts payable in the event of a termination of the grantee's employment are subject to a delay of up to six months to the extent required to comply with Section 409A of the Internal Revenue Code of 1986, as amended (the "Code"). In addition, each RPU is granted in tandem with a distribution equivalent right that will remain outstanding from the grant of the RPU until the earlier to occur of its forfeiture or the payment of the underlying unit, and which entitles the grantee to receive payment of amounts equal to distributions paid to each holder of a common unit during such period. RPUs that do not vest for any reason are forfeited upon a grantee's termination of employment. In January 2015, the Compensation and Governance Committee approved its annual grants of RPUs to our named executive officers. The grant amounts were established in accordance with the grant guidelines that were recommended by Hay Group in January 2013.

Convertible Phantom Units (CPUs)

In January 2014, we granted CPUs to certain named executive officers. CPUs are scheduled to fully vest on December 28, 2016 or, if earlier, vest on a pro rata basis in the event of the death or "disability" of the grantee or his termination without "cause" or for "good reason" (as each such term is defined in the applicable award or employment agreement). Unvested CPUs are forfeited in the event that the grantee ceases to remain in the service of Breitburn Management. Under the CPU Agreements, each CPU entitled its holder to receive (a) a number of our common units at the time of vesting equal to the number of "common unit equivalents" ("CUEs") underlying the CPU at vesting, and (b) PDRs on common units during the vesting period based on the number of CUEs underlying the CPU at the time of such distribution. Each PDR entitles the executive to additional CPUs with a value equal to the amount of distributions paid on each common unit to unitholders. The number of CUEs underlying each CPU at vesting is calculated based upon the annualized amount of distributions made per common unit preceding the vesting date. Originally, the number of CUEs per CPU could be reduced over the three-year life of the agreement to a minimum of zero or multiplied by a maximum of 4.768 times (the "multiplier") based on the Partnership's distribution levels. However, the multiplier was fixed through an amendment to the CPU Agreements as described more fully below.

The number of common units into which CPUs are converted upon vesting is subject to a clawback provision intended to permit us to recoup excess distributions paid to the grantee during the term of the award. The clawback provision is applicable if the amount of distributions that would have been paid to the grantee during the term of the award (based on the number of common units issued at vesting) is less than the amount of distributions actually paid to the grantee during the term of the award (based on the number of CUEs used to determine the amount of distributions received during the term of the award). The clawback would be effected by deducting a number of common units issued upon vesting with a value equal to the excess distributions (based upon the value of the common unit on the NASDAQ Global Select Market, if applicable on the vesting date).

In January 2015, we entered into amendments to the CPU Agreements, including the CPU Agreements with each of our named executive officers. The amendments to the CPU Agreements limit the multiplier to 1, commencing with the date of the amendment. As a result, at vesting, CPUs for each award will convert to common units on a 1:1 basis. In addition, the amendments provide for the forfeiture from the date of the grant to the date of the amendment of previously credited PDRs to each named executive officer. No other modifications were made to the CPU Agreements under the amendments. The Compensation and Governance Committee determined that these modifications were appropriate and consistent with its retention objectives for our named executive officers in 2015. CPUs were not granted to any named executive officers in 2015. All 2015 long-term incentive compensation grants to the named executive officers were in the form of RPUs.

Employment Agreements

On December 30, 2010, Breitburn Management, our General Partner and we entered into separate Amended and Restated Employment Agreements ("Employment Agreements") with each of Messrs. Halbert S. Washburn, Pease, Jackson and Brown. Each Employment Agreement is for a term that commenced on December 30, 2010 and initially expired on January 1, 2014, with automatic one-year renewal terms unless either the Employer (as defined in the Employment Agreements) or the executive officer gives written notice of termination 90 days prior to the end of the term. Each Employment Agreement provides for an annual salary which may be increased (but not decreased) at the discretion of the Employer.

Under the terms of the Employment Agreements, each of the executive officers is also eligible to participate in the STIP, our Long-Term Incentive Plan and other benefit plans and fringe benefits maintained or provided by the Employer. During their respective employment periods, the executive officers are entitled to prompt reimbursement for up to $1,000 per month for actual expenses associated with the lease or purchase of an automobile, in addition to the payment of maintenance and operation expenses for such automobile. The Employment Agreements provide that the Employer may terminate any of the executive officers with or without cause or in the case of an executive officer's disability. Each executive officer may terminate his Employment Agreement with or without good reason.

"Cause" is generally defined as (a) the willful and continued failure of the executive officer to perform substantially his duties (other than due to physical or mental illness) after a written demand for substantial performance approved by a majority vote of the Board and a reasonable period for cure of not more than twenty business days, (b) the willful engaging by the executive officer in illegal conduct or gross misconduct, which is materially and demonstrably injurious to us or any of our affiliates, (c) any act of fraud, or material embezzlement or material theft in connection with the executive officer's duties or in the course of the executive officer's employment, or (d) the executive officer's admission in any court, conviction, or plea of nolo contendere of a felony involving moral turpitude, fraud or material embezzlement, material theft or material misrepresentation against or affecting us or any of our affiliates. However, no act or failure to act by the executive officer shall be considered "willful" unless it is done, or omitted to be done, by the executive officer in bad faith or without reasonable belief that the executive officer's action or omission was in our best interests or in the best interests of any of our affiliates.

"Good reason" is generally defined as (a) a material diminution in the executive officer's base salary, (b) a material diminution in the executive officer's authority, duties or responsibilities, (c) a material diminution in the authority, duties or responsibilities of the supervisor to whom the executive officer is required to report, (d) a material diminution in the budget over which the executive officer retains authority, (e) a material change in the geographic location at which the executive officer must perform services under the Employment Agreement, or (f) any other action or inaction that constitutes a material breach by the employer of the Employment Agreement.

An executive officer's resignation, however, shall only constitute resignation for good reason if (1) the executive officer provides the Employer with written notice setting forth the specific facts or circumstances constituting good reason within thirty days after the initial existence of such facts or circumstances, (2) the Employer fails to cure such facts or circumstances within thirty days after receipt of such written notice, and (3) the date of the executive officer's "separation from service" (as defined in the respective Employment Agreement) occurs no later than seventy-five days after the later of (i) the initial occurrence of the event constituting "good reason" or (ii) the date the executive officer learns or reasonably should have learned of such event.

If the Employer terminates an executive officer without cause (other than in the case of the executive officer's death or disability), or the executive officer terminates his employment for good reason, in either case in a manner that constitutes a "separation from service" within the meaning of Section 409A of the Code, then the executive officer will be entitled to:

- a lump-sum payment equal to the sum of the executive officer's accrued but unpaid base salary, vacation pay and unreimbursed business expenses and other accrued but unpaid benefits (referred to as the "accrued obligations"); and
- provided that the executive officer executes, delivers and does not revoke a general release and waiver of claims within 45 days of his termination:

(a) provided that the executive officer's termination occurs prior to the date on which he reaches age 70, a payment equal to 1.5 times (or, in the case of Mr. Halbert S. Washburn only, a payment equal to 2.0 times) the sum of his base salary, plus his "target bonus" (as defined in the respective Employment Agreement) as in effect immediately prior to the date of determination,

(b) up to an eighteen month (or, in the case of Mr. Halbert S. Washburn only, up to a twenty-four month) continuation of certain medical, prescription and dental benefits for the executive and his eligible dependents (until he becomes eligible to receive benefits under another employer-provided group health plan),

(c) any unpaid annual bonus in respect of any calendar year that ends on or before the date of termination,

(d) to the extent not previously vested and converted into common units or forfeited, certain equity-based awards, including RPUs, held by the executive officer will vest and convert into common units as described under "— Long-Term Incentive Plan," and

(e) a pro-rated bonus equal to the product of (i) his "target bonus" and (ii) a fraction, the numerator of which is the number of days in the applicable year through the date of termination and the denominator of which is 365 (the "pro-rata bonus").

In addition, if, during the period beginning 60 days prior to and ending two years immediately following a "change in control" (as defined in the Employment Agreements), either the Employer terminates the executive officer's employment without cause, or the executive officer terminates his employment for good reason, in either case in a manner that constitutes a separation from service, then the executive officer will be entitled to the severance payments and benefits described above, except that the severance multiple described in clause (a) will be equal to 2.5 (instead of 1.5) (or, in the case of Mr. Halbert S. Washburn only, equal to 3.0 (instead of 2.0)). If a change in control occurs during the term of the Employment Agreement, certain equity-based awards, including RPUs, held by the executive officer, to the extent not previously vested and converted into common units, will vest in full upon such change in control and be converted into common units as described under "— Long-Term Incentive Plan."

If an executive officer incurs a separation from service because the Employer terminates him for cause, or an executive officer terminates his employment for other than good reason, the Employer will pay him his accrued obligations, and any outstanding equity awards (including RPUs and CPUs held by the executive officer) will be treated in accordance with the terms of the governing plan and award agreement.

If the executive officer incurs a separation from service by reason of his death or disability, then he will be entitled to:

- the accrued obligations; and
- subject to the executive officer's (or his estate's) execution, delivery and non-revocation of a general release and waiver of claims within forty-five days of his separation from service,

(a) up to an eighteen month (or, in the case of Mr. Halbert S. Washburn only, up to a twenty-four month) continuation of certain medical, prescription and dental benefits for the executive and his eligible dependents,

(b) any unpaid annual bonus in respect of any calendar year that ends on or before the date of termination,

(c) to the extent not previously vested and converted into common units or forfeited, certain equity-based awards, including RPUs, held by the executive officer will vest and convert into common units as described under "— Long-Term Incentive Plan," and

(d) his pro-rata bonus.

If the Employer does not renew the Employment Agreement of an executive officer, such non-renewal will be treated as a termination of the executive officer's employment by the Employer without cause. In the event that an executive officer elects not to renew his Employment Agreement and incurs a separation from service as a result, he will be entitled to his accrued obligations and his outstanding equity awards, including, without limitation, the RPUs and the CPUs, shall be treated in accordance with the terms of the governing plan and award agreement. The executive officer's election not to renew his Employment Agreement shall be deemed to constitute a termination by the executive officer without good reason.

The Employment Agreements also provide that to the extent that the board of directors of the Employer determines that any compensation or benefits payable under the agreements may not be compliant with or exempt from Section 409A of the Code, the board and the executive officer will cooperate and work together in good faith to timely amend the agreements to comply with such section or an exemption therefrom. Specifically as to Mr. Halbert S. Washburn, if the executive nonetheless becomes subject to the additional tax under Section 409A of the Code with respect to any payment under his Employment Agreement, the Employer will pay the executive officer an additional lump sum cash amount to put him in the same net after-tax position he would have been in had no such tax been paid.

Each Employment Agreement provides that, for two years after termination, each executive officer must comply with certain non-solicitation provisions.

Each Employment Agreement also provides that the Employer will indemnify the executive officers to the fullest extent permitted under law for certain claims made against them while in office and for at least six years after the date of termination and, in all events, until the expiration of the applicable statute of limitations with respect to acts or omissions which occurred prior to the executive officer's cessation of employment with the Employer. Mr. Brown's Employment Agreement, in addition to the foregoing, provides for the maintenance by the Employer of liability insurance coverage for attorneys' errors and omissions on Mr. Brown's behalf, with Mr. Brown as the named insured.

401(k) Plan

The Breitburn Management Company 401(k) Plan is a defined contribution plan that also qualifies as a 401(k) plan under the Code. The contributions to the plan are made by us for each of the named executive officers on the same terms as applicable to all other employees. Under the 401(k) plan, we make a matching contribution to the plan equal to 50% of eligible participants', including the named executive officers', before-tax contributions and after-tax contributions — up to a maximum of 8% of the participant's gross compensation, subject to Code limits on the maximum amount of pay that may be recognized. A participant annually vests in 20% of the employer match portion of his or her contribution to the 401(k) plan after the participant completes each of his or her first five years of service or, if earlier, the participant reaches age 65, becomes permanently and totally disabled or dies. If a participant's service terminates before he or she is vested, the participant will forfeit the employer match and any earnings thereon.

Perquisites and Other Elements of Compensation

In 2015, we provided limited perquisites to the named executive officers consisting of (i) a car allowance or use of a company car, and (ii) a city, athletic or dining club membership. We provide a car allowance or use of a company car in recognition of the named executive officers' need to fulfill their job responsibilities. We believe that providing this benefit, as well as a city, athletic or dining club membership, enhances the competitiveness of the named executive officers' compensation packages at a limited marginal cost to us.

Equity Ownership Guidelines

On January 27, 2015, the Board adopted equity ownership guidelines for the General Partner's non-employee directors and executive officers to further align the interests of these directors and officers with the interests of unitholders. The guidelines specify the minimum amount of equity that must be held by the earlier of January 27, 2020 and within five years of becoming a director or officer of the General Partner. If an individual fails to satisfy the equity ownership requirements, he or she will be required to retain 100% of any after-tax Common Units acquired through the vesting of any CPUs and RPUs until the requirement is met. In calculating equity ownership in the Partnership, the following sources may be included: (a) Common Units purchased on the open market; (b) Common Units held in individual brokerage accounts; (c) Common Units held in trust, either jointly with, or separately from, spouse and/or children; (d) Common Units obtained through the Partnership's equity compensation program, including any Common Units subject to deferred delivery (but not forfeiture); and (e) unvested RPUs subject to time-based vesting only. The following table lists the specific equity ownership requirements:

Title	Minimum Equity Requirement
Chief Executive Officer	5x annual base salary
President and Executive Vice Presidents	4x annual base salary
Senior Vice Presidents	3x annual base salary
Directors	3x annual retainer

Tax and Accounting Considerations

As a general matter, the Compensation and Governance Committee takes into account the various tax and accounting implications of the compensation vehicles employed by our General Partner.

Section 409A

Section 409A of the Code requires that "nonqualified deferred compensation" be deferred and paid under plans or arrangements that satisfy the requirements of the statute with respect to the timing of deferral elections, timing of payments and certain other matters. Failure to satisfy these requirements can expose employees and other service providers to accelerated income tax liabilities and penalty taxes and interest on their vested compensation under such plans. Accordingly, as a general matter, we endeavor to design and administer our compensation and benefits plans and programs for all of our employees and other service providers, including the named executive officers, either without any deferred compensation component, so that they are either exempt from Section 409A, or in a manner that satisfies the requirements of Section 409A.

ASC Topic 718

Accounting Standards Codification Topic 718, Compensation — Stock Compensation ("ASC 718") requires us to recognize an expense for the fair value of equity-based compensation awards. Grants of unit-based compensation either settled in Common Units or cash are accounted for under ASC 718. The Compensation and Governance Committee regularly considers the accounting implications of significant compensation decisions, especially in connection with decisions that relate to equity compensation awards. As accounting standards change, we may revise certain programs to appropriately align the cost of our unit-based awards with our overall executive compensation philosophy and objectives.

Section 162(m)

We and our General Partner are, respectively, public and private limited partnerships, and are subject to taxes other than federal and state corporate income tax. Accordingly, we have determined that Section 162(m) of the Code, which limits tax deductions relating to executive compensation otherwise available to entities taxed as corporations, is not applicable to either us or our General Partner. If it is later determined that compensation paid by us or our General Partner to our named executive officers is subject to Section 162(m) of the Code, then this could result in an increase to our income subject to federal income tax.

COMPENSATION COMMITTEE REPORT

The Compensation and Governance Committee has reviewed and discussed the foregoing Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management. Based on our review and discussion with management, we have recommended to the Board that the Compensation Discussion and Analysis be included in the Partnership's proxy statement and, through incorporation by reference from this proxy statement, its Annual Report on Form 10-K for the year ended December 31, 2015.

The Compensation Committee:
David B. Kilpatrick, Chairman
John R. Butler, Jr.
Gregory J. Moroney
Charles S. Weiss

The foregoing Compensation Committee Report does not constitute soliciting materials and shall not be deemed filed or incorporated by reference into any other filing by the Partnership with the SEC, except to the extent specifically incorporated by reference.

COMPENSATION OF DIRECTORS AND EXECUTIVE OFFICERS

Executive Compensation Tables

The following tables and related discussion describes compensation information for each of our named executive officers for services performed for us and our subsidiaries in all capacities for the years ended December 31, 2013, 2014 and 2015.

All of our employees, including our General Partner's executive officers, are employees of Breitburn Management. We are responsible for all of the compensation paid by Breitburn Management to the named executive officers, subject to PCEC's payment obligations to Breitburn Management under the ASA between the parties. For a further discussion regarding this allocation methodology, see "—Certain Relationships and Related Transactions—Administrative Services Agreement."

Summary Compensation Table

The following table shows the compensation information for each of our named executive officers for services rendered in all capacities to us and our subsidiaries for the years ended December 31, 2013, 2014 and 2015.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(2)	Stock Awards ($)(3)	All Other Compensation ($)(4)	Total ($)
Halbert S. Washburn	2015	676,000	399,263	4,056,002	615,543	5,746,808
Chief Executive Officer	2014	667,000	329,550	4,877,391	528,658	6,402,599
	2013	638,642	243,750	4,463,830	707,280	6,053,502
Mark L. Pease	2015	494,000	280,098	1,976,003	317,929	3,068,029
President and Chief	2014	487,423	231,192	2,376,162	272,897	3,367,674
Operating Officer(5)	2013	466,346	160,313	2,174,702	354,695	3,156,056
James G. Jackson	2015	416,000	191,318	1,455,999	242,854	2,306,171
Chief Financial Officer	2014	410,462	162,240	1,750,865	224,420	2,547,987
	2013	395,385	120,000	1,602,410	300,074	2,417,869
Gregory C. Brown	2015	416,000	196,560	1,455,999	243,310	2,311,869
General Counsel	2014	410,462	157,914	1,750,865	220,603	2,539,844
	2013	395,385	116,800	1,602,410	296,799	2,411,394
W. Jackson Washburn(5)	2015	327,600	122,543	573,298	124,128	1,147,569
Senior Vice President						

(1) For each of the named executive officers, the dollar values shown in the "Salary" column include the base salary amounts paid to the named executive officer in the applicable year. We are responsible for all of the named executive officers' salaries, subject to PCEC's payment obligations to Breitburn Management under the ASA between the parties.

(2) For each of the named executive officers, the dollar values shown in the "Bonus" column include the discretionary cash bonuses paid for services rendered in the applicable year to us. With respect to 2013, 2014 and 2015, each of PCEC and the Partnership separately paid the named executive officers bonuses for services rendered in the applicable year (i.e., no allocation was required). For a further description of the STIP and individual awards, see "— Compensation Discussion and Analysis — Components of Compensation — Short-Term Incentive Plan (STIP) — Annual Bonuses."

(3) In accordance with ASC 718 the dollar values shown in the "Stock Awards" column represent the grant date fair value of RPU and CPU grants under the Long-Term Incentive Plan during the respective year for Messrs. Halbert S. Washburn, Pease, Jackson, Brown and W. Jackson Washburn. The grant date fair value of each RPU and CPU is based on the closing price of a common unit on the date of grant, which was $20.98 on January 28, 2013, $20.29 on January 29, 2014, and $6.56 on January 26, 2015. For a further discussion of the Long-Term Incentive Plan and the RPUs and CPUs granted thereunder, see "— Compensation Discussion and Analysis — Components of Compensation — Long-Term Incentive Plan." For additional information on the valuation assumptions and methodology used to determined the amounts set forth above for 2015, refer to Note 18 to the Partnership's consolidated financial statements for the year ended December 31, 2015, included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2015.

(4) For 2015, the dollar amount shown for each of the named executive officers includes employer matching contributions to our 401(k) plan made by us of $21,200 for each of Messrs. Halbert S. Washburn, Pease and Brown and $20,800 for Messrs. Jackson and W. Jackson Washburn. Such dollar amounts also include distributions paid by us with respect to outstanding RPUs and CPUs held by certain of the named executive officers of $572,383 for Mr. Halbert S. Washburn, $267,607 for Mr. Pease, $197,184 for Mr. Jackson, $197,184 for Mr. Brown and $77,642 for Mr. W. Jackson Washburn. The perquisites and personal benefits for the named executive officers in respect of fiscal year 2015 are:

Named Executive Officer	Year	Car Allowance or Company Car	Club Membership Dues	Paid Parking Fees
Halbert S. Washburn	2015	$ 12,000	$ 5,580	$ 4,380
Mark L. Pease	2015	10,528	14,874	3,720
James G. Jackson	2015	10,290	10,200	4,380
Gregory C. Brown	2015	11,966	8,580	4,380
W. Jackson Washburn	2015	13,236	8,070	4,380

(5) Mr. W. Jackson Washburn was not a named executive officer in 2013 and 2014, and therefore, his compensation for those years is not shown in this table.

Grants of Plan-Based Awards in 2015

The following table sets forth summary information regarding all grants of equity-linked plan-based awards made to our named executive officers by us for 2015:

Name	Grant Date	All Other Stock Awards: Number of Units (#)[(1)]	Grant Date Fair Market Value of Stock and Option Awards[(2)]
Halbert S. Washburn	1/26/2015	618,293	$ 4,056,002
Mark L. Pease	1/26/2015	301,220	1,976,003
James G. Jackson	1/26/2015	221,951	1,455,999
Gregory C. Brown	1/26/2015	221,951	1,455,999
W. Jackson Washburn	1/26/2015	87,393	573,298

(1) RPU awards granted to each of the named executive officers were approved by the Compensation and Governance Committee on January 26, 2015. These RPUs vest over three years in three equal installments on each December 28th following January 1, 2015 or vest in full earlier in the event of the death or "disability" of the grantee, his termination without "cause" or for "good reason" (in the case of "good reason," only for those named executive officers with employment agreements) or a "change in control" (as each such term is defined in the applicable award agreement). Unvested RPUs otherwise are forfeited in the event that the grantee ceases to remain in the service of Breitburn Management. Upon vesting, each RPU will be paid in the form of one common unit. A holder of an RPU is entitled to receive payments equal to the amount of distributions made by us with respect to each of our common units during the term of the award. For a further description of the Long-Term Incentive Plan and the RPUs granted thereunder, please see "Compensation Discussion and Analysis — Components of Compensation — Long-Term Incentive Plan."

(2) In accordance with ASC 718, the amounts shown represent the grant date fair value of the RPUs for each named executive officer for Messrs. Halbert S. Washburn, Pease, Jackson and Brown. The grant date fair value of each RPU is based on the closing price of a common unit on the date of grant. For a further discussion of the Long-Term Incentive Plan and the RPUs granted thereunder, see "— Compensation Discussion and Analysis — Components of Compensation — Long-Term Incentive Plan." For additional information on the valuation assumptions and methodology used to determine these amounts, refer to Note 18 to the Partnership's consolidated financial statements for the year ended December 31, 2015, included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2015.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

A discussion of 2015 compensation, including salaries, bonuses and equity-linked awards is included in "— Compensation Discussion and Analysis."

Outstanding Equity Awards at 2015 Fiscal Year End

The following table sets forth summary information regarding our outstanding equity-linked awards held by each of our named executive officers at December 31, 2015:

	Stock Awards		
Name	Number of Units of Stock Equivalents That Have Not Vested (#)		Market Value of Units of Stock Equivalents That Have Not Vested(1)
Halbert S. Washburn	412,169	(2)(3)	$ 276,171
	42,956	(2)(4)	28,781
	136,069	(5)	91,166
Mark L. Pease	200,814	(2)(3)	134,545
	19,519	(2)(4)	13,078
	66,290	(5)	44,414
James G. Jackson	147,968	(2)(3)	99,139
	14,382	(2)(4)	9,636
	48,845	(5)	32,726
Gregory C. Brown	147,968	(2)(3)	99,139
	14,382	(2)(4)	9,636
	48,845	(5)	32,726
W. Jackson Washburn	58,262	(2)(3)	39,036
	5,663	(2)(4)	3,794
	19,234	(5)	12,887

(1) Represents a dollar amount equal to the product of the closing price of a common unit on December 31, 2015 ($0.67) multiplied by the number of RPUs and CPUs under the Long-Term Incentive Plan held by named executive officers that have not vested. Pursuant to amendments to the CPU Agreements effected in 2015, such amount assumes that 1.00 CUE underlies each CPU. See "—Compensation Discussion and Analysis—Components of Compensation—Convertible Phantom Units (CPUs)."

(2) RPUs vest in three equal annual installments on each December 28th following the grant date, or vest in full earlier in the event of the death or "disability" of the grantee, his or her termination without "cause" or for "good reason" or a "change in control" (as each such term is defined in the applicable award agreement). Unvested RPUs otherwise are forfeited in the event that the grantee ceases to remain in the service of Breitburn

Management. Upon vesting, each RPU will be paid in the form of one common unit. A holder of a RPU is entitled to participate in the amount of distributions made by us with respect to each of our common units during the term of the award. For a further description of the Long-Term Incentive Plan and the RPUs granted thereunder, see "Compensation Discussion and Analysis—Components of Compensation—Long-Term Incentive Plan."

(3) Represents the number of RPUs granted to Messrs. Halbert S. Washburn, Pease, Jackson, Brown and W. Jackson Washburn under the Long-Term Incentive Plan on January 26, 2015.

(4) Represents the number of RPUs granted to Messrs. Halbert S. Washburn, Pease, Jackson, Brown and W. Jackson Washburn under the Long-Term Incentive Plan on January 29, 2014.

(5) Represents the number of CPUs granted in 2014 and held by Messrs. Halbert S. Washburn, Pease, Jackson, Brown and W. Jackson Washburn (including any distributions reinvested in additional CPUs since the grant date through December 31, 2015). CPUs vest fully on December 28, 2016 or vest on a pro rata basis in the event of the death or "disability" of the grantee or his termination without "cause" or for "good reason" (as each such term is defined in the applicable award or employment agreement).

Option Exercises and Stock Vested

The following table summarizes the vesting of RPUs and CPUs held by our named executive officers during 2015. No other unit-linked awards vested or were exercised during 2015.

2015 Option Exercises and Stock Vested

	Stock Awards	
Name	**Number of Shares Acquired on Vesting (#)(1)**	**Value Realized on Vesting(2)**
Halbert S. Washburn	408,714	$ 290,841
Mark L. Pease	195,875	139,385
James G. Jackson	144,330	102,705
Gregory C. Brown	144,330	102,705
W. Jackson Washburn	59,041	42,014

(1) Represents the vesting of RPUs granted to Messrs. Halbert S. Washburn, Pease, Jackson, Brown and W. Jackson Washburn under the Long-Term Incentive Plan on January 28, 2013, January 29, 2014 and January 26, 2015, which vest in three equal installments on each December 28th following the grant date, respectively. Also represents the vesting of CPUs granted to each of these named executive officers in 2013, which vested in full on December 28, 2015. The number of common units shown in this column includes units that were withheld to satisfy tax obligations.

(2) Amounts are calculated by multiplying the number of underlying units vested by the closing price of our common units on the date of vesting.

Nonqualified Deferred Compensation in 2015

In 2014, our named executive officers were offered the opportunity to defer a portion of their 2014 RPU grants. Mr. Halbert S. Washburn elected to defer 25% of his 2014 RPU grant. The terms of the award agreement for the deferred portion of his 2014 RPU grant provides for the same vesting as the non-deferred RPUs, but payment in common units is deferred until the earliest to occur of the following dates: December 28, 2025; the participant's death and the participant's Separation from Service (as defined in the Plan). In addition, each RPU is granted in tandem with a distribution equivalent right that will remain outstanding from the grant of the RPU until the earlier to occur of its forfeiture or the payment of the underlying unit, and which entitles the grantee to receive additional RPUs equal to distributions paid to each holder of a common unit during such period.

Name	Executive Contributions in Last Fiscal Year	Executive Contributions in Last Fiscal Year	Aggregate Earnings (Losses) in Last Fiscal Year	Aggregate Withdrawals/ Distributions	Aggregate Balance at Last Fiscal Year-End
(a)	(b)	(c)	(d)	(e)	(f)
Halbert S. Washburn......					
2013 Grant	$ —	$ 76,974 (1)	$ (69,628) (2)	$ —	$ 7,347 (3)
2014 Grant	—	78,687 (1)	(71,177) (2)	—	7,510 (3)

(1) Amount shown in Column (c) represents the fair market value of 22,174 common units underlying deferred RPUs that vested during 2014 (relating to deferred RPUs granted on January 29, 2014 and January 28, 2013 plus additional RPUs credited as a result of distribution equivalent rights granted in tandem with such deferred RPU award (the "Deferred RPUs")). Fair market value was calculated based on the closing price of our common units on the vesting date. Mr. Halbert S. Washburn did not elect to defer RPUs in 2015.
(2) Amount shown in Column (d) represents the loss in value from December 28, 2014 (the vesting date) through December 31, 2015 of 10,965 common units underlying the 2013 Deferred RPUs and 11,209 common units underlying the 2014 Deferred RPUs.
(3) Amount shown in Column (f) represents the year-end value of common units underlying RPUs that were vested as of December 31, 2014. The aggregate balance shown is based on the $0.67 closing price of our common units on December 31, 2015.

Potential Payments Upon Termination or Change in Control

The following tables present our reasonable estimate of the benefits payable to the named executive officers by us in the event of certain qualifying terminations of employment or upon a change in control or similar transaction, assuming that such termination or change in control or other transaction occurred on December 31, 2015. While we have made reasonable assumptions regarding the amounts payable, there can be no assurance that in the event of a termination, change in control or other transaction, the named executive officers would receive the amounts reflected below.

Termination Without Cause or for Good Reason

The following table presents our reasonable estimate of the benefits payable to our named executive officers in the event of a termination without cause or for good reason.

Name	Salary and Bonus	Employee Benefits	Value of Unit Award Acceleration(1)	Total Value
Halbert S. Washburn	$ 3,380,000 (2)	$ 38,670 (3)	$ 365,723	$ 3,784,393
Mark L. Pease	1,852,500 (4)	29,003 (5)	177,230	2,058,733
James G. Jackson	1,456,000 (4)	29,003 (5)	130,590	1,615,593
Gregory C. Brown................................	1,456,000 (4)	20,147 (5)	130,590	1,606,737
W. Jackson Washburn..........................	—	—	51,420	51,420

(1) Represents the aggregate estimated value of unvested RPUs and unvested CPUs held by Messrs. Halbert S. Washburn, Pease, Jackson, Brown and W. Jackson Washburn as of December 31, 2015 that would vest in connection with a termination without cause (other than in the case of death or disability) or for good reason, in either case in a manner that constitutes a "separation of service" within the meaning of Section 409A of the Code (each, a "Qualifying Termination"). The amount shown was calculated as the product of (a) the number of RPUs and the pro-rated number of CPUs held by the officer as of December 31, 2015, multiplied by (b) the closing price of our common units on December 31, 2015 ($0.67). Such estimated amount assumes that 1.00 CUE underlies each CPU. For a further description of the Long-Term Incentive Plan and the RPUs and CPUs granted thereunder, see "Compensation Discussion and Analysis — Components of Compensation — Long-Term Incentive Plan."

(2) Represents the aggregate estimated cash amount of severance to be paid under the Employment Agreement for Mr. Halbert S. Washburn in the event of a Qualifying Termination, equal to two times the sum of his base salary plus his "target bonus" (as defined in the respective Employment Agreement) as in effect immediately prior to the date of determination, and his pro-rata bonus (which, for purposes of the amount shown in the "Salary and Bonus" column, would equal the full amount of his "target bonus" for 2015). For a further description of the Employment Agreements, see "Compensation Discussion and Analysis — Components of Compensation — Employment Agreements."

(3) Represents the aggregate estimated cash amount to be paid under Mr. Halbert S. Washburn's Employment Agreement in the event of a Qualifying Termination for continued medical, prescription and dental benefits for the executive officer and his eligible dependents for a period of twenty-four months after termination of employment. For a further description of the Employment Agreements, see "Compensation Discussion and Analysis — Components of Compensation — Employment Agreements."

(4) Represents the aggregate estimated cash amount of severance to be paid under each of Messrs. Pease, Jackson and Brown's Employment Agreements in the event of a Qualifying Termination, equal to the sum of one and one-half times the sum of his annual base salary, plus his "target bonus" (as defined in the respective Employment Agreement) as in effect immediately prior to the date of determination, and his pro-rata bonus (which, for purposes of the amount shown in the "Salary and Bonus" column, would equal the full amount of his "target bonus" for 2015). For a further description of the Employment Agreements, see "Compensation Discussion and Analysis — Components of Compensation — Employment Agreements."

(5) Represents the aggregate estimated cash amount to be paid under each of Messrs. Pease, Jackson and Brown's Employment Agreements in the event of a Qualifying Termination for continued medical, prescription and dental benefits for the named executive officer and his eligible dependents for a period of eighteen months after termination of employment. For a further description of the Employment Agreements, see "Compensation Discussion and Analysis — Components of Compensation — Employment Agreements."

Termination Due to Death or Disability

The following table presents our reasonable estimate of the benefits payable to our named executive officers (or their estates) in the event of a termination due to death or disability.

Name	Salary and Bonus	Employee Benefits	Value of Unit Award Acceleration(1)	Total Value
Halbert S. Washburn	$ 676,000 (2)	$ 38,670 (3)	$ 365,723	$ 1,080,393
Mark L. Pease	444,600 (2)	29,003 (3)	177,230	650,833
James G. Jackson	332,800 (2)	29,003 (3)	130,590	492,393
Gregory C. Brown	332,800 (2)	20,147 (3)	130,590	483,537
W. Jackson Washburn	—	—	51,420	51,420

(1) Represents the aggregate estimated value of unvested RPUs held by each named executive officer and unvested CPUs held by Messrs. Halbert S. Washburn, Pease, Jackson, Brown and Mr. W. Jackson Washburn as of December 31, 2015 that would vest in connection with a termination due to death or disability. The amount shown was calculated as the product of (a) the number of RPUs and the pro-rated number of CPUs, held by the officer as of December 31, 2015, multiplied by (b) the closing price of our common units on December 31, 2015 ($0.67). Such estimated amount assumes that 1.00 CUE underlies each CPU. For a further description of the Long-Term Incentive Plan and the RPUs and CPUs granted thereunder, see "Compensation Discussion and Analysis — Components of Compensation — Long-Term Incentive Plan."

(2) Represents the aggregate estimated amount to be paid to the named executive officer under his Employment Agreement in connection with a termination due to death or disability, equal to the amount of the pro-rata bonus (which, for purposes of the amount shown in the "Salary and Bonus" column, would equal the full amount of his "target bonus" for 2015). For a further description of the Employment Agreements, see "Compensation Discussion and Analysis — Components of Compensation — Employment Agreements."

(3) Represents the aggregate estimated cash amount to be paid to the executive officer under his Employment Agreement in connection with a termination due to death or disability for continued medical, prescription and dental benefits for the executive officer and his eligible dependents for a period of twenty-four months after termination of employment for Mr. Halbert S. Washburn and a period of eighteen months for Messrs. Pease,

Jackson and Brown. For a further description of the Employment Agreements, see “Compensation Discussion and Analysis — Components of Compensation — Employment Agreements.”

Change in Control

The following table presents our reasonable estimate of the amounts payable to our named executive officers in the event of a change in control and/or a qualifying termination of employment in connection with a change in control, as applicable.

Name	Salary and Bonus	Employee Benefits	Value of Unit Award Acceleration(1)	Total Value
Halbert S. Washburn	$ 4,732,000 (2)	$ 38,670 (3)	$ 304,962	$ 5,075,632
Mark L. Pease	2,791,000 (4)	29,003 (5)	147,623	2,967,626
James G. Jackson	2,204,800 (4)	29,003 (5)	108,775	2,342,578
Gregory C. Brown	2,204,800 (4)	20,147 (5)	108,775	2,333,722
W. Jackson Washburn	—	—	42,830	42,830

(1) Represents the aggregate estimated value of unvested RPUs held by each named executive officer as of December 31, 2015 that would vest in connection with a “change in control.” The amount shown was calculated as the product of (a) the number of RPUs held by the officer as of December 31, 2015 multiplied by (b) the closing price of our common units on December 31, 2015 ($0.67). Pursuant to the terms of the CPU award agreements, unvested CPUs do not accelerate upon the occurrence of a change in control so no amount is included in the table with respect to these awards. For a further description of the Long-Term Incentive Plan and the RPUs and CPUs granted thereunder, see “Compensation Discussion and Analysis — Components of Compensation — Long-Term Incentive Plan.”

(2) Represents the aggregate estimated cash amount of severance to be paid under the Employment Agreements for Mr. Halbert S. Washburn in the event of a Qualifying Termination during the period beginning 60 days prior to and ending two years immediately following a “change in control” (as defined in the Employment Agreements), equal to three times the sum of his base salary plus his “target bonus” as in effect immediately prior to the date of determination, and his pro-rata bonus (which, for purposes of the amount shown in the “Salary and Bonus” column, would equal the full amount of his “target bonus” for 2015). For a further description of the Employment Agreements, see “Compensation Discussion and Analysis — Components of Compensation — Employment Agreements.”

(3) Represents the aggregate estimated cash amount to be paid under Mr. Halbert S. Washburn’s Employment Agreement in the event of a Qualifying Termination in connection with a “change in control” for continued medical, prescription and dental benefits for the executive officer and his eligible dependents for a period of twenty-four months after termination of employment. For a further description of the Employment Agreements, see “Compensation Discussion and Analysis — Components of Compensation — Employment Agreements.”

(4) Represents the aggregate estimated cash amount of severance to be paid under each of Messrs. Pease, Jackson and Brown’s Employment Agreements in the event of a Qualifying Termination during the period beginning 60 days prior to and ending two years immediately following a “change in control” (as defined in the Employment Agreements), equal to the sum of two and one-half times the sum of his annual base salary, plus his “target bonus” as in effect immediately prior to the date of determination, and his pro-rata bonus (which, for purposes of the amount shown in the “Salary and Bonus” column, would equal the full amount of his “target bonus” for 2015). For a further description of the Employment Agreements, see “Compensation Discussion and Analysis — Components of Compensation — Employment Agreements.”

(5) Represents the aggregate estimated cash amount to be paid under each of Messrs. Pease, Jackson and Brown’s Employment Agreements in the event of a Qualifying Termination in connection with a “change in control” for continued medical, prescription and dental benefits for the named executive officer and his eligible dependents for a period of eighteen months after termination of employment. For a further description of the Employment Agreements, see “Compensation Discussion and Analysis — Components of Compensation — Employment Agreements.”

Director Compensation

Officers of our General Partner or its affiliates who also serve as directors do not receive additional compensation for their service as a director of our General Partner. For 2015, each director who is not an officer of our General Partner or its affiliates received:

- a $40,000 cash annual retainer, except for the independent Chairman of the Board who received $90,000 in cash as an annual retainer;
- $1,500 for each meeting of the Board attended in person;
- $1,000 for each committee meeting attended in person;
- $500 for each telephonic meeting of a committee or the Board attended;
- for members of the Compensation and Governance Committee, $7,500 in cash annually, except for the Committee chair who received $15,000 in cash annually;
- for members of the Audit Committee, $7,500 in cash annually, except for the Committee chair who received $20,000 in cash annually; and
- an annual grant of $175,000 of RPUs vesting in three equal, annual installments, which will be settled in common units.

In addition, each director who is not an officer is reimbursed for his out-of-pocket expenses in connection with attending meetings of the Board or committees. We indemnify each director for actions associated with being a director to the fullest extent permitted under Delaware law.

On January 28, 2016, based on guidance from Meridian, the Compensation and Governance Committee approved grants to our directors of unit-settled RPUs, vesting in two equal installments on July 1, 2018 and January 1, 2019, and cash-settled RPUs, the terms of which are substantially similar to the 2016 grants of cash-settled RPUs made to our named executive officers; grants to our directors, however, may be settled for less than $0.50 per RPU and vest in two equal installments on July 1, 2017 and January 1, 2018). See "Compensation Discussion and Analysis—Executive Summary—2016 Compensation Decisions."

On November 30, 2012, Breitburn Management, our General Partner and we entered into a retirement agreement with Mr. Breitenbach, which terminates and supersedes his pre-existing employment agreement described above. Pursuant to the retirement agreement, Mr. Breitenbach retired as President of our General Partner, effective December 31, 2012, but continues to be employed by Breitburn Management relating to his PCEH service. Mr. Breitenbach was appointed Vice Chairman of the Board of our General Partner effective December 31, 2012. Subject to his execution and non-revocation of a general release of claims, Mr. Breitenbach has received or is entitled to receive the following retirement benefits: (i) a lump sum cash retirement payment of $1,450,000, which was paid on December 31, 2012, (ii) an equity-based award with a value equal to $2.55 million granted on January 28, 2013, consisting of 69,558 RPUs and 69,558 CPUs, (iii) an office and secretarial support at our sole expense as long as he continues to serve as a member of the Board, and (iv) as long as he continues to serve as a member of the Board and for a period of 18 months following the date on which he ceases to be a director, continued medical, prescription and dental benefits on the same basis and at the same cost as if he had continued to be an officer of the Partnership.

On November 30, 2012, Mr. Breitenbach's 2011 and 2012 RPU award agreements were amended to provide that following December 31, 2012, the awards will vest based on his continued service as a director and will vest in full in the event of a termination of his service as a director without "cause" or in the event of his death, "disability" or a "change in control" (each as defined in the award agreement).

The following table shows the compensation information for each of the directors, who is not an officer, of our General Partner for 2015.

2015 Director Compensation

Name [1]	Fees Earned or Paid in Cash	Stock Awards ($)[2][3]	All Other Compensation ($)[4]	Total
John R. Butler, Jr.	114,210	175,000	7,408	296,619
Randall H. Breitenbach	50,000	175,000	92,553	317,553
David B. Kilpatrick	83,000	175,000	7,408	265,408
Gregory J. Moroney	77,993	175,000	7,408	260,401
Kurt A. Talbot	47,500	175,000	—	47,500
Charles S. Weiss	89,000	175,000	7,408	271,408
Donald D. Wolf	65,839	175,000	7,408	248,247

(1) Mr. Halbert S. Washburn is not included in this table, because he is an officer and receives no compensation in his capacity as a director. The compensation received by Mr. Halbert S. Washburn as the Chief Executive Officer is shown in the Summary Compensation Table above.

(2) In accordance with ASC 718, represents the grant date fair value of RPU awards granted to each director in 2015. RPUs vest in three equal annual installments, or vest in full earlier in the event of the death or "disability" of the grantee, or a "change in control" (as each such term is defined in the applicable award agreement). Unvested RPUs otherwise are forfeited in the event that the grantee ceases to remain in the service of our General Partner. Upon vesting, each RPU will be paid in the form of one common unit. A holder of a RPU is entitled to participate in the amount of distributions made by us with respect to each of our common units during the term of the award. For a further discussion of the Long-Term Incentive Plan, see "—Compensation Discussion and Analysis—Components of Compensation—Long-Term Incentive Plan." The grant date fair value of each RPU is based on the closing price of a common unit on the date of grant. For additional information on the valuation assumptions and methodology used to determine the amounts set forth above for 2015, refer to Note 18 to the Partnership's consolidated financial statements for the year ended December 31, 2015, included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2015.

(3) The aggregate number of RPUs outstanding for each non-officer director other than Mr. Breitenbach, and with respect to Mr. Breitenbach, the aggregate number of RPUs and CPUs outstanding at December 31, 2015 is set forth in the table below. The directors did not have any outstanding options or other awards at December 31, 2015.

Name	Aggregate Stock Awards Outstanding, Number of Units (#)
John R. Butler, Jr.	35,572
Randall H. Breitenbach	32,413
David B. Kilpatrick	35,572
Gregory J. Moroney	35,572
Kurt A. Talbot	—
Charles S. Weiss	35,572
Donald D. Wolf	26,677

(4) Represents distributions paid to directors during 2015 on unvested RPUs granted on January 28, 2013, January 29, 2014 and January 26, 2015. With respect to Mr. Breitenbach, includes $13,522 in distributions paid during 2015 on unvested RPUs, $17,760in company-paid premiums for continued health insurance coverage during 2015, $4,380 for parking for 2015 and $53,863 for office services provided during 2015.

COMPENSATION POLICIES AND PRACTICES AS THEY RELATE TO RISK MANAGEMENT

The Compensation and Governance Committee oversees risk management as it relates to our compensation plans, policies and practices in connection with structuring our executive compensation programs and reviewing our incentive compensation programs for other employees and has met with management to review whether our compensation programs may create incentives for our employees to take excessive or inappropriate risks which could have a material adverse effect on the Partnership. As part of its review and assessment in 2015, the Compensation and Governance Committee considered the following characteristics of our compensation programs, among others, that discourage excessive or unnecessary risk taking:

- Our compensation programs appropriately balance short-term cash incentives and long-term equity incentives.
- Under our STIP, we measure the Partnership's operating and financial goals and performance by tracking a number of performance measures, including oil and gas production, lease operating expenses, capital efficiency, general and administrative expense and safety goals.
- Qualitative factors beyond quantitative financial metrics are a key consideration in determining bonus awards and the Compensation and Governance Committee retains discretion in determining bonus amounts awarded under the STIP.
- Maximum bonus payouts are established under our STIP which sets a ceiling, at the Compensation and Governance Committee's discretion, for cash bonus payments to all of our employees.
- Our awards under the Long-Term Incentive Plan are also set according to award targets and the Compensation and Governance Committee's discretion in determining the size of the grants.
- We provide a balanced mix of equity awards for executive officers and other management using grants of unit and unit linked awards in the form of RPUs and CPUs.

Based on this assessment, we believe that our compensation policies and programs do not present any risk that is reasonably likely to have a material adverse effect on the Partnership.

EQUITY COMPENSATION PLAN INFORMATION

The following table provides information as of December 31, 2015 about the common units of the Partnership that may be issued upon the exercise of options, warrants and rights under all of the Partnership's existing equity compensation plans.

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 (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	—	—	—
Equity compensation plans not approved by security holders			
Long-Term Incentive Plan	2,359,458 (1)	N/A (2)	14,124,253 (3)
Total	2,359,458	N/A	14,124,253

(1) Represents the number of common units to be issued under the Long-Term Incentive Plan. At the time the Long-Term Incentive Plan was adopted for the Partnership, security holder approval was not then required for the plan under the rules of the NASDAQ Stock Market LLC.
(2) Awards under the Long-Term Incentive Plan vest without payment by recipients.
(3) The Long-Term Incentive Plan provides that the Board or a committee of the Board may award restricted units, performance units or other unit-based awards and unit awards.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our common units and Series B units as of March 4, 2016, held by (1) beneficial owners of 5% or more of our common units and Series B units; (2) directors of our General Partner; (3) each named executive officer listed in this proxy statement; and (4) all current directors and executive officers of our General Partner as a group.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, 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, 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 of March 4, 2016. 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. Except as indicated by footnote, 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 included, for purposes of the table below, the principal business address for each such person is c/o Breitburn Energy Partners LP, 707 Wilshire Boulevard, Suite 4600, Los Angeles, CA 90017.

Name of Beneficial Owner	Units Beneficially Owned	Percentage of Units Beneficially Owned
Halbert S. Washburn[(1)(2)]	1,238,815	[(3)]
Mark L. Pease	495,457	[(3)]
James G. Jackson	420,067	[(3)]
Gregory C. Brown	432,374	[(3)]
W. Jackson Washburn	111,566	[(3)]
Randall H. Breitenbach[(1)(2)]	1,183,999	[(3)]
John R. Butler, Jr.	118,605	[(3)]
David B. Kilpatrick	96,256	[(3)]
Gregory J. Moroney	54,852	[(3)]
Kurt A. Talbot	—	—
Charles S. Weiss	71,731	[(3)]
Donald D. Wolf	196,514	[(3)]
The Strand Energy Company[(1)]	690,751	[(3)]
EIG Redwood Equity Aggregator, LP	37,462,156	14.24%
All directors and executive officers as a group (15 persons)	3,889,965	1.48%

(1) Messrs. Halbert S. Washburn and Breitenbach collectively own 74% of the outstanding shares and hold 100% of the voting rights of The Strand Energy Company (formerly named BreitBurn Energy Corporation).
(2) Includes common units beneficially owned by The Strand Energy Company.
(3) Less than 1%.

HOUSEHOLDING NOTICE

We are sending only one copy of our proxy statement and 2015 Annual Report to unitholders who share the same last name and address, unless they have notified us that they want to continue receiving multiple copies. This practice, known as "householding," is designed to reduce duplicate mailings and save significant printing and postage costs.

If you received a householded mailing this year and you would like to have additional copies of our proxy statement and 2015 Annual Report mailed to you or you would like to opt out of this practice for future mailings, we will promptly deliver such additional copies to you or remove you from our householding list, as applicable, if you submit your request to our Investor Relations Department in writing at 707 Wilshire Boulevard, Suite 4600, Los Angeles, California 90017 or by telephone at (213) 225-5900. You may also contact us in the same manner if you received multiple copies of the Annual Meeting materials and would prefer to receive a single copy in the future.

PROPOSALS FOR THE NEXT ANNUAL MEETING

If our annual meeting of limited partners for the year ended December 31, 2016 is held within 30 days before or 70 days after April 28, 2017, in order to nominate a person for election to the Board, notice must be received in writing by our Investor Relations Department at our principal executive offices at 707 Wilshire Boulevard, Suite 4600, Los Angeles, California 90017, no later than the close of business on January 30, 2017 and no earlier than the close of business on December 29, 2016. If our 2017 meeting of limited partners is held more than 30 days before or 70 days after April 28, 2017, unitholder nominations to the Board must be received in writing by our Investor Relations Department at the address listed above not earlier than the close of business on the 120th day prior to such annual meeting and not later than the close of business on the later of the 90th day prior to such annual meeting or the 10th day following the day on which public announcement of the date of the meeting is first made by the Partnership or our General Partner. All such unitholder nominations must also be otherwise eligible for inclusion under the terms set forth in the Partnership Agreement. For additional information, please see the section entitled "Corporate Governance — Nomination of Director Candidates by Unitholders."

Limited partners who wish to have proposals considered for inclusion in the proxy statement and form of proxy for our 2017 meeting of limited partners pursuant to Rule 14a-8 under the Exchange Act must cause their proposals to be received in writing by our Corporate Secretary at the address listed above no later than November 7, 2016. Any proposal should be addressed to our Corporate Secretary and may be included in next year's proxy materials only if such proposal complies with all SEC rules and regulations.

2015 ANNUAL REPORT

A copy of our 2015 Annual Report, including the financial statements and the financial statement schedules, if any, but not including exhibits, will be furnished at no charge to each person to whom a proxy statement is delivered upon the written request of such person addressed to our Investor Relations Department at 707 Wilshire Boulevard, Suite 4600, Los Angeles, California, 90017.

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Directors**

*John R. Butler, Jr.**[(2)]
Chairman of the Board of Directors

Chairman of J.R. Butler and Company
Member of the Board of Directors of Texas Tri-Cities chapter of the National Association of Corporate Directors

Randall H. Breitenbach
Vice Chairman of the Board of Directors

Chief Executive Officer and Chairman of the Board of Directors of Pacific Coast Energy Holdings LLC
Trustee and Chairman of the Governance and Nominating Committee of Hotchkis and Wiley Funds

*David B. Kilpatrick**[(1) (2)]
Chairman of the Compensation and Governance Committee

President of Kilpatrick Energy Group
Member of the Board and Governance Committee of Cheniere Energy, Inc.
Member of the Board of Woodbine Holdings, LLC
Chairman of the Board of Directors of Applied Natural Gas Fuels, Inc.

*Gregory J. Moroney**[(1) (2)]

Managing Member and Owner of Energy Capital Advisors, LLC
Senior Financial Consultant for Ammonite Resources LLC
Member of the Board of Directors and Audit, Remuneration and Nominating Committee of Xcite Energy Limited, BVI

Kurt A. Talbot

Senior Advisor and Member of the Executive Committee of EIG Global Energy Partners
Previously member of the Board of Directors of Plains Offshore Operations Inc.

*Charles S. Weiss**[(1) (2)]
Chairman of the Audit Committee

Founder and Managing Partner, and Member of the Board of Directors of JOG Capital, Inc.
Member of the Board of Directors of the National Forest Foundation

*Donald D. Wolf**[(1)]

Director of MarkWest Energy Partners, L.P., Enduring Resources, LLC, Laredo Petroleum, LLC, and Aspect Energy, LLC

Management**
Halbert S. Washburn
Chief Executive Officer and Director

Mark L. Pease
President and Chief Operating Officer

James G. Jackson
Executive Vice President and Chief Financial Officer

Gregory C. Brown
Executive Vice President, General Counsel and Chief Administrative Officer

W. Jackson Washburn
Senior Vice President

Thomas E. Thurmond
Senior Vice President

Bruce D. McFarland
Vice President and Treasurer

Lawrence C. Smith
Vice President, Controller and Chief Accounting Officer

*Independent Director
**Of our General Partner Breitburn GP LLC

(1) Member of the Audit Committee
(2) Member of the Compensation & Governance Committee

Investor Relations

Breitburn Energy Partners LP
707 Wilshire Boulevard,
Suite 4600
Los Angeles, California 90017
(213) 225-0390
www.breitburn.com

Transfer Agent and Registrar

American Stock Transfer and Trust Company
6201 15th Avenue
Brooklyn, New York 11219
(800) 937-5449

Independent Registered Public Accounting Firm
PricewaterhouseCoopers LLP
Los Angeles, California

Legal Counsel

Vinson & Elkins LLP
New York, New York and Houston, Texas

Latham & Watkins LLP
Los Angeles, California

Unitholder Information

Our common units and 8.25% Series A Cumulative Redeemable Perpetual Preferred units are publicly traded on the NASDAQ under the symbol “BBEP” and “BBEPP”, respectively