BREITBURN ENERGY PARTNERS LP

FORM 10-Q
(Quarterly Report)

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Address	707 WILSHIRE BOULEVARD 46TH FLOOR LOS ANGELES, CA 90017
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

☒ Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended June 30, 2017

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 Number)*
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

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 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," "smaller reporting company," and "emerging growth 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 ☐
Emerging growth company ☐	

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

As of August 8, 2017 , the registrant had 213,789,296 Common Units outstanding.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Forward-looking statements are included in this report and may be included in other public filings, press releases, our website and oral and written presentations by management. Statements other than historical facts are forward-looking and may be identified by words such as “believe,” “estimate,” “impact,” “intend,” “future,” “affect,” “expect,” “will,” “projected,” “plan,” “anticipate,” “should,” “could,” “would,” variations of such words and words of similar meaning. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this report.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are changes in crude oil, natural gas liquids (“NGL”) and natural gas prices, including further or sustained declines in the prices we receive for our production; risks and uncertainties associated with the restructuring process, including our inability to develop, confirm and consummate a plan under chapter 11 of the United States Bankruptcy Code or an alternative restructuring transaction; inability to maintain our relationships with suppliers, customers, other third parties or our employees as a result of the restructuring process; delays in planned or expected drilling; changes in costs and availability of drilling, completion and production equipment and related services and labor; the ability to obtain sufficient quantities of carbon dioxide (“CO_2”) necessary to carry out enhanced oil recovery projects; the discovery of previously unknown environmental issues; federal, state and local initiatives and efforts relating to the regulation of hydraulic fracturing; the competitiveness of alternate energy sources or product substitutes; technological developments; potential disruption or interruption of our net production due to accidents or severe weather; the level of success in exploitation, development and production activities; the timing of exploitation and development expenditures; inaccuracies of reserve estimates or assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; impacts to financial statements as a result of impairment write-downs; risks related to level of indebtedness; ability to continue to borrow under our debtor-in-possession credit agreement; ability to generate sufficient cash flows from operations to meet the internally funded portion of any capital expenditures budget; changes in our business strategy; ability to obtain external capital to finance exploitation and development operations and acquisitions; the potential need to sell certain assets, restructure our debt or raise additional capital; our future levels of indebtedness, liquidity, compliance with financial covenants and our ability to continue as a going concern; failure of properties to yield oil or natural gas in commercially viable quantities; ability to integrate successfully the businesses we acquire; uninsured or underinsured losses resulting from oil and natural gas operations; inability to access oil and natural gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing oil and natural gas operations; changes in governmental regulations, including the regulation of derivative instruments and the oil and natural gas industry; ability to replace oil and natural gas reserves; any loss of senior management or technical personnel; competition in the oil and natural gas industry; risks arising out of hedging transactions; the effects of changes in accounting rules under generally accepted accounting principles promulgated by rule-setting bodies; and the factors set forth under “Cautionary Statement Regarding Forward-Looking Information” and Part I—Item 1A “—Risk Factors” of our Annual Report on Form 10-K for the year ended December 31, 2016 (our “2016 Annual Report”), and under Part II—Item 1A of this report. Unpredictable or unknown factors not discussed herein also could have material adverse effects on forward-looking statements.

All forward-looking statements, expressed or implied, included in this report and attributable to us are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

We undertake no obligation to update the forward-looking statements in this report to reflect future events or circumstances.

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

Breitburn Energy Partners LP and Subsidiaries
(Debtor-in-Possession)
Consolidated Balance Sheets
(Unaudited)

Thousands of dollars	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash	$ 10,424	$ 71,124
Accounts and other receivables, net	536,548	549,544
Related party receivables (note 4)	587	860
Inventory	1,637	998
Prepaid expenses and other current assets	9,282	8,230
Total current assets	558,478	630,756
Equity investments	5,550	7,160
Property, plant and equipment		
Oil and natural gas properties	7,959,537	7,907,136
Other property, plant and equipment	189,425	192,724
	8,148,962	8,099,860
Accumulated depletion, depreciation, and impairment (note 5)	(4,831,025)	(4,686,214)
Net property, plant and equipment	3,317,937	3,413,646
Other long-term assets		
Other long-term assets (note 6)	65,869	63,846
Total assets	$ 3,947,834	$ 4,115,408
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 52,731	$ 47,838
Current portion of long-term debt (note 7)	1,198,259	1,198,259
Current portion of asset retirement obligation	5,031	5,905
Revenue and royalties payable	35,606	37,271
Wages and salaries payable	11,489	11,057
Accrued interest payable	610	21,064
Production and property taxes payable	15,630	15,340
Other current liabilities	13,979	17,466
Total current liabilities	1,333,335	1,354,200
Liabilities subject to compromise (note 2)	1,878,781	1,879,176
Long-term debt (note 7)	3,109	3,094
Deferred income taxes	2,591	2,771
Asset retirement obligation (note 9)	260,199	252,589
Other long-term liabilities	17,142	17,551
Total liabilities	3,495,157	3,509,381
Commitments and contingencies (note 10)		
Equity		
Series A preferred units, 8.0 million units issued and outstanding at each of June 30, 2017 and December 31, 2016 (note 11)	193,215	193,215
Series B preferred units, 49.6 million units issued and outstanding at each of June 30, 2017 and December 31, 2016 (note 11)	359,611	359,611
Common unitholders' (deficit) equity, 213.8 million units issued and outstanding at each of June 30, 2017 and December 31, 2016 (note 11)	(109,115)	45,158
Accumulated other comprehensive income (note 12)	1,453	1,032
Total partners' equity	445,164	599,016
Noncontrolling interest	7,513	7,011
Total equity	452,677	606,027

Total liabilities and equity	$	3,947,834	$	4,115,408

See accompanying notes to consolidated financial statements.

Breitburn Energy Partners LP and Subsidiaries
(Debtor-in-possession)
Consolidated Statements of Operations
(Unaudited)

Thousands of dollars, except per unit amounts	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Revenues and other income items				
Oil, natural gas and natural gas liquid sales	$ 136,703	$ 127,282	$ 283,979	$ 232,732
Loss on commodity derivative instruments, net (note 3)	—	(92,210)	—	(54,287)
Other revenue, net	4,406	4,362	8,860	8,955
Total revenues and other income items	141,109	39,434	292,839	187,400
Operating costs and expenses				
Operating costs	93,724	83,795	193,512	178,769
Depletion, depreciation and amortization	63,197	81,960	136,561	165,683
Impairment of oil and natural gas properties (note 5)	321	—	17,211	2,793
General and administrative expenses	17,197	16,270	34,769	37,684
Restructuring costs (note 14)	—	2,439	—	5,248
Loss (gain) on sale of assets	8	(2)	7	(12,262)
Total operating costs and expenses	174,447	184,462	382,060	377,915
Operating loss	(33,338)	(145,028)	(89,221)	(190,515)
Interest expense, net of capitalized interest	23,024	49,917	45,105	105,906
(Gain) loss on interest rate swaps (note 3)	—	(533)	—	1,810
Other (income) expense, net	(204)	(130)	(341)	152
Reorganization items, net (note 2)	10,167	66,897	20,507	66,897
Loss before taxes	(66,325)	(261,179)	(154,492)	(365,280)
Income tax (benefit) expense	(533)	371	(431)	276
Net loss	(65,792)	(261,550)	(154,061)	(365,556)
Less: Net income (loss) attributable to noncontrolling interest	172	(235)	213	(455)
Net loss attributable to the partnership	(65,964)	(261,315)	(154,274)	(365,101)
Less: Distributions to Series A preferred unitholders	—	2,017	—	6,142
Less: Non-cash distributions to Series B preferred unitholders	—	3,737	—	11,123
Net loss used to calculate basic and diluted net loss per unit	$ (65,964)	$ (267,069)	$ (154,274)	$ (382,366)
Basic net loss per common unit (note 12)	$ (0.31)	$ (1.25)	$ (0.72)	$ (1.79)
Diluted net loss per common unit (note 12)	$ (0.31)	$ (1.25)	$ (0.72)	$ (1.79)
Weighted average number of units used to calculate basic and diluted net loss per unit (in thousands):				
Basic	213,789	213,779	213,789	213,720
Diluted	213,789	213,779	213,789	213,720

See accompanying notes to consolidated financial statements.

Breitburn Energy Partners LP and Subsidiaries
(Debtor-in-possession)
Consolidated Statements of Comprehensive Loss
(Unaudited)

Thousands of dollars, except per unit amounts	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Net loss	$ (65,792)	$ (261,550)	$ (154,061)	$ (365,556)
Other comprehensive (loss) income, net of tax:				
Change in fair value of available-for-sale securities (a)	(158)	263	751	733
Pension and post-retirement benefits actuarial income (loss) (b)	1	(781)	(41)	(781)
Total other comprehensive (loss) income	(157) —	(518)	710	(48)
Total comprehensive income loss	(65,949) —	(262,068)	(153,351)	(365,604)
Less: Comprehensive loss attributable to noncontrolling interest	108	(447)	503	(475)
Comprehensive loss attributable to the partnership	$ (66,057)	$ (261,621)	$ (153,854)	$ (365,129)

(a) Net of income tax (benefit) expense of $(0.6) million and $0.1 million for the three months ended June 30, 2017 and 2016 , respectively. Net of income tax (benefit) expense of $(0.4) million and $0.4 million for the six months ended June 30, 2017 and 2016 , respectively.
(b) Net of income tax expense (benefit) of less than $0.1 million and $(0.4) million for the three months ended June 30, 2017 and 2016 , respectively. Net of income tax expense (benefit) of less than $0.1 million and $(0.4) million for the six months ended June 30, 2017 and 2016 , respectively.

See accompanying notes to consolidated financial statements.

Breitburn Energy Partners LP and Subsidiaries
(Debtor-in-possession)
Consolidated Statements of Cash Flows
(Unaudited)

Thousands of dollars	Six Months Ended June 30, 2017	2016
Cash flows from operating activities		
Net loss	$ (154,061)	$ (365,556)
Adjustments to reconcile to cash flows from operating activities:		
Depletion, depreciation and amortization	136,561	165,683
Impairment of oil and natural gas properties	17,211	2,793
Unit-based compensation expense	—	10,075
Loss on derivative instruments	—	56,097
Derivative instrument settlement receipts	—	172,199
Income from equity affiliates, net	1,610	(223)
Deferred income taxes	(180)	(308)
Gain on sale of assets	7	(12,262)
Non-cash reorganization items	292	48,829
Amortization and write-off of debt issuance costs	—	24,943
Other	(3,741)	1,489
Changes in net assets and liabilities		
Accounts receivable and other assets	10,374	4,156
Inventory	(639)	(435)
Net change in related party receivables and payables	273	873
Accounts payable and other liabilities	(20,808)	52,641
Net cash (used in) provided by operating activities	(13,101)	160,994
Cash flows from investing activities		
Property acquisitions, net of cash acquired	(1,962)	(5,983)
Capital expenditures	(44,327)	(46,287)
Proceeds from sale of assets	350	11,797
Proceeds from sale of available-for-sale securities	89	6,319
Purchases of available-for-sale securities	(92)	(6,893)
Net cash used in investing activities	(45,942)	(41,047)
Cash flows from financing activities		
Distributions to preferred unitholders	—	(5,501)
Proceeds from issuance of long-term debt, net	—	37,329
Repayments of long-term debt	—	(69,000)
Proceeds from debtor-in-possession financing	3,000	—
Repayments of debtor-in-possession financing	(3,000)	—
Principal payments on capital lease obligations	—	(39)
Change in bank overdraft	8	(65)
Debtor-in-possession debt issuance costs	(1,665)	(2,672)
Long-term debt issuance costs	—	(3)
Net cash used in financing activities	(1,657)	(39,951)
(Decrease) increase in cash	(60,700)	79,996
Cash beginning of period	71,124	10,464
Cash end of period	$ 10,424	$ 90,460

See accompanying notes to consolidated financial statements.

Condensed Notes to Consolidated Financial Statements
(Unaudited)

1. Organization and Basis of Presentation

The accompanying unaudited condensed consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2016 (“ 2016 Annual Report”). The financial statements have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. The information reported herein reflects all normal recurring adjustments that are, in the opinion of management, considered necessary for a fair statement of our financial position at June 30, 2017 , our operating results for the three months and six months ended June 30, 2017 and 2016 and our cash flows for the six months ended June 30, 2017 and 2016 have been included. Operating results for the three months and six months ended June 30, 2017 are not necessarily indicative of the results that may be expected for the year ended December 31, 2017 . The consolidated balance sheet at December 31, 2016 has been derived from the audited consolidated financial statements at that date but does not include all of the information and notes required by GAAP for complete financial statements. For further information, refer to the consolidated financial statements and notes thereto included in our 2016 Annual Report.

We follow the successful efforts method of accounting for oil and natural gas activities. Depletion, depreciation and amortization (“DD&A”) of proved oil and natural gas properties is computed using the units-of-production method, net of any estimated residual salvage values.

Chapter 11 Cases

On May 15, 2016 (the “Chapter 11 Filing Date”), we and certain of our subsidiaries filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of New York. See Note 2 for a discussion of the Chapter 11 Cases (as defined in Note 2).

The accompanying consolidated financial statements have been prepared assuming that we will continue as a going concern, which contemplates continuity of operations, the realization of assets and the satisfaction of liabilities and commitments in the normal course of business.

See Note 2 for a discussion of our liquidity and ability to continue as a going concern.

Accounting Standards

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standard Update (“ASU”) 2014-09 (Topic 606), *Revenue from Contracts with Customers* . Topic 606 supersedes the revenue recognition requirements in Accounting Standards Codification Topic 605, *Revenue Recognition* , and requires 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. Topic 606 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. Topic 606 becomes effective January 1, 2018 and permits the use of either the full retrospective or cumulative effect transition method upon adoption. We intend to use the modified retrospective transition method applied to the contracts not yet complete as of the date of initial adoption, and to recognize the cumulative effect adjustment to our opening retained earnings balance in the period of adoption. We are continuing to evaluate the effect that adoption of Topic 606 will have on our consolidated financial statements and related disclosures, specifically principal versus agent considerations and gas imbalance arrangements. We are also continuing to monitor developments regarding Topic 606 that are unique to the oil and natural gas industry.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities.* The amendments provide guidance on financial instruments specifically related to (i) the classification and measurement of investments in equity securities, (ii) the presentation of certain fair value changes for financial liabilities measured at fair value and (iii) certain disclosure requirements associated with the fair value of financial instruments. ASU 2016-01 is effective for annual and interim periods beginning after December 15, 2017, with early adoption permitted. A cumulative-effect adjustment to beginning retained earnings is required as of the beginning of the fiscal year in which this ASU is adopted. The adoption of this ASU will not have a significant impact on our consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* , which requires recognizing a right-of-use lease asset and a lease liability on the balance sheet. Lessees are permitted to make an accounting policy to elect not to recognize lease assets and lease liabilities for leases with a term of 12 months or less, and to recognize lease expense on a straight-line basis over the lease term. These new requirements become effective for annual and interim periods beginning after December 15, 2018, with early adoption permitted. We are assessing the impact that ASU 2016-02 will have on our consolidated financial statements. This ASU will primarily be applicable to existing office leases and equipment leasing arrangements with terms in excess of 12 months.

In March 2016, the FASB issued ASU 2016-09, *Compensation — Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* . The amendments simplify certain areas of accounting for share-based payment transactions, including classification of awards as either equity or liability, classification on the statement of cash flows, and election of accounting policy to estimate forfeitures or recognize forfeitures when they occur. The amendments are effective for annual and interim periods beginning after December 15, 2016. Early adoption is permitted, however, adoption of all of the amendments are required in the same period of adoption. As of December 31, 2016, all unvested equity awards were canceled, and, therefore, the adoption of this ASU had no impact on the financial statements presented in this report.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments—Credit Losses: Measurement of Credit Losses on Financial Instruments.* The objective of this update is to provide more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. The amendments in this update replace the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. ASU 2016-13 is effective for annual and interim periods beginning after December 15, 2019, with early adoption permitted. We are assessing the impact that ASU 2016-13 will have on our consolidated financial statements.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments.* This update was issued to reduce diversity in practice of how certain cash receipts and cash payments are presented and classified in the statement of cash flows, including debt prepayment or debt extinguishment costs, proceeds from the settlement of insurance claims and distributions received from equity method investees. ASU 2016-15 is effective for annual and interim periods beginning after December 15, 2017, with early adoption permitted. We are assessing the impact that ASU 2016-15 will have on our consolidated financial statements.

In November 2016, the FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* . To reduce diversity in practice, this update requires that the statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. ASU 2016-18 is effective for annual and interim periods beginning after December 15, 2017, with early adoption permitted. The adoption of this ASU will impact the reconciliation of beginning and ending cash flow on our statements of cash flows, as it requires the inclusion of restricted cash.

2. Chapter 11 Cases and Liquidity

Chapter 11 Cases

On May 15, 2016, we and 21 of our subsidiaries (collectively, the “Debtors”) filed voluntary petitions for relief (collectively, the “Chapter 11 Petitions” and the cases commenced thereby, the “Chapter 11 Cases”) under chapter 11 of the United States Bankruptcy Code (the “Bankruptcy Code”) in the United States Bankruptcy Court for the Southern District of New York (the “Bankruptcy Court”). The Chapter 11 Cases are being jointly administered under the caption “In re Breitburn Energy Partners LP, et al.,” Case No. 16-11390 . No trustee has been appointed and we continue to manage ourselves and our affiliates and operate our businesses as “debtors in possession” subject to the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court. To assure ordinary course operations, we received approval from the Bankruptcy Court on a variety of “first day” motions, including motions that authorize us to maintain our existing cash management system, to secure debtor-in-possession financing and other customary relief. In connection with the Chapter 11 Cases, Breitburn Operating LP (“BOLP”) entered into the Debtor-in-Possession Credit Agreement, dated as of May 19, 2016, among itself, as borrower, Breitburn Energy Partners LP (the

“Partnership”), as parent guarantor, the financial institutions from time to time party thereto and Wells Fargo Bank, National Association, as administrative agent, swing line lender and issuing lender (as amended, the “DIP Credit Agreement”). The other Debtors have guaranteed all obligations under the DIP Credit Agreement. See Note 8 for a discussion of the DIP Credit Agreement.

On December 13, 2016, the Bankruptcy Court entered an order approving the First Amendment to the DIP Credit Agreement, effective as of December 15, 2016, by and among the DIP Borrower, the lenders party thereto (the “DIP Lenders”) and the Administrative Agent (the “First Amendment”). The First Amendment, among other things, (i) extended the DIP Credit Agreement’s scheduled maturity date to June 30, 2017, (ii) increased certain pricing, (iii) increased the committed amount available under the DIP Credit Agreement from $75 million to $150 million, (iv) increased the letter of credit sublimit from $50 million to $100 million and (v) provided for the payment of certain fees to the Administrative Agent and the DIP Lenders . On May 10, 2017, the Bankruptcy Court entered an order approving the Third Amendment to the DIP Credit Agreement, effective as of May 11, 2017, by and among the DIP Borrower, the Partnership, the DIP Lenders and the Administrative Agent (the “Third Amendment”). The Third Amendment, among other things, extended the DIP Credit Agreement’s scheduled maturity date to September 30, 2017 and provided for the payment of certain fees to the Administrative Agent and the DIP Lenders.

ASC 852-10, *Reorganizations* , applies to entities that have filed a petition for relief under chapter 11 of the Bankruptcy Code. In accordance with ASC 852-10, transactions and events directly associated with the reorganization are required to be distinguished from the ongoing operations of the business. In addition, the guidance requires changes in the accounting and presentation of liabilities, as well as expenses and income directly associated with the Chapter 11 Cases.

The commencement of the Chapter 11 Cases resulted in the acceleration of the Debtors’ obligations under the Third Amended and Restated Credit Agreement, dated as of November 19, 2014, by and among BOLP, as borrower, the Partnership, as parent guarantor, the lenders from time to time party thereto and Wells Fargo Bank, National Association, as administrative agent, swing line lender and issuing lender (as amended, the “RBL Credit Agreement”), and the indentures governing our 9.25% Senior Secured Second Lien Notes due 2020 (“Senior Secured Notes”), our 8.625% Senior Notes due 2020 (“2020 Senior Notes”) and our 7.875% Senior Notes due 2022 (“2022 Senior Notes,” and together with the 2020 Senior Notes, the “Senior Unsecured Notes”). Any efforts to enforce such obligations are automatically stayed as a result of the filing of the Chapter 11 Petitions and the holders’ rights of enforcement in respect of these obligations are subject to the applicable provisions of the Bankruptcy Code. See Note 8 for a discussion of our RBL Credit Agreement (which has been reclassified from long-term debt to current portion of long-term debt on our consolidated balance sheets) and our Senior Secured Notes and Senior Unsecured Notes (which have been reclassified from long-term debt to liabilities subject to compromise on our consolidated balance sheets).

We are making adequate protection payments with respect to the RBL Credit Agreement, reflected in interest expense, net of capitalized interest on the consolidated statements of operations, consisting of the payment of interest (at the default rate) and the payment of all reasonable fees and expenses of professionals retained by our lenders, as provided for in the RBL Credit Agreement. We are also making adequate protection payments with respect to the Senior Secured Notes in the form of the payment of all reasonable fees and expenses of professionals retained by the holders of the Senior Secured Notes.

The commencement of the Chapter 11 Cases also resulted in a termination right by our counterparties on our commodity and interest rate derivative instruments. See Note 3 for a discussion of the derivative instruments, which were terminated, and resulted in $460.0 million in estimated hedge settlements receivable and $4.1 million in estimated hedge settlements payable, reflected in accounts and other receivables, net and other current liabilities, respectively, on the consolidated balance sheet at each of June 30, 2017 and December 31, 2016 , respectively.

Effect of Filing on Creditors and Unitholders

On April 14, 2016, we elected to suspend the declaration of any further distributions on our Series A Cumulative Redeemable Perpetual Preferred Units (“Series A Preferred Units”) and Series B Perpetual Convertible Preferred Units (“Series B Preferred Units”). In addition, we elected to defer a $33.5 million interest payment due with respect to our 2022 Senior Notes and a $13.2 million interest payment due with respect to our 2020 Senior Notes, with each such interest payment due on April 15, 2016 and subject to a 30-day grace period. As a consequence of the commencement of the Chapter 11 Cases, such interest payments have not been made, and are classified as liabilities subject to compromise on the consolidated balance sheet at June 30, 2017 and December 31, 2016 .

On May 15, 2016, we filed the Chapter 11 Petitions. Under the priority scheme established by the Bankruptcy Code, unless creditors agree otherwise, pre-petition liabilities and post-petition liabilities must be satisfied in full before the holders of our Series A Preferred Units, Series B Preferred Units and common units representing limited partner interests in us ("Common Units") are entitled to receive any distribution or retain any property under a plan of reorganization. The ultimate recovery to creditors and/or unitholders, if any, will not be determined until confirmation and implementation of a plan of reorganization. No assurance can be given as to what distributions, if any, will be made to each of these constituencies or the nature thereof. As discussed below, if certain requirements of the Bankruptcy Code are met, a plan of reorganization can be confirmed notwithstanding its rejection or deemed rejection by the holders of our Series A Preferred Units, Series B Preferred Units and Common Units and notwithstanding the fact that such holders do not receive or retain any property on account of their equity interests under the plan. Because of such possibilities, the value of our securities, including our Series A Preferred Units, Series B Preferred Units and Common Units, is highly speculative. There can be no assurance that the holders of our Series A Preferred Units, Series B Preferred Units and Common Units will retain any value under a plan of reorganization. We believe it is highly likely that our Series A Preferred Units, Series B Preferred Units and Common Units will be canceled in our Chapter 11 Cases and that the holders thereof will not receive any distribution on account of their holdings.

Executory Contracts . Subject to certain exceptions, under the Bankruptcy Code, the Debtors may assume, assign, or reject certain executory contracts and unexpired leases, subject to the approval of the Bankruptcy Court. The rejection of an executory contract or unexpired lease is generally treated as a pre-petition breach of such executory contract or unexpired lease and, subject to certain exceptions, relieves the Debtors of performing their future obligations under such executory contract or unexpired lease, but may give rise to a pre-petition general unsecured claim for damages caused by such deemed breach. The assumption of an executory contract or unexpired lease generally requires the Debtors to cure existing monetary defaults under such executory contract or unexpired lease and provide adequate assurance of future performance. By order of the Bankruptcy Court dated December 12, 2016, the Debtors assumed all of their executory contracts and unexpired leases related to their oil and gas operations to the extent such contracts and leases constituted commercial property leases under the purview of the Bankruptcy Code.

Process for Plan of Reorganization . In order to successfully emerge from Chapter 11, the Debtors will need to obtain confirmation by the Bankruptcy Court of a plan of reorganization that satisfies the requirements of the Bankruptcy Code. A plan of reorganization generally provides for how pre-petition obligations and equity interests will be treated in satisfaction and discharge thereof, and provides for the means by which the plan of reorganization will be implemented.

Fresh Start Accounting . We may be required to adopt fresh start accounting upon emergence from Chapter 11. Adopting fresh start accounting would result in the allocation of the reorganization value to individual assets based on their estimated fair values. The enterprise value of the equity of the emerging company is based on several assumptions and inputs contemplated in the future projections of the plan of reorganization and are subject to significant uncertainties. We currently cannot estimate the potential financial effect of fresh start accounting on our consolidated financial statements upon the emergence from Chapter 11, although we would expect to recognize material adjustments upon implementation of fresh-start accounting guidance upon emergence pursuant to a plan of reorganization. The assumptions for which there is a reasonable possibility of material impact affecting the reorganization value include, but are not limited to, management's assumptions and capital expenditure plans related to the estimation of our oil and gas reserves.

Debtors Condensed Combined Financial Statements. Two of our subsidiaries, Breitburn Collingwood Utica LLC and East Texas Salt Water Disposal Company ("ETSWDC"), are non-debtors ("Non-Debtors"). Accordingly, these entities will be accounted for under GAAP for entities not in bankruptcy and outside the scope of ASC 852. The Non-Debtors are minor subsidiaries, and, as such, we have not presented Debtors Condensed Combined Financial Statements.

Costs of Reorganization

The Debtors have incurred and will continue to incur significant costs associated with the Chapter 11 Cases. The amount of these costs, which are being expensed as incurred, are expected to significantly affect our results. The following table summarizes the components included in reorganization items, net on our consolidated statements of operations for the three months ended June 30, 2017 :

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands of dollars	**2017**	**2016**	**2017**	**2016**
Debt discounts/premiums and issuance costs	$ —	$ 48,829	$ —	$ 48,829
Advisory and professional fees	9,226	13,963	19,383	13,963
DIP Credit Agreement debt issuance costs	465	4,172	465	4,172
Other	476	(67)	659	(67)
Reorganization items, net	$ 10,167	$ 66,897	$ 20,507	$ 66,897

We use this category to reflect the net expenses and gains and losses that are the result of the reorganization and restructuring of the business. Advisory and professional fees included in the table above represent professional fees for post-petition expenses. As of June 30, 2017 , we had $12.7 million of accrued reorganization costs not yet paid included in accounts payable on the consolidated balance sheet, consisting primarily of advisory and professional fees.

Liabilities Subject to Compromise

Liabilities subject to compromise in our consolidated financial statements include pre-petition liabilities that may be affected by the plan of reorganization at the amounts expected to be allowed, even if they may be settled for lesser amounts. If there is uncertainty about whether a secured claim is under-secured, or will be impaired under the plan of reorganization, the entire amount of the claim is included in liabilities subject to compromise. Differences between liabilities we have estimated and the claims to be filed will be investigated and resolved in connection with the claims resolution process in the Chapter 11 Cases. We will continue to evaluate these liabilities throughout the Chapter 11 Cases and adjust amounts as necessary. Such adjustments may be material.

Our consolidated financial statements include amounts classified as liabilities subject to compromise that we believe the Bankruptcy Court will allow as claim amounts resulting from the Debtors' rejection of various executory contracts and unexpired leases and defaults under the debt agreements. Additional amounts may be included in liabilities subject to compromise in future periods if other executory contracts and unexpired leases are rejected. Conversely, the Debtors expect that the assumption of certain executory contracts and unexpired leases may convert certain liabilities currently shown in our financial statements as subject to compromise to post-petition liabilities. Due to the uncertain nature of many of the potential claims, the magnitude of such claims is not reasonably estimable at this time. Such claims may be material. The RBL Credit Agreement was fully collateralized at the Chapter 11 Filing Date and, as a result, has been classified as current portion of long-term debt on our consolidated balance sheets, rather than being classified as liabilities subject to compromise.

The following table summarizes the components of liabilities subject to compromise included in our consolidated balance sheets as of June 30, 2017 and December 31, 2016 :

	As of	
Thousands of dollars	**June 30, 2017**	**December 31, 2016**
Senior Unsecured Notes	$ 1,155,000	$ 1,155,000
Senior Secured Notes	650,000	650,000
Accrued interest payable	61,908	61,908
Accounts payable	4,899	5,294
Distributions payable	6,974	6,974
Total liabilities subject to compromise	$ 1,878,781	$ 1,879,176

Liquidity and Ability to Continue as a Going Concern

Although we believe our cash on hand, cash flow from operations and borrowings available under the DIP Credit Agreement will be adequate to meet the operating costs of our existing business, there are no assurances that we will have sufficient liquidity to continue to fund our operations or allow us to continue as a going concern until a plan of reorganization is confirmed by the Bankruptcy Court and becomes effective, and thereafter. Our long-term liquidity requirements, the adequacy of our capital resources and our ability to continue as a going concern are difficult to predict at this time and ultimately cannot be determined until a plan of reorganization has been confirmed, if at all, by the Bankruptcy Court. In addition, we have incurred and continue to incur significant professional fees and costs in connection with the administration of the Chapter 11 Cases, including the fees and expenses of the professionals retained by two statutory committees appointed in the Chapter 11 Cases. We are making adequate protection payments with respect to the lenders under the RBL Credit Agreement, consisting of the payment of interest (at the default rate) and the payment of all reasonable fees and expenses of professionals retained by our lenders, as provided for in the RBL Credit Agreement. We are also making adequate protection payments with respect to the Senior Secured Notes in the form of the payment of all reasonable fees and expenses of professionals retained by the holders of the Senior Secured Notes. We anticipate that we will continue to incur significant professional fees and costs during the pendency of the Chapter 11 Cases.

Given the uncertainty surrounding the Chapter 11 Cases, there is substantial doubt about our ability to continue as a going concern. The accompanying consolidated financial statements do not purport to reflect or provide for the consequences of the Chapter 11 Cases. In particular, the consolidated financial statements do not purport to show (i) as to assets, their realizable value on a liquidation basis or their fair value or their availability to satisfy liabilities; (ii) as to certain pre-petition liabilities, the amounts that may be allowed for claims or contingencies, or the status and priority thereof; (iii) as to unitholders' equity accounts, the effect of any changes that may be made in our capitalization; or (iv) as to operations, the effect of any changes that may be made to our business. While operating as debtors in possession under chapter 11 of the Bankruptcy Code, the Debtors may sell or otherwise dispose of or liquidate assets or settle liabilities in amounts other than those reflected in our consolidated financial statements, subject to the approval of the Bankruptcy Court or otherwise as permitted in the ordinary course of business. Further, a plan of reorganization could materially change the amounts and classifications in our historical consolidated financial statements.

In addition to the uncertainty resulting from the Chapter 11 Cases, oil and natural gas prices continue to remain low historically. During the six months ended June 30, 2014, 2015, 2016 and 2017, the WTI posted price averaged approximately $101 per Bbl, $53 per Bbl, $40 per Bbl and $50 per Bbl, respectively. During the six months ended June 30, 2014, 2015, 2016 and 2017, the Henry Hub posted price averaged approximately $4.89 per MMBtu, $2.82 per MMBtu, $2.07 per MMBtu and $3.05 per MMBtu. Our revenue, profitability and cash flow are highly sensitive to movements in oil and natural gas prices. Sustained depressed prices of oil and natural gas materially adversely affect our assets, development plans, results of operations and financial condition. The filing of the Chapter 11 Petitions triggered an event of default under each of the agreements governing our derivative transactions. As a result, our counterparties were permitted to terminate, and did terminate, all outstanding derivative transactions. As of June 30, 2017 , none of our estimated future production was covered by commodity derivatives, and we may not be able to enter into commodity derivatives covering our estimated future production on favorable terms or at all. As a result, we have significant exposure to fluctuations in oil and natural gas prices and our inability to hedge the risk of low commodity prices in the future, on favorable terms or at all, could have a material adverse impact on our business, results of operations and financial condition.

If our future sources of liquidity are insufficient, we could face substantial liquidity constraints and be unable to continue as a going concern and would likely be required to implement further cost reductions, significantly reduce, delay or eliminate capital expenditures, seek other financing alternatives or seek the sale of some or all of our assets. If we (i) continue to limit, defer or eliminate future capital expenditure plans, (ii) are unsuccessful in developing reserves and adding production through our capital program or (iii) implement cost-cutting efforts that are too overreaching, the value of our oil and natural gas properties and our financial condition and results of operations could be adversely affected. We have been managing our operating activities and liquidity carefully in light of the uncertainty regarding future oil and natural gas prices and the Chapter 11 Cases. To fund capital expenditures, we will be required to use cash on hand, cash generated from operations or borrowings under the DIP Credit Agreement, or some combination thereof.

3. 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. Historically, we have utilized derivative financial instruments to reduce this volatility.

Chapter 11 Cases

The filing of the Chapter 11 Petitions triggered an event of default under each of the agreements governing our derivative transactions ("ISDA Agreements"). As a result, our counterparties were permitted to terminate, and did terminate, all outstanding transactions governed by the ISDA Agreements. The termination date for each outstanding transaction is the termination date specified to us by our counterparties.

The derivative transactions are no longer accounted for at fair value under ASC 815, because they were terminated in connection with our filing of the Chapter 11 Petitions and have been evaluated as receivables or payables at termination value. At the termination dates, expected settlement receipts on terminated contracts were reclassified from current and long-term derivative instrument assets to accounts and other receivables, net on the consolidated balance sheets and expected settlement payments on terminated contracts were reclassified from current and long-term derivative instrument liabilities to other current liabilities on the consolidated balance sheets. At each of June 30, 2017 and December 31, 2016 , we had $460.0 million of estimated hedge settlements receivable and $4.1 million in estimated hedge settlements payable, reflected in accounts and other receivables, net and other current liabilities on the consolidated balance sheet, respectively.

On July 19, 2017, the Bankruptcy Court authorized the release of the Hedge Proceeds, to be applied to the payment of the Hedge Termination Obligations, with the remaining Hedge Proceeds to be applied as a dollar-for-dollar reduction of outstanding obligations under the RBL Credit Agreement. See Note 15 for information.

All of our derivative counterparties were lenders, or affiliates of lenders, under the RBL Credit Agreement (see Note 8). In connection with Bankruptcy Court approval of the DIP Credit Agreement, our counterparties were permitted to terminate, and did terminate, all outstanding derivative transactions and to calculate the amounts due to or from the Debtors as a result of such terminations, in accordance with the terms of the governing agreements. Each such counterparty was required to hold any proceeds due to the Debtors ("Hedge Proceeds") in a book entry account maintained by it pursuant to and subject to the provisions of the order of the Bankruptcy Court approving the DIP Credit Agreement, with the rights of all of the parties reserved as to the ultimate disposition of the proceeds.

Payables due to our counterparties ("Hedge Termination Obligations") with respect to our derivative obligations constituted secured obligations under the RBL Credit Agreement. Because the RBL Credit Agreement was fully collateralized at the Chapter 11 Filing Date, and is excluded from liabilities subject to compromise, settlements payable due to our counterparties were reflected in accounts payable on the consolidated balance sheet rather than in liabilities subject to compromise.

We had no gains or losses on derivative instruments during the three months and six months ended June 30, 2017 . The following table presents gains and losses on derivative instruments during the three months and six months ended June 30, 2016 :

Thousands of dollars	**Oil Commodity Derivatives (a)**	**Natural Gas Commodity Derivatives (a)**	**Interest Rate Derivatives (b)**	**Total Financial Instruments**
Three Months Ended June 30, 2016				
Net (loss) gain	$ (71,720)	$ (20,490)	$ 533	$ (91,677)
Six Months Ended June 30, 2016				
Net loss	$ (43,345)	$ (10,942)	$ (1,810)	$ (56,097)

(a) Included in 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 that are observable other than quoted prices that are included within 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 derivative instruments that trade in less liquid markets or contain limited observable model inputs are currently included in Level 3.

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 three months and six months ended June 30, 2017 and 2016 . 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.

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 tables set forth, by level within the hierarchy, the fair value of our financial instrument assets that were accounted for at fair value on a recurring basis. 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 June 30, 2017				
Available-for-sale securities				
Equities	1,620	—	—	1,620
Mutual funds	11,742	—	—	11,742
Exchange traded funds	8,181	—	—	8,181
Net assets	$ 21,543	$ —	$ —	$ 21,543

Thousands of dollars	Level 1	Level 2	Level 3	Total
As of December 31, 2016				
Available-for-sale securities				
Equities	1,492	—	—	1,492
Mutual funds	11,229	—	—	11,229
Exchange traded funds	7,675	—	—	7,675
Net assets	$ 20,396	$ —	$ —	$ 20,396

Credit and Counterparty Risk

Financial instruments that potentially subject us to concentrations of credit risk consist principally of accounts receivable, including hedge settlements receivable. Our hedge settlements receivable expose us to credit risk from counterparties. As of June 30, 2017 , our hedge settlements receivable were due from Bank of Montreal, Barclays Bank PLC, BNP Paribas, Canadian Imperial Bank of Commerce, Citibank, N.A, Comerica Bank, Credit Suisse Energy LLC, Credit Suisse International, ING Capital Markets LLC, Fifth Third Bank, JP Morgan Chase Bank N.A., Merrill Lynch Commodities, Inc., Morgan Stanley Capital Group Inc., PNC Bank, N.A, Royal Bank of Canada, The Bank of Nova Scotia, The Toronto-Dominion Bank, MUFG Union Bank N.A. and Wells Fargo Bank, N.A. All of our counterparties were lenders, or affiliates of lenders, under the RBL Credit Agreement. The RBL 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. 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 has been managed by diversifying our derivatives portfolio. As of June 30, 2017 , each of these financial institutions had an investment grade credit rating from Moody's Investors Service and Standard & Poor's.

On July 19, 2017, the Bankruptcy Court authorized the release of the Hedge Proceeds, to be applied to the payment of the Hedge Termination Obligations, with the remaining Hedge Proceeds to be applied as a dollar-for-dollar reduction of outstanding obligations under the RBL Credit Agreement. See Note 15 for more information.

4. Related Party Transactions

Breitburn Management Company LLC (“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. Breitburn Management also provided administrative services to Pacific Coast Energy Company LP (“PCEC”), our predecessor, under an administrative services agreement (as amended, the “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. PCEC and Breitburn Management agreed to terminate the Administrative Services Agreement effective June 30, 2016. Upon termination of the Administrative Services Agreement on June 30, 2016, PCEC was no longer considered a related party, as Breitburn Management and its management team no longer managed or had significant influence over PCEC. For the each of three months and six months ended June 30, 2016 , the monthly fee paid by PCEC for indirect expenses was $0.7 million . For the three months and six months ended June 30, 2016 , the monthly charges to PCEC for indirect expenses totaled $2.1 million and $4.2 million , and charges for direct expenses including payroll and administrative costs totaled $2.4 million and $4.4 million , respectively.

At June 30, 2017 and December 31, 2016 , we had receivables of $0.6 million and $0.9 million , respectively, due from certain of our other affiliates, representing investments in natural gas processing facilities, primarily for management fees and operational expenses incurred on their behalf.

On June 7, 2016, PCEC, Pacific Coast Energy Holdings LLC (“PCEH”) and PCEC (GP) LLC (collectively, the “PCEC Parties”) provided written notice to the Partnership, Breitburn GP LLC and Breitburn Management (collectively, the “Breitburn Parties”) of their intent to terminate the Omnibus Agreement, dated August 26, 2008, among the PCEC Parties and the Breitburn Parties (as amended, the “Omnibus Agreement”), effectively immediately. The Omnibus Agreement detailed rights between the PCEC Parties and the Breitburn Parties with respect to certain business opportunities. Pursuant to Section 4.12 of the Omnibus Agreement, either PCEH, on behalf of the PCEC Parties, or Breitburn Management, on behalf of the Breitburn Parties, had the right to terminate the Omnibus Agreement at such time as PCEC and Breitburn Management ceased to be under common management or upon the termination of the Administrative Services Agreement, which occurred on June 30, 2016, as discussed.

5. Impairments

Long-Lived Assets

We review our oil and gas properties for impairment periodically or when events or circumstances indicate that their carrying amounts may exceed their fair values and may not be recoverable. Under the successful efforts method of accounting, the carrying amount of an oil and gas property to be held and used is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the property. Due to the nature of the recoverability test, certain oil and gas properties may have carrying values which exceed their fair values, but an impairment charge is not recognized because their carrying values are less than their undiscounted cash flows. 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 assessing our oil and gas properties for potential impairment, management reviews the expected undiscounted future cash flows for our total proved and, in certain instances, risk-adjusted probable and possible reserves on a held and used basis based in large part on future capital and operating plans. The undiscounted cash flow review includes inputs such as applicable NYMEX forward strip prices, estimated basis price differentials, expenses and capital estimates, and escalation factors. Management also considers the impact future price changes are likely to have on our future operating plans.

Undiscounted future cash flows were forecast using applicable basis adjusted (i) nine-year NYMEX forward strip prices for oil, and (ii) ten-year NYMEX forward strip prices for natural gas, in each case, at the end of the reporting period, and escalated along with expenses and capital starting in (i) year ten for oil and (ii) year eleven for natural gas, 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 approximated 14% at June 30, 2017 and 13% at December 31, 2016 .

There were no impairments during the three months ended June 30, 2016. 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 plan.

At June 30, 2017 , the assumptions from our business plan were included in our impairment reserves analysis. For certain impaired fields, recent operating performance resulted in lower production estimates than previously forecast. Our business plan was prepared with the assumption that we emerge from Chapter 11 and continue to hold and use our assets for their economic lives up to and including final dispositions. Other assumptions and/or revisions in our business plan could result in material changes to the undiscounted cash flows used in our impairment analysis. Accordingly, we cannot estimate what impact, if any, other assumptions or courses of action or their probabilities of occurrence could have on our undiscounted cash flows at June 30, 2017 .

Non-cash impairment charges totaled $0.3 million for the three months ended June 30, 2017 , including $0.2 million in California and $0.1 million in the Southeast, primarily related to lower future production expected from certain lower margin properties. There were no impairments during the three months ended June 30, 2016.

Non-cash impairment charges totaled $17.2 million for the six months ended June 30, 2017 , including $11.9 million in the Rockies, $4.8 million in the Permian Basin, $0.3 million in the Southeast and $0.2 million in California, primarily related to the impact of the drop in commodity strip prices on projected future revenues of lower margin properties. Impairments totaled $2.8 million for the six months ended June 30, 2016 , including $2.1 million in the Southeast, $0.5 million in the Permian Basin, and $0.2 million in the Rockies.

Management prepared its undiscounted cash flow estimates on a held and used basis which assumes oil and gas properties will be held and used for their economic lives. If a decision is reached to sell a particular asset, that asset would be classified as held for sale and could potentially be impaired if the carrying value exceeded the estimated sales value less the costs of disposal. It is also possible that further periods of prolonged lower commodity prices, future declines in commodity prices, changes to our future plans in response to a final plan of reorganization, or increases in operating costs could result in future impairments. Additionally, the oil and gas assets may be further adjusted in the future due to the outcome of Chapter 11 Cases or adjusted to fair value if we are required to apply fresh start accounting upon emergence from Chapter 11.

6. Other Long-Term Assets

As of June 30, 2017 and December 31, 2016 , our other long-term assets were as follows:

	As of	
Thousands of dollars	**June 30, 2017**	**December 31, 2016**
Available-for-sale securities	$ 21,543	$ 20,396
Deposit for Jay Field net profit interest obligation	18,263	18,263
Property reclamation deposit	10,752	10,738
Other	15,311	14,449
Total	$ 65,869	$ 63,846

7. Debt

Our debt is detailed in the following table:

	As of	
Thousands of dollars	**June 30, 2017**	**December 31, 2016**
RBL Credit Agreement	$ 1,198,259	$ 1,198,259
Promissory note	2,938	2,938
Senior Secured Notes	650,000	650,000
2020 Senior Notes	305,000	305,000
2022 Senior Notes	850,000	850,000
Capital lease obligations	171	156
Total debt	$ 3,006,368	$ 3,006,353
Less: Current portion of debt	(1,198,259)	(1,198,259)
Less: Amounts reclassified to liabilities subject to compromise	(1,805,000)	(1,805,000)
Total long-term debt	$ 3,109	$ 3,094

DIP Credit Agreement

In connection with the Chapter 11 Cases, BOLP entered into the DIP Credit Agreement, as borrower, with the lenders party thereto (the "DIP Lenders") and Wells Fargo, National Association, as administrative agent. The other Debtors have guaranteed all obligations under the DIP Credit Agreement. Pursuant to the terms of the DIP Credit Agreement, the DIP Lenders made available a revolving credit facility in an aggregate principal amount of $150 million , which includes a letter of credit facility available for the issuance of letters of credit in an aggregate principal amount not to exceed a sublimit of $100 million , and a swingline facility in an aggregate principal amount not to exceed a sublimit of $5 million , in each case, to mature on the earlier to occur of (A) the effective date of a plan of reorganization in the Chapter 11 Cases or (B) the scheduled maturity of the DIP Credit Agreement of June 30, 2017. In addition, the maturity date may be accelerated upon the occurrence of certain events as set forth in the DIP Credit Agreement. On May 10, 2017, the Bankruptcy Court entered an order approving the Third Amendment to the DIP Credit Agreement, effective as of May 11, 2017. The Third Amendment, among other things, extended the DIP Credit Agreement's scheduled maturity date to September 30, 2017 and provided for the payment of certain fees to the Administrative Agent and the DIP Lenders.

The proceeds of the DIP Credit Agreement may be used: (i) to pay the costs and expenses of administering the Chapter 11 Cases, (ii) to fund our working capital needs, capital improvements, and other general corporate purposes, in each case, in accordance with an agreed budget and (iii) to provide adequate protection to existing secured creditors.

At June 30, 2017 and December 31, 2016 , we had no borrowings outstanding and $52.1 million and $37.9 million in letters of credit outstanding, respectively, under the DIP Credit Agreement.

Acceleration of Debt Obligations

The commencement of the Chapter 11 Cases resulted in the acceleration of the Debtors' obligations under the RBL Credit Agreement, the Senior Secured Notes, and the Senior Unsecured Notes. Any efforts to enforce such obligations are automatically stayed as a result of the filing of the Chapter 11 Petitions and the holders' rights of enforcement in respect of these obligations are subject to the applicable provisions of the Bankruptcy Code.

RBL Credit Agreement

BOLP, as borrower, and we and our wholly-owned subsidiaries, as guarantors, are party to 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 RBL Credit Agreement on November 19, 2014. The RBL Credit Agreement limited the amounts we could 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. At each of June 30, 2017 and December 31, 2016 , we had $1.2 billion in indebtedness outstanding under the RBL Credit Agreement.

At the Chapter 11 Filing Date, we had $1.2 billion in aggregate principal amount outstanding under the RBL Credit Agreement, the borrowing base was $1.8 billion and the aggregate commitment from lenders was $1.4 billion . The RBL Credit Agreement is secured by a first priority security interest in and lien on substantially all of the Debtors' assets, including the proceeds thereof and after-acquired property. We determined at the Chapter 11 Filing Date that the RBL Credit Agreement was fully collateralized. As a result of the automatic acceleration of our obligations under the RBL Credit Agreement as a consequence of the commencement of the Chapter 11 Cases, we reclassified the entire RBL Credit Agreement balance to current portion of long-term debt on the consolidated balance sheet. As of the Chapter 11 Filing Date, we recognized $15.7 million of interest expense for the full write-off of unamortized debt issuance costs related to the RBL Credit Agreement.

We are required to make adequate protection payments to the lenders under the RBL Credit Agreement, which includes the payment of interest (at the default rate) and the payment of all reasonable fees and expenses of professionals retained by our lenders, as provided for in the RBL Credit Agreement. We are recognizing the default interest accrued on the RBL Credit Agreement as interest expense, net of capitalized interest on the consolidated statements of operations, and we are recognizing the adequate protection payments as accrued interest payable on the consolidated balance sheets, and we are recognizing the adequate protection payments as accrued interest payable on the consolidated balance sheets, rather than in liabilities subject to compromise. At June 30, 2017 , the default interest rate on the RBL Credit Agreement was 7.5% .

The carrying value of the RBL Credit Agreement at June 30, 2017 and December 31, 2016 approximated fair value. We consider the fair value of the RBL Credit Agreement to be Level 2, as it is based on the current active market prime rate.

On July 19, 2017, the Bankruptcy Court authorized the release of the Hedge Proceeds, to be applied to the payment of the Hedge Termination Obligations, with the remaining Hedge Proceeds to be applied as a dollar-for-dollar reduction of outstanding obligations under the RBL Credit Agreement. See Note 15 for more information.

Senior Secured Notes

As of June 30, 2017 and December 31, 2016 , we had $650 million in aggregate principal amount of 9.25% Senior Secured Notes due 2020 outstanding. Prior to the commencement of the Chapter 11 Cases, interest on our Senior Secured Notes was payable quarterly in March, June, September and December.

Since the commencement of the Chapter 11 Cases on May 15, 2016, no interest has been paid to the holders of the Senior Secured Notes. As of June 30, 2017 , the Senior Secured Notes were reflected as liabilities subject to compromise on the consolidated balance sheet, with the carrying value equal to the face value of the notes of $650 million . In addition, as of the Chapter 11 Filing Date, the accrued but unpaid interest expense on the Senior Secured Notes of $7.5 million was reflected as liabilities subject to compromise. No interest expense was recognized on the Senior Secured Notes after the commencement of the Chapter 11 Cases. Unrecognized, contractual interest expense on the Senior Secured Notes for the three months and six months ended June 30, 2017 was $15.1 million and $30.1 million , respectively. Unrecognized, contractual interest expense on the Senior Secured Notes for each of the three months and six months ended June 30, 2016 was $7.5 million .

As a result of the filing of the Chapter 11 Cases, the fair value of our Senior Secured Notes at June 30, 2017 and December 31, 2016 cannot be reasonably determined.

Senior Unsecured Notes

As of June 30, 2017 and December 31, 2016 , we had $305.0 million in aggregate principal amount of 2020 Senior Notes and $850 million in aggregate principal amount of 2022 Senior Notes. Interest on the 2020 Senior Notes and the 2022 Senior Notes was payable twice a year in April and October.

As a consequence of the commencement of the Chapter 11 Cases on May 15, 2016, we did not pay $33.5 million in interest due with respect to our 2022 Senior Notes and $13.2 million interest due with respect to our 2020 Senior Notes, each of which were due on April 15, 2016

As of June 30, 2017 and December 31, 2016 , the Senior Unsecured Notes were reflected as liabilities subject to compromise on the consolidated balance sheet, with the carrying values equal to the face values. No interest expense has been recognized on the Senior Unsecured Notes subsequent to the filing of the Chapter 11 Petitions. Unrecognized contractual interest expense on the Senior Unsecured Notes for the three months and six months ended June 30, 2017 was $23.3 million and $46.6 million , respectively. Unrecognized contractual interest expense on the Senior Unsecured Notes for each of the three months and six months ended June 30, 2016 was $11.7 million .

As a result of the filing of the Chapter 11 Cases, the fair value of our Senior Unsecured Notes at June 30, 2017 and December 31, 2016 cannot be reasonably determined.

Interest Expense

Our interest expense is detailed as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands of dollars	**2017**	**2016**	**2017**	**2016**
RBL Credit Agreement (including commitment fees) and other debt	$ 23,024	$ 13,335	$ 45,105	$ 22,334
Senior Secured Notes	—	7,517	—	22,548
Senior Unsecured Notes	—	11,655	—	34,966
Amortization of net discount/premium and debt issuance costs	—	17,463	—	26,138
Capitalized interest	—	(53)	—	(80)
Total	$ 23,024	$ 49,917	$ 45,105	$ 105,906
Cash paid for interest	$ 24,693	$ 37,606	$ 65,559	$ 43,168

8. Condensed Consolidating Financial Statements

The Partnership and Breitburn Finance Corporation ("Breitburn Finance") (and BOLP, with respect to the Senior Secured Notes), as co-issuers, and certain of the Partnership's 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 the Senior Notes, and our only non-guarantor subsidiaries, Breitburn Collingwood Utica LLC 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 that does not guarantee the Senior Notes, is a wholly-owned finance subsidiary; all of our material subsidiaries are wholly-owned and have guaranteed the Senior Notes; and all of the guarantees are full, unconditional, joint and several.

Each guarantee of each 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 of 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 appropriate 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.

9. Asset Retirement Obligations

Asset retirement obligations ("ARO") are 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 of approximately 14% for the six months ended June 30, 2017 and for the year ended December 31, 2016 , 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 period ended June 30, 2017 , and the year ended December 31, 2016 are presented in the following table:

Thousands of dollars	Six Months Ended June 30, 2017	Year Ended December 31, 2016
Carrying amount, beginning of period	$ 258,494	$ 254,378
Liabilities added from acquisitions	49	78
Liabilities related to divested properties	—	(8,380)
Liabilities incurred from drilling	405	224
Liabilities settled	(3,735)	(3,162)
Revision of estimates	1,153	(2,362)
Accretion expense	8,864	17,718
Carrying amount, end of period	265,230	258,494
Less: Current portion of ARO	(5,031)	(5,905)
Non-current portion of ARO	$ 260,199	$ 252,589

10. Commitments and Contingencies

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 each of June 30, 2017 and December 31, 2016 , we had approximately $26.4 million of surety bonds. At June 30, 2017 and December 31, 2016 , we had zero and approximately $13.0 million , respectively, in letters of credit outstanding under the RBL Credit Agreement and approximately $52.1 million and $37.9 million , respectively, in letters of credit outstanding under the DIP Credit Agreement. The increase in letters of credit under the DIP Credit Agreement reflects the transfer of letters of credit from the RBL Credit Agreement to the DIP Credit Agreement.

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.

11. Partners' Equity

Under the priority scheme established by the Bankruptcy Code, unless creditors agree otherwise, pre-petition liabilities and post-petition liabilities must be satisfied in full before the holders of our Series A Preferred Units, Series B Preferred Units and Common Units are entitled to receive any distribution or retain any property under a plan of reorganization. The ultimate recovery to creditors and/or unitholders, if any, will not be determined until confirmation and implementation of a plan of reorganization. No assurance can be given as to what distributions, if any, will be made to each of these constituencies or the nature thereof. As discussed below, if certain requirements of the Bankruptcy Code are met, a plan of reorganization can be confirmed notwithstanding its rejection or deemed rejection by the holders of our Series A Preferred Units, Series B Preferred Units and Common Units and notwithstanding the fact that such holders do not receive or retain any property on account of their equity interests under the plan. Because of such possibilities, the value of our securities, including our Series A Preferred Units, Series B Preferred Units and Common Units, is highly speculative. We believe it is highly likely that our Series A Preferred Units, Series B Preferred Units and Common Units will be canceled in our Chapter 11 Cases and that the holders thereof will not receive any distribution on account of their holdings.

Preferred Units

As of June 30, 2017 and December 31, 2016 , we had 8.0 million Series A Preferred Units outstanding. 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.

As of June 30, 2017 and December 31, 2016 , we had 49.6 million Series B Preferred Units outstanding. The Series B Preferred Units rank senior to our Common Units and on parity with the Series A Preferred Units with respect to the payment of distributions.

On April 14, 2016, we elected to suspend the declaration of any further distributions on our Series A Preferred Units and Series B Preferred Units. We have not been accruing distributions on the Series A Preferred Units and Series B Preferred Units since the Chapter 11 Filing Date.

During the three months ended June 30, 2016 , we recognized $2.0 million of accrued distributions on the Series A Preferred Units, which were included in distributions to Series A preferred unitholders on the consolidated statements of operations. During three months ended June 30, 2016 , we recognized $3.7 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.

During the six months ended June 30, 2016 , we recognized $6.1 million of accrued distributions on the Series A Preferred Units, which were included in distributions to Series A preferred unitholders on the consolidated statements of operations. During six months ended June 30, 2016 , we recognized $11.1 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.

We will continue to account for our Series A Preferred Units and Series B Preferred Units at their carrying value until a plan of reorganization is confirmed by the Bankruptcy Court and becomes effective. We accrued for earned but undeclared distributions on each series of Preferred Units for the period from April 1, 2016 to the Chapter 11 Filing Date. As of June 30, 2017 and December 31, 2016 , total accrued but unpaid distributions on our Series A Preferred Units and Series B Preferred Units of $7.0 million were reflected as liabilities subject to compromise.

Common Units

As of the Chapter 11 Filing Date, we had 213.8 million Common Units outstanding. We will continue to account for our Common Units at their carrying value until a plan of reorganization is confirmed by the Bankruptcy Court and becomes effective.

At each of June 30, 2017 and December 31, 2016 , we had approximately 213.8 million of Common Units outstanding.

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. In prior periods, unvested restricted unit awards that earned non-forfeitable dividend rights qualified as participating securities and, accordingly, were included in the basic computation. Our unvested RPUs and convertible phantom units ("CPUs") participated in distributions on an equal basis with Common Units. Accordingly, the presentation below is prepared on a combined basis and is presented as net loss per common unit.

The following is a reconciliation of net loss and weighted average units for calculating basic net loss per common unit and diluted net loss per common unit.

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands, except per unit amounts	**2017**	**2016**	**2017**	**2016**
Net loss attributable to the partnership	$ (65,964)	$ (261,315)	$ (154,274)	$ (365,101)
Less:				
Distributions to Series A preferred unitholders	—	2,017	—	6,142
Non-cash distributions to Series B preferred unitholders	—	3,737	—	11,123
Net loss used to calculate basic and diluted net loss per unit	$ (65,964)	$ (267,069)	$ (154,274)	$ (382,366)
Weighted average number of units used to calculate basic and diluted net loss per unit (in thousands):				
Common Units (a)	213,789	213,779	213,789	213,720
Dilutive units (b)	—	—	—	—
Denominator for diluted net loss per unit	213,789	213,779	213,789	213,720
Net loss per common unit				
Basic	$ (0.31)	$ (1.25)	$ (0.72)	$ (1.79)
Diluted	$ (0.31)	$ (1.25)	$ (0.72)	$ (1.79)

(a) We had no participating securities outstanding during the three months and six months ended June 30, 2017 . The three months and six months ended June 30, 2016 exclude 20,429 and 19,222 , respectively, of weighted average anti-dilutive units from the calculation of the denominator for basic earnings per common unit, as we were in a loss position.

(b) We had no dilutive units outstanding during the three months and six months ended June 30, 2017 . Each of the three months and six months ended June 30, 2016 excludes 413 of weighted average anti-dilutive units from the calculation of the denominator for diluted earnings per common unit, as we were in a loss position.

12. Accumulated Other Comprehensive Loss

Changes in accumulated other comprehensive loss by component, net of tax, were as follows:

	Three Months Ended June 30,					
	2017			2016		
	Gain (loss) on			Gain (loss) on		
Thousands of dollars	Available-For-Sale Securities	Post- retirement Benefits	Total	Available-For-Sale Securities	Post retirement Benefits	Total
Accumulated comprehensive income (loss), beginning of period	$ 772	$ 774	$ 1,546	$ (72)	$ 121	$ 49
Other comprehensive (loss) income before reclassification	(169)	1	(168)	327	(781)	(454)
Amounts reclassified from accumulated other comprehensive loss (a)	11	—	11	(64)	—	(64)
Net current period other comprehensive (loss) income	(158)	1	(157)	263	(781)	(518)
Less: Accumulated comprehensive (loss) income attributable to noncontrolling interest	(65)	1	(64)	107	(319)	(212)
Accumulated comprehensive income (loss), end of period	$ 679	$ 774	$ 1,453	$ 84	$ (341)	$ (257)

	Six Months Ended June 30,					
	2017			2016		
	Gain (loss) on			Gain (loss) on		
Thousands of dollars	Available-For-Sale Securities	Post- retirement Benefits	Total	Available-For-Sale Securities	Post- retirement Benefits	
Accumulated comprehensive income (loss), beginning of period	$ 234	$ 798	$ 1,032	$ (350)	$ 121	$ (229)
Other comprehensive income (loss) before reclassification	745	(41)	704	1,209	(781)	428
Amounts reclassified from accumulated other comprehensive loss (a)	6	—	6	(476)	—	(476)
Net current period other comprehensive income (loss)	751	(41)	710	733	(781)	(48)
Less: Accumulated comprehensive income (loss) attributable to noncontrolling interest	306	(17)	289	299	(319)	(20)
Accumulated comprehensive income (loss), end of period	$ 679	$ 774	$ 1,453	$ 84	$ (341)	$ (257)

(a) Amounts were reclassified from accumulated other comprehensive loss to other (income) expense, net on the consolidated statements of operations.

13. Incentive Compensation Plans

For detailed information on our various compensation plans that were in place during and prior to 2016, see Note 16 to the consolidated financial statements included in our 2016 Annual Report. Our two remaining incentive compensation plans, detailed below, are paid in cash.

Key Employee Program

In March 2017, the Bankruptcy Court approved the Partnership's 2017 Key Employee Program ("KEP"). The KEP has substantially similar terms and conditions as the Partnership's 2016 Key Employee Program, which was approved by the Bankruptcy Court in September 2016. Payments under the KEP are contingent on the Partnership meeting certain performance metrics tied to production and lease operating expense for fiscal year 2017. Participants must be employed on the scheduled payment dates in order to receive a payment under the KEP. During the three months and six months ended June 30, 2017 , we recognized $2.5 million and $5.2 million in general and administrative expenses, and $1.1 million and $2.7 million in operating costs, related to the KEP, respectively.

Key Executive Incentive Program

In March 2017, the Bankruptcy Court approved the Partnership's 2017 Key Executive Incentive Program ("KEIP"). Participants in the KEIP include the following named executive officers of Breitburn GP LLC, the general partner of the Partnership: Halbert S. Washburn, Mark L. Pease, James G. Jackson and Gregory C. Brown. The KEIP has substantially similar terms and conditions as the Partnership's 2016 Key Executive Incentive Program, except for the use of updated metrics and the modification of the timing of award payments so that the payments are made at the conclusion of each quarterly performance period ending March 31, June 30, September 30 and December 31, 2017. The 2016 Key Executive Incentive Program was approved by the Bankruptcy Court in September 2016. Payments under the KEIP are contingent on the Partnership meeting the same performance metrics utilized in the KEP. Participants must be employed on the scheduled payment dates in order to receive a payment under the KEIP. During the three months and six months ended June 30, 2017 , we recognized $1.8 million and $3.6 million general and administrative expenses, respectively, related to the KEIP.

14. Restructuring Costs

During the three months and six months ended June 30, 2016 , we executed workforce reduction plans as part of company-wide reorganization efforts intended to reduce costs, due in part to lower commodity prices. In addition, we executed workforce reductions in the first half of 2016 in connection with the notice received from PCEC in February 2016 of its intention to terminate the administrative services agreement with Breitburn Management, effective as of June 30, 2016 (see Note 4 for a discussion of the administrative services agreement).

In connection with the reductions in workforce, we incurred total costs of approximately $2.4 million and $5.2 million for the three months and six months ended June 30, 2016 , respectively, which included severance cash payments, accelerated vesting of LTIP grants for certain individuals and other employee-related termination costs. The reductions were communicated to affected employees on various dates during the six months ended June 30 2016, and all such notifications were completed by June 30, 2016. The plan resulted in a reduction of 12 and 69 employees for the three months and six months ended June 30, 2016 , respectively. There were no workforce reduction plans during the three months and six months ended June 30, 2017 .

Thousands of dollars	**Three Months Ended June 30, 2016**	**Six Months Ended June 30, 2016**
Severance payments	$ 1,508	$ 3,451
Unit-based compensation expense	806	1,444
Other termination costs	125	353
Total	$ 2,439	$ 5,248

15. Subsequent Events

On July 19, 2017, the Bankruptcy Court authorized the release of the Hedge Proceeds, to be applied to the payment of $4.1 million in Hedge Termination Obligations, with the remaining $460.0 million in Hedge Proceeds to be applied as a dollar-for-dollar reduction of outstanding obligations under the RBL Credit Agreement. We reduced the aggregate principal amount outstanding under the RBL Credit Agreement by $452.2 million , and as of August 8, 2017, we had approximately $746.1 million in aggregate principal amount outstanding under the RBL Credit Agreement.

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion and analysis should be read in conjunction with Management's Discussion and Analysis in Part II—Item 7 of our 2016 Annual Report and the consolidated financial statements and related notes therein. Our 2016 Annual Report contains a discussion of other matters not included herein, such as disclosures regarding critical accounting policies and estimates and contractual obligations. The following discussion and analysis should also be read together with Part II—Item 1A "—Risk Factors" of this report, the "Cautionary Statement Regarding Forward-Looking Information" in this report and in our 2016 Annual Report and Part I—Item 1A "—Risk Factors" of our 2016 Annual Report.

Overview

We are an independent oil and gas partnership focused on the exploitation and development of oil, natural gas liquids ("NGL") and natural gas properties in the United States. 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. Our assets consist primarily of producing and non-producing oil, NGL and natural gas reserves located in the following producing areas: (i) the Permian Basin in Texas and New Mexico, (ii) Midwest (Michigan, Indiana, and Kentucky), (iii) Ark-La-Tex (Arkansas, Louisiana and East Texas), (iv) Mid-Continent (Oklahoma), (v) the Rockies (Wyoming and Colorado), (vi) California, and (vii) Southeast (Florida and Alabama).

Prior to the decline in commodity prices and the filing of the Chapter 11 Cases, our core investment strategy 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 response to the steep and continued decline in commodity prices during 2014, 2015 and the first part of 2016, we adjusted our business strategies by suspending distributions to common and preferred unitholders, significantly reducing our capital budget, cutting operating and overhead costs, scaling back derivative activity and reducing our acquisition expectations. Sustained low commodity prices eventually led to the filing of the Chapter 11 Petitions, as described below.

Chapter 11 Cases

On May 15, 2016, the Debtors filed the Chapter 11 Petitions. The Chapter 11 Cases are being administered jointly under the caption "In re Breitburn Energy Partners LP, et al.," Case No. 16-11390 . The Debtors include the Partnership, Breitburn Management, BOLP, Breitburn Finance, Breitburn GP LLC, Breitburn Operating GP LLC, Breitburn Sawtelle LLC, Breitburn Oklahoma LLC, Phoenix Production Company, QR Energy, LP, QRE GP, LLC, QRE Operating, LLC, Breitburn Transpetco LP LLC, Breitburn Transpetco GP LLC, Transpetco Pipeline Company, L.P., Terra Energy Company LLC, Terra Pipeline Company LLC, Breitburn Florida LLC, Mercury Michigan Company, LLC, Beaver Creek Pipeline, L.L.C., GTG Pipeline LLC and Alamitos Company. No trustee has been appointed and we continue to manage the Partnership and our affiliates and operate our businesses as "debtors in possession" subject to the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. To assure ordinary course operations, we received approval from the Bankruptcy Court on a variety of "first day" motions, including motions that authorize us to maintain our existing cash management system, to secure debtor-in-possession financing and other customary relief. In August 2016, the Bankruptcy Court entered a final order approving the DIP Credit Agreement. In December 2016, the Bankruptcy Court entered an order approving an extension of the DIP Credit Agreement to June 30, 2017. On May 10, 2017, the Bankruptcy Court entered an order approving the Third Amendment to the DIP Credit Agreement, effective as of May 11, 2017. The Third Amendment, among other things, extended the DIP Credit Agreement's scheduled maturity date to September 30, 2017 and provided for the payment of certain fees to the Administrative Agent and the DIP Lenders.

The commencement of the Chapter 11 Cases resulted in the acceleration of the Debtors' obligations under the RBL Credit Agreement and the indentures governing the Senior Secured Notes and Senior Unsecured Notes. Any efforts to enforce such obligations are automatically stayed as a result of the filing of the Chapter 11 Petitions and the holders' rights of enforcement in respect of these obligations are subject to the applicable provisions of the Bankruptcy Code. We are making adequate protection payments with respect to the RBL Credit Agreement, consisting of the payment of interest (at the default rate) and the payment of all reasonable fees and expenses of professionals retained by our lenders, as provided for in the RBL Credit

Agreement. We are also making adequate protection payments with respect to the Senior Secured Notes in the form of the payment of all reasonable fees and expenses of professionals retained by the holders of the Senior Secured Notes.

The commencement of the Chapter 11 Cases constituted an event of default under our commodity and interest rate derivative instruments, resulting in a termination right by our counterparties. All of our counterparties exercised this termination right during the year ended December 31, 2016, and the terminated transactions are reflected in accounts and other receivables, net and other current liabilities on the consolidated balance sheets at June 30, 2017 and December 31, 2016 . The termination of these transactions has since exposed our cash flows to fluctuations in commodity prices. The terminated derivative instruments resulted in estimated settlements receivable and payable of $460.0 million and $4.1 million , respectively, at each of June 30, 2017 and December 31, 2016 . On July 19, 2017, the Bankruptcy Court authorized the release of the Hedge Proceeds, to be applied to the payment of $4.1 million in Hedge Termination Obligations, with the remaining $460.0 million in Hedge Proceeds to be applied as a dollar-for-dollar reduction of outstanding obligations under the RBL Credit Agreement. As of August 8, 2017, we had approximately $ 746.1 million in aggregate principal amount outstanding under the RBL Credit Agreement. See Note 15 to the consolidated financial statements in this report for more information.

We have incurred and will continue to incur significant costs associated with the reorganization in connection with the Chapter 11 Cases. These costs are being expensed as incurred, and are expected to significantly affect our results. Reorganization items, net on the consolidated statements of operations include professional expenses, gains and losses that are the result of the reorganization and restructuring of the business, and deferred and unamortized financing costs related to the Senior Notes. Reorganization items, net totaled $10.2 million and $20.5 million for the three months and six months ended June 30, 2017 , respectively, and $66.9 million for each of the three months and six months ended June 30, 2016 . For more information relating to the Chapter 11 Cases, see Note 2 to the consolidated financial statements in this report.

Process for Plan of Reorganization . In order to successfully emerge from Chapter 11, the Debtors will need to obtain confirmation by the Bankruptcy Court of a plan of reorganization that satisfies the requirements of the Bankruptcy Code. A plan of reorganization generally provides for how pre-petition obligations and equity interests will be treated in satisfaction and discharge thereof, and provides for the means by which the plan of reorganization will be implemented.

Fresh Start Accounting . We may be required to adopt fresh start accounting upon emergence from Chapter 11. Adopting fresh start accounting would result in the allocation of the reorganization value to individual assets based on their estimated fair values. The enterprise value of the equity of the emerging company is based on several assumptions and inputs contemplated in the future projections of the plan of reorganization and are subject to significant uncertainties. We currently cannot estimate the potential financial effect of fresh start accounting on our consolidated financial statements upon the emergence from Chapter 11, although we would expect to recognize material adjustments upon implementation of fresh start accounting guidance upon emergence pursuant to a plan of reorganization. The assumptions for which there is a reasonable possibility of material impact affecting the reorganization value include, but are not limited to, management's assumptions and capital expenditure plans related to the estimation of our oil and gas reserves.

Distributions

Through March 31, 2016, we paid 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, totaling $4.1 million for the three months ended March 31, 2016. Through March 31, 2016, we elected to pay our Series B Preferred Unit distributions in kind by issuing additional Series B Preferred Units (or, when elected by the unitholder, by issuing Common Units in lieu of such Series B Preferred Units) instead of cash. During the three and six months ended March 31, 2016, we declared distributions on our Series B Preferred Units of 0.006666 Series B Preferred Unit per unit in the form of 0.8 million Series B Preferred Units and 0.2 million Common Units.

On April 14, 2016, we elected to suspend the declaration of any further distributions on our Preferred Units. In the event the Partnership fails to make any distribution on the Series B Preferred Units as required under the partnership agreement, the annual distribution rate is increased by 2.00% effective as of such date until the date on which all required distributions have been made. We accrued for earned but undeclared distributions on each series of Preferred Units for the period from April 15, 2016 to the Chapter 11 Filing Date. As of June 30, 2017 , the accrued but unpaid distributions of $7.0 million were reflected as liabilities subject to compromise.

Operational Focus and Capital Expenditures

In the first six months of 2017 , our capital expenditures for oil and gas activities, including capitalized engineering costs, totaled $46 million , compared to approximately $32 million in the first six months of 2016 . We spent approximately $15 million in Ark-La-Tex, $9 million in the Permian Basin, $8 million in Mid-Continent, $7 million in the Southeast, $4 million in California, $2 million in the Midwest, and $1 million in the Rockies. In the first six months of 2017 , we drilled and completed three net productive wells and performed thirteen net recompletions in Ark-La-Tex, drilled and completed one net productive well and performed seven net recompletions in the Permian Basin, drilled and completed one net productive well and four net recompletions in the Southeast, and performed seven net recompletions in California and one in Mid-Continent.

We expect our full year 2017 capital spending program for oil and gas activities, including capitalized engineering costs and excluding acquisitions, to be approximately $110 million . 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 Ark-La-Tex, the Permian Basin and Mid-Continent that are designed to increase or add to production or reserves.

Commodity Prices

Our revenues and net income are sensitive to oil, NGL and natural gas prices, which have been and are expected to continue to be highly volatile.

In the second quarter of 2017 , the NYMEX WTI spot price averaged $48 per barrel, compared with approximately $45 per barrel in the second quarter of 2016 . In the first six months of 2017 , the NYMEX WTI spot price ranged from a low of $42 per barrel to a high of $54 per barrel. In the first six months of 2016 , the NYMEX WTI spot price ranged from a low of $26 per barrel to a high of $51 per barrel.

In the second quarter of 2017 , the Henry Hub natural gas spot price averaged $3.08 per MMBtu compared with approximately $2.15 per MMBtu in the second quarter of 2016 . In the first six months of 2017 , the Henry Hub natural gas spot price ranged from a low of $2.44 per MMBtu to a high of $3.71 per MMBtu. In the first six months of 2016 , the Henry Hub spot price ranged from a low of $1.49 per MMBtu to a high of $2.94 per MMBtu. In the second quarter of 2017 , the MichCon natural gas spot price averaged $3.11 per MMBtu compared with approximately $1.99 per MMBtu in the second quarter of 2016 . In the first six months of 2017 , the MichCon natural gas spot price averaged $3.23 per MMBtu compared with approximately $2.09 per MMBtu in the first six months of 2016 .

Sustained low commodity prices have negatively impacted revenues, earnings and cash flows, and will have a material adverse effect on our liquidity position. We expect that further declines in commodity prices, or continued low commodity prices, will not only decrease our revenues, but will also reduce the amount of crude oil and natural gas that we can produce economically, which will lower our crude oil and natural gas reserves.

The continued volatility and sustained low oil and natural gas prices increase the uncertainty as to the impact of commodity prices on our estimated proved reserves. We are unable to predict future commodity prices with any greater precision than the futures market. Changing commodity prices, whether lower or higher, can have a significant impact on the volumetric quantities of our proved reserve portfolio.

We recorded non-cash oil and natural gas asset impairment charges of $0.3 million and $17.2 million during the three months and six months ended June 30, 2017 , respectively, and $283.3 million during the twelve months ended December 31, 2016 . 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.

When testing properties for impairment, none of our oil and gas properties that were not impaired had undiscounted cash flows which exceeded the net book value by less than 5% . Given the number of assumptions involved in the estimates, estimates as to sensitivities to earnings for these periods if other assumptions had been used in impairment reviews and calculations is not practicable. Favorable changes to some assumptions could have increased the undiscounted cash flows thus further avoiding the need to impair any assets in this period, whereas other unfavorable changes could have caused an unknown number of assets to become impaired. Additionally, the oil and gas assets may be further adjusted in the future due to the outcome of Chapter 11 Cases or adjusted to fair value if we are required to apply fresh start accounting upon emergence from Chapter 11.

Breitburn Management

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.

Results of Operations

The table below summarizes certain of our results of operations for the periods indicated. The data for the periods reflect our results as they are presented in our unaudited consolidated financial statements included elsewhere in this report.

Thousands of dollars, except as indicated	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Increase/(Decrease)	%	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Increase/(Decrease)	%
Total production (MBoe) (a)	4,164	4,606	(442)	(10)%	8,292	9,454	(1,162)	(12)%
Oil (MBbl)	2,146	2,378	(232)	(10)%	4,316	4,967	(651)	(13)%
NGLs (MBbl)	440	513	(73)	(14)%	877	1,011	(134)	(13)%
Natural gas (MMcf)	9,469	10,288	(819)	(8)%	18,591	20,855	(2,264)	(11)%
Average daily production (Boe/d)	45,758	50,615	(4,857)	(10)%	45,812	51,945	(6,133)	(12)%
Sales volumes (MBoe) (b)	4,234	4,644	(410)	(9)%	8,439	9,571	(1,132)	(12)%
Average realized sales price (per Boe) (c)	$ 32.29	$ 27.41	$ 4.88	18 %	$ 33.65	$ 24.32	$ 9.33	38 %
Oil (per Bbl)	44.93	41.42	3.51	8 %	46.57	35.11	11.46	33 %
NGLs (per Bbl)	19.93	15.22	4.71	31 %	21.09	13.05	8.04	62 %
Natural gas (per Mcf)	3.00	1.87	1.13	60 %	3.10	1.96	1.14	58 %
Oil sales	99,564	100,206	(642)	(1)%	207,837	178,564	29,273	16 %
NGL sales	8,768	7,809	959	12 %	18,496	13,191	5,305	40 %
Natural gas sales	28,371	19,267	9,104	47 %	57,646	40,977	16,669	41 %
Loss on commodity derivative instruments	—	(92,210)	92,210	(100)%	—	(54,287)	54,287	(100)%
Other revenues, net (d)	4,406	4,362	44	1 %	8,860	8,955	(95)	(1)%
Total revenues	141,109	39,434	101,675	258 %	292,839	187,400	105,439	56 %
Lease operating expenses before taxes (e)	77,177	68,505	8,672	13 %	158,901	148,347	10,554	7 %
Production and property taxes (f)	9,883	10,542	(659)	(6)%	20,495	20,451	44	— %
Total lease operating expenses	87,060	79,047	8,013	10 %	179,396	168,798	10,598	6 %
Purchases and other operating costs	3,829	1,345	2,484	185 %	9,000	3,963	5,037	127 %
Salt water disposal costs	2,669	3,355	(686)	(20)%	5,701	6,335	(634)	(10)%
Change in inventory	166	48	118	246 %	(585)	(327)	(258)	79 %
Total operating costs	93,724	83,795	9,929	12 %	193,512	178,769	14,743	8 %
Lease operating expenses before taxes per Boe (g)	18.53	14.74	3.79	26 %	19.16	15.53	3.63	23 %
Production and property taxes per Boe	2.37	2.29	0.08	3 %	2.47	2.16	0.31	14 %
Total lease operating expenses per Boe	20.90	17.03	3.87	23 %	21.63	17.69	3.94	22 %
Depletion, depreciation and amortization (“DD&A”)	63,197	81,960	(18,763)	(23)%	136,561	165,683	(29,122)	(18)%
DD&A per Boe	15.18	17.79	(2.61)	(15)%	16.47	17.53	(1.06)	(6)%
Impairment of oil and natural gas properties	321	—	321	n/a	17,211	2,793	14,418	n/a
G&A excluding unit-based compensation (h)(i)	17,197	12,928	4,269	33 %	34,769	30,544	4,225	14 %
G&A excluding unit-based compensation per Boe (j)	$ 4.13	$ 2.81	$ 1.32	47 %	$ 4.19	$ 3.23	$ 0.96	30 %

(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) Includes 75 MBoe and 31 MBoe of condensate purchased from third parties during the three months ended June 30, 2017 and 2016, respectively, and 168 MBoe and 121 MBoe of condensate purchased from third parties during the six months ended June 30, 2017 and 2016, respectively.

(c) Excludes the effect of commodity derivative settlements.

(d) Includes salt water disposal revenues, gas processing fees, earnings from equity investments and other operating revenues.

(e) Includes district expenses, transportation expenses and processing fees.

(f) Includes ad valorem and severance taxes.

(g) Excludes non-cash unit-based compensation expense of zero and $0.6 million for the three months ended June 30, 2017 and 2016, and zero and $1.5 million for the six months ended June 30, 2017 and 2016, respectively.

(h) Excludes non-cash unit-based compensation expense of zero and $3.3 million for the three months ended June 30, 2017 and 2016, and zero and $7.1 million for the six months ended June 30, 2017 and 2016, respectively.

(i) G&A expenses, excluding cash and non-cash unit-based incentive compensation, were $12.2 million and $8.3 million for the three months ended June 30, 2017 and 2016, and $24.5 million and $22.4 million for the six months ended June 30, 2017 and 2016, respectively.

(j) G&A expenses per Boe, excluding cash and non-cash unit-based incentive compensation, were $2.92 and $1.80 for the three months ended June 30, 2017 and 2016, and $2.96 and $2.37 for the six months ended June 30, 2017 and 2016, respectively.

Comparison of Results for the Three Months and Six Months Ended June 30, 2017 and 2016

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

Production

For the three months ended June 30, 2017 , total production was 4,164 MBoe compared to 4,606 MBoe for the three months ended June 30, 2016 , a decrease of 10% , primarily due to lower oil production from our Ark-La-Tex, Mid-Continent, Rockies and Permian Basin properties due to natural field declines.

For the six months ended June 30, 2017 , total production was 8,292 MBoe compared to 9,454 MBoe for the six months ended June 30, 2016 , a decrease of 12% , primarily due to lower oil production from our Mid-Continent, Ark-La-Tex, Rockies and Permian Basin properties due to natural field declines.

Oil, NGL and natural gas sales

Total oil, NGL and natural gas sales revenues increased $9.4 million for the three months ended June 30, 2017 , compared to the three months ended June 30, 2016 . Crude oil revenues decreased $0.6 million due to lower sales volume for the three months ended June 30, 2017 compared to the three months ended June 30, 2016 , although crude oil prices were higher on average during the current period. NGL revenues increased $1.0 million primarily due to higher average NGL prices, partially offset by lower production for the three months ended June 30, 2017 compared to the three months ended June 30, 2016 . Natural gas revenues increased $9.1 million , primarily due to higher average natural gas prices, partially offset by lower production for the three months ended June 30, 2017 compared to the three months ended June 30, 2016 .

Realized prices for crude oil increased $3.51 per Boe, or 8% , for the three months ended June 30, 2017 compared to the three months ended June 30, 2016 . Realized prices for NGLs increased $4.71 per Boe, or 31% for the three months ended June 30, 2017 compared to the three months ended June 30, 2016 . Realized prices for natural gas increased $1.13 per Mcf, or 60% , for the three months ended June 30, 2017 compared to the three months ended June 30, 2016 .

Total oil, NGL and natural gas sales revenues increased $51.2 million for the six months ended June 30, 2017 , compared to the six months ended June 30, 2016 . Crude oil revenues increased $29.3 million due to higher average crude oil prices, partially offset by lower sales volume for the six months ended June 30, 2017 compared to the six months ended June 30, 2016 . NGL revenues increased $5.3 million primarily due to higher average NGL prices, partially offset by lower production for the six months ended June 30, 2017 compared to the six months ended June 30, 2016 . Natural gas revenues increased $16.7 million primarily due to higher average natural gas prices, partially offset by lower production for the six months ended June 30, 2017 compared to the six months ended June 30, 2016 .

Realized prices for crude oil increased $11.46 per Boe, or 33% , for the six months ended June 30, 2017 compared to the six months ended June 30, 2016 . Realized prices for NGLs increased $8.04 per Boe, or 62% for the six months ended June 30, 2017 compared to the six months ended June 30, 2016 . Realized prices for natural gas increased $1.14 per Mcf, or 58% , for the six months ended June 30, 2017 compared to the six months ended June 30, 2016 .

Loss on commodity derivative instruments

The filing of the Chapter 11 Petitions triggered an event of default under each of our ISDA Agreements and, as a result, our counterparties were permitted to terminate, and did terminate, all outstanding transactions governed by the ISDA Agreements during 2016. Loss on commodity derivative instruments for the three months ended June 30, 2016 was $92.2 million . Oil and natural gas derivative instrument settlement receipts net of payments totaled $476.2 million for the three months ended June 30, 2016 . Mark-to-market loss on commodity derivative instruments for the three months ended June 30, 2016 was $568.4 million , primarily due to contracts that settled during the period, partially offset by a decrease in commodity futures prices during the period.

Loss on commodity derivative instruments for the six months ended June 30, 2016 was $54.3 million . Oil and natural gas derivative instrument settlement receipts net of payments totaled $611.5 million for the six months ended June 30, 2016 . Mark-to-market loss on commodity derivative instruments for the six months ended June 30, 2016 was $665.8 million , primarily due to contracts that settled during the period partially offset by a decrease in commodity future prices during the period.

Other revenues, net

Other revenues increased less than $0.1 million for the three months ended June 30, 2017 compared to the three months ended June 30, 2016 , primarily due to higher salt water disposal income.

Other revenues decreased $0.1 million for the six months ended June 30, 2017 compared to the six months ended June 30, 2016 , primarily due to lower sulfur sales and lower rental income partially offset by higher salt water disposal income.

Lease operating expenses

Pre-tax lease operating expenses, including district expenses, transportation expenses and processing fees, for the three months ended June 30, 2017 increased $8.7 million compared to the three months ended June 30, 2016 . The increase in pre-tax lease operating expenses primarily reflects higher well services, bringing additional wells on production, and the effect that increased commodity prices had on operating costs. On a per Boe basis, pre-tax lease operating expenses excluding non-cash unit based compensation expense were 26% higher than the three months ended June 30, 2016 at $18.53 per Boe, primarily due to higher well services and the impact that lower production volumes and higher commodity prices had on our operating costs per Boe.

Production and property taxes for the three months ended June 30, 2017 totaled $9.9 million , which was $0.7 million lower than the three months ended June 30, 2016 , primarily due to lower production volumes. On a per Boe basis, production and property taxes for the three months ended June 30, 2017 were $2.37 per Boe, which was 3% higher than the three months ended June 30, 2016 , primarily due to higher commodity prices.

Pre-tax lease operating expenses, including district expenses, transportation expenses and processing fees, for the six months ended June 30, 2017 increased $10.6 million compared to the six months ended June 30, 2016 . The increase in pre-tax lease operating expenses primarily reflects higher well services, bringing additional wells on production, and the effect that increased commodity prices had on operating costs. On a per Boe basis, pre-tax lease operating expenses excluding non-cash unit based compensation expense were 23% higher than the six months ended June 30, 2016 at $19.16 per Boe, primarily due to higher well services and the impact that lower production volumes and higher commodity prices had on our operating costs per Boe.

Production and property taxes for the six months ended June 30, 2017 totaled $20.5 million , which was less than $0.1 million higher than the six months ended June 30, 2016 , primarily due to higher commodity prices, offset by lower production volumes. On a per Boe basis, production and property taxes for the six months ended June 30, 2017 were $2.47 per Boe, which was 14% higher than the six months ended June 30, 2016 , primarily due to higher commodity prices.

Change in inventory

In Florida, our crude oil sales are a function of the number and size of crude oil shipments in each quarter, and thus crude oil sales do not always coincide with volumes produced in a given period. Sales occur on average every 12 to 14 weeks. We match production expenses with crude oil sales. Production expenses associated with unsold crude 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.

For the three months ended June 30, 2017 , the change in inventory account amounted to a charge of $0.2 million compared to a charge of less than $0.1 million during the same period in 2016 . The charge to inventory during the three months ended June 30, 2017 primarily reflects a slight increase in cost of goods sold during the period. The charge to inventory during the three months ended June 30, 2016 primarily reflects a higher volume of crude oil sold than produced during the period. In the three months ended June 30, 2017 , we sold 132 gross MBbls and produced 137 gross MBbls of crude oil from our Florida operations.

For the six months ended June 30, 2017 , the change in inventory account amounted to a credit of $0.6 million compared to a credit of $0.3 million during the same period in 2016 . The credits to inventory during the six months ended June 30, 2017 and June 30, 2016 primarily reflect a higher volume of crude oil produced than sold during each period. In the six months ended June 30, 2017 , we sold 243 gross MBbls and produced 265 gross MBbls of crude oil from our Florida operations.

Depletion, depreciation and amortization

DD&A totaled $63.2 million , or $15.18 per Boe, during the three months ended June 30, 2017 , a decrease of approximately 15% per Boe from the same period a year ago. The decrease in DD&A per Boe compared to the three months ended June 30, 2016 was primarily due to the effect the impairments of proved properties during the first half of 2017 and the year ended December 31, 2016 had on our reserve volumes and DD&A rates.

DD&A totaled $136.6 million , or $16.47 per Boe, during the six months ended June 30, 2017 , a decrease of approximately 6% per Boe from the same period a year ago. The decrease in DD&A per Boe compared to the six months ended June 30, 2016 was primarily due to the effect the impairments of proved properties during the first half of 2017 and the year ended December 31, 2016 had on our reserve volumes and DD&A rates.

Impairments

Impairments of proved properties totaled $0.3 million for the three months ended June 30, 2017 , including in $0.2 million in California and $0.1 million in the Southeast, primarily related to lower future production expected from certain of our lower margin properties. There were no impairments during the three months ended June 30, 2016 .

Impairments of proved properties totaled $17.2 million for the six months ended June 30, 2017 , including $11.9 million in the Rockies, $4.8 million in the Permian Basin, $0.3 million in the Southeast, $0.2 million in California, primarily related to the impact of the drop in commodity strip prices on projected future revenues of our lower margin properties. During the six months ended June 30, 2016 , impairments of proved properties totaled $2.8 million , including $2.1 million in the Southeast, $0.5 million in the Permian Basin and $0.2 million in the Rockies, primarily related to the impact of lower commodity strip prices on projected future revenues of certain lower margin properties.

General and administrative expenses

General and administrative (“G&A”) expenses totaled $17.2 million and $16.3 million for the three months ended June 30, 2017 and 2016 , respectively. The three months ended June 30, 2016 included $3.4 million in non-cash unit-based incentive compensation expense. The three months ended June 30, 2017 and 2016 included $5.0 million and $4.6 million in cash-based incentive compensation, respectively. G&A expenses, excluding cash and non-cash incentive compensation, were $12.2 million and $8.3 million for the three months ended June 30, 2017 and 2016 , respectively. The increase in G&A, excluding cash and non-cash incentive compensation, during the three months ended June 30, 2017 was primarily due to lower management fee income due to the termination of the Administrative Services Agreement with PCEC. On a per Boe basis, G&A expenses, excluding cash and non-cash incentive compensation, were $2.92 and $1.80 for the three months ended June 30, 2017 and 2016 , respectively.

G&A expenses totaled $34.8 million and $37.7 million for the six months ended June 30, 2017 and 2016 , respectively. The six months ended June 30, 2016 included $7.1 million in non-cash unit-based incentive compensation expense. The six months ended June 30, 2017 and 2016 included $10.2 million and $8.1 million in cash-based incentive compensation, respectively. G&A expenses, excluding cash and non-cash incentive compensation, were $24.5 million and $22.4 million for the six months ended June 30, 2017 and 2016 , respectively. The increase in G&A, excluding cash and non-cash incentive compensation, during the six months ended June 30, 2017 was primarily due to lower management fee income due to the termination of the Administrative Services Agreement with PCEC, partially offset by lower payroll expenses, professional fees and office rent. On a per Boe basis, G&A expenses, excluding cash and non-cash incentive compensation, were $2.96 and $2.37 for the six months ended June 30, 2017 and 2016 , respectively.

Restructuring costs

During the three months ended June 30, 2016 , we completed workforce reduction plans as part of company-wide reorganization efforts intended to reduce costs, due in part to lower commodity prices. In addition, we executed workforce reductions during the three months ended June 30, 2016 in connection with the termination of the Administrative Services Agreement with PCEC effective as of June 30, 2016. There were no workforce reduction plans during the three months ended June 30, 2017 . The workforce reductions during the three months ended June 30, 2016 were communicated to affected employees on various dates, and all such notifications were completed by June 30, 2016. The plans resulted in a reduction of approximately 12 employees. In connection with the 2016 reduction, during the three months ended June 30, 2016 , we incurred a total cost of approximately $2.4 million , which included severance cash payments, accelerated vesting of LTIP grants for certain individuals and other employee-related termination costs.

During the six months ended June 30, 2016 , we completed workforce reduction plans as part of company-wide reorganization efforts intended to reduce costs, due in part to lower commodity prices and in connection with the termination of the Administrative Services Agreement with PCEC effective as of June 30, 2016. There were no workforce reduction plans during the six months ended June 30, 2017 . The workforce reductions during the six months ended June 30, 2016 were communicated to affected employees on various dates, and all such notifications were completed by June 30, 2016. The plan resulted in a reduction of approximately 69 employees. In connection with the 2016 reduction, during the six months ended June 30, 2016 , we incurred a total cost of approximately $5.2 million , which included severance cash payments, accelerated vesting of LTIP grants for certain individuals and other employee-related termination costs.

Interest expense, net of amounts capitalized

Interest expense totaled $23.0 million and $49.9 million for the three months ended June 30, 2017 and 2016 , respectively. The decrease in interest expense was primarily due to $7.5 million and $11.7 million lower interest expense on our Senior Secured Notes and Senior Unsecured Notes, respectively, during the three months ended June 30, 2017 due to the filing of the Chapter 11 Cases, $15.7 million write-off of debt issuance costs during the three months ended June 30, 2016 related to the reduction of the elected commitment amount under our RBL Credit Agreement, and $1.7 million amortization of debt issuance costs, discounts and premiums during the three months ended June 30, 2016 , partially offset by $9.7 million higher RBL Credit Agreement interest expense in 2017 due to a higher default interest rate resulting from the commencement of the Chapter 11 Cases.

Interest expense, excluding debt amortization and write-offs, totaled $23.0 million and $32.5 million , for the three months ended June 30, 2017 and 2016 , respectively.

Interest expense totaled $45.1 million and $105.9 million for the six months ended June 30, 2017 and 2016 , respectively. The decrease in interest expense was primarily due to $22.5 million and $35.0 million lower interest expense on our Senior Secured Notes and Senior Unsecured Notes, respectively, during the six months ended June 30, 2017 due to the filing of the Chapter 11 Cases, $20.4 million write-off of debt issuance costs during the six months ended June 30, 2016 related to the reduction of the elected commitment amount under our RBL Credit Agreement, and $5.8 million amortization of debt issuance costs, discounts and premiums during the six months ended June 30, 2016 , partially offset by $22.8 million higher RBL Credit Agreement interest expense in 2017 due to a higher default interest rate resulting from the commencement of the Chapter 11 Cases.

Interest expense, excluding debt amortization and write-offs, totaled $45.1 million and $79.8 million for the six months ended June 30, 2017 and 2016 , respectively.

Loss on interest rate swaps

We are subject to interest rate risk associated with loans under the RBL Credit Agreement that bear interest based on floating rates. In order to mitigate our interest rate exposure, as of March 31, 2016, we had interest rate swaps, indexed to 1-month LIBOR, to fix a portion of floating LIBOR-based debt under the RBL Credit Agreement 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. The commencement of the Chapter 11 Cases on May 15, 2016 resulted in an event of default under our commodity and interest rate derivative agreements, resulting in a termination right by our counterparties. All of our interest rate derivative transactions were terminated in connection with the commencement of the Chapter 11 Cases. Accordingly, they are no longer accounted for at fair value, and have been recognized as payables at their termination value. We recognized a gain on interest rate swaps of $0.5 million during the three months ended June 30, 2016 and a loss on interest swaps of $1.8 million during the six months ended June 30, 2016 .

Liquidity and Capital Resources

Overview

Historically, we have used cash flow from operations, borrowings available under our revolving credit facility and amounts raised in the debt and equity capital markets to fund our operations, capital expenditures, acquisitions and cash distributions. Since late 2014, we have had limited access to the credit and capital markets as a result of declines and volatility in oil and natural gas prices. Although oil and natural gas prices have increased since we filed the Chapter 11 Petitions, they remain low historically, and the uncertainty resulting from the Chapter 11 Cases, combined with the uncertainty surrounding future commodity prices, has significantly increased the cost of obtaining money in these markets and limited our ability to access these markets currently as a source of funding. Since the filing of the Chapter 11 Petitions, our principal sources of liquidity have been limited to cash on hand, cash flow from operations and borrowings available under the DIP Credit Agreement. As of June 30, 2017 and December 31, 2016 , we had no amounts borrowed at each date and $52.1 million and $37.9 million , respectively, in letters of credit outstanding under the DIP Credit Agreement. As of each of June 30, 2017 and December 31, 2016 , we had $460.0 million of estimated derivative instrument settlements receivable from the termination of all of our outstanding derivative transactions. Each of our counterparties was required to hold any proceeds due to us in a book entry account maintained by it pursuant to and subject to the provisions of the order of the Bankruptcy Court approving the DIP Credit Agreement, with the rights of all of the parties reserved as to the ultimate disposition of the proceeds.

On July 19, 2017, the Bankruptcy Court authorized the release of the Hedge Proceeds, to be applied to the payment of $4.1 million in Hedge Termination Obligations, with the remaining $460.0 million in Hedge Proceeds to be applied as a dollar-for-dollar reduction of outstanding obligations under the RBL Credit Agreement. We reduced the aggregate principal amount outstanding under the RBL Credit Agreement by $452.2 million , and as of August 8, 2017, we had approximately $746.1 million in aggregate principal amount outstanding under the RBL Credit Agreement.

Liquidity and Ability to Continue as a Going Concern

Although we believe our cash on hand, cash flow from operations and borrowings available under the DIP Credit Agreement will be adequate to meet the operating costs of our existing business, there are no assurances that we will have sufficient liquidity to continue to fund our operations or allow us to continue as a going concern until a plan of reorganization is confirmed by the Bankruptcy Court and becomes effective, and thereafter. Our long-term liquidity requirements, the adequacy of our capital resources and our ability to continue as a going concern are difficult to predict at this time and ultimately cannot be determined until a plan of reorganization has been confirmed, if at all, by the Bankruptcy Court. In addition, we have incurred and continue to incur significant professional fees and costs in connection with the administration of the Chapter 11 Cases, including the fees and expenses of the professionals retained by two statutory committees appointed in the Chapter 11 Cases. We are making adequate protection payments with respect to the RBL Credit Agreement, consisting of the payment of interest (at the default rate) and the payment of all reasonable fees and expenses of professionals retained by our lenders, as provided for in the RBL Credit Agreement. We are also making adequate protection payments with respect to the Senior Secured Notes in the form of the payment of all reasonable fees and expenses of professionals retained by the holders of the Senior Secured Notes. We anticipate that we will continue to incur significant professional fees and costs during the pendency of the Chapter 11 Cases.

Given the uncertainty surrounding the Chapter 11 Cases, there is substantial doubt about our ability to continue as a going concern. The accompanying consolidated financial statements do not purport to reflect or provide for the consequences of the Chapter 11 Cases. In particular, the consolidated financial statements do not purport to show (i) as to assets, their realizable value on a liquidation basis or their fair value or their availability to satisfy liabilities; (ii) as to certain pre-petition liabilities, the amounts that may be allowed for claims or contingencies, or the status and priority thereof; (iii) as to unitholders' equity accounts, the effect of any changes that may be made in our capitalization; or (iv) as to operations, the effect of any changes that may be made to our business. While operating as debtors in possession under chapter 11 of the Bankruptcy Code, the Debtors may sell or otherwise dispose of or liquidate assets or settle liabilities in amounts other than those reflected in our consolidated financial statements, subject to the approval of the Bankruptcy Court or otherwise as permitted in the ordinary course of business. Further, a plan of reorganization could materially change the amounts and classifications in our historical consolidated financial statements.

In addition to the uncertainty resulting from the Chapter 11 Cases, oil and natural gas prices continue to remain low historically. During the six months ended June 30, 2014, 2015, 2016 and 2017, the WTI posted price averaged approximately $101 per Bbl, $53 per Bbl, $40 per Bbl and $50 per Bbl, respectively. During the six months ended June 30, 2014, 2015, 2016 and 2017, the Henry Hub posted price averaged approximately $4.89 per MMBtu, $2.82 per MMBtu, $2.07 per MMBtu and $3.05 per MMBtu. Our revenue, profitability and cash flow are highly sensitive to movements in oil and natural gas prices. Sustained depressed prices of oil and natural gas will materially adversely affect our assets, development plans, results of operations and financial condition. The filing of the Chapter 11 Petitions triggered an event of default under each of the agreements governing our derivative transactions. As a result, our counterparties were permitted to terminate, and did terminate, all outstanding derivative transactions. As of June 30, 2017 , none of our estimated future production was covered by commodity derivatives, and we may not be able to enter into commodity derivatives covering our estimated future production on favorable terms or at all. As a result, we have significant exposure to fluctuations in oil and natural gas prices and our inability to hedge the risk of low commodity prices in the future, on favorable terms or at all, could have a material adverse impact on our business, results of operations and financial condition.

If our future sources of liquidity are insufficient, we could face substantial liquidity constraints and be unable to continue as a going concern and would likely be required to implement further cost reductions, significantly reduce, delay or eliminate capital expenditures, seek other financing alternatives or seek the sale of some or all of our assets. If we (i) continue to limit, defer or eliminate future capital expenditure plans, (ii) are unsuccessful in developing reserves and adding production through our capital program or (iii) implement cost-cutting efforts that are too overreaching, the value of our oil and natural gas properties and our financial condition and results of operations could be adversely affected. We have been managing our operating activities and liquidity carefully in light of the uncertainty regarding future oil and natural gas prices and the Chapter 11 Cases. To fund capital expenditures, we will be required to use cash on hand, cash generated from operations or borrowings under the DIP Credit Agreement, or some combination thereof. We expect our full year 2017 capital spending program to be approximately $110 million . 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 Ark-La-Tex, the Permian Basin and Mid-Continent that are designed to increase or add to production or reserves.

DIP Credit Agreement

In connection with the Chapter 11 Cases, BOLP entered into the DIP Credit Agreement, as borrower, with the DIP Lenders and Wells Fargo, National Association, as administrative agent. The other Debtors have guaranteed all obligations under the DIP Credit Agreement. Pursuant to the terms of the DIP Credit Agreement, the DIP Lenders made available a revolving credit facility in an aggregate principal amount of $150 million, which includes a letter of credit facility available for the issuance of letters of credit in an aggregate principal amount not to exceed a sublimit of $100 million, and a swingline facility in an aggregate principal amount not to exceed a sublimit of $5 million, in each case, to mature on the earlier to occur of (A) the effective date of a plan of reorganization in the Chapter 11 Cases or (B) the stated maturity of the DIP Credit Agreement of June 30, 2017. In addition, the maturity date of the DIP Credit Agreement may be accelerated upon the occurrence of certain events as set forth therein. The DIP Credit Agreement also permits the cash collateralization of letters of credit issued for ordinary course of business purposes by Wells Fargo Bank, National Association. The DIP Credit Agreement does not permit us to make distributions on our Common Units.

On May 10, 2017, the Bankruptcy Court entered an order approving the Third Amendment to the DIP Credit Agreement, effective as of May 11, 2017, by and among the DIP Borrower, the Partnership, the DIP Lenders and the Administrative Agent (the “Third Amendment”). The Third Amendment, among other things, extended the DIP Credit Agreement’s scheduled maturity date to September 30, 2017 and provided for the payment of certain fees to the Administrative Agent and the DIP Lenders.

The proceeds of the DIP Credit Agreement may be used: (i) to pay the costs and expenses of administering the Chapter 11 Cases, (ii) to fund our working capital needs, capital improvements, and other general corporate purposes, in each case, in accordance with an agreed budget and (iii) to provide adequate protection to existing secured creditors as described above.

At June 30, 2017 and December 31, 2016 , we had no borrowings outstanding and $52.1 million and $37.9 million in letters of credit outstanding, respectively, under the DIP Credit Agreement.

Acceleration of Debt Obligations

The commencement of the Chapter 11 Cases resulted in the acceleration of the Debtors’ obligations under the RBL Credit Agreement, the Senior Unsecured Notes and the Senior Secured Notes. Any efforts to enforce such obligations are automatically stayed as a result of the filing of the Chapter 11 Petitions and the holders’ rights of enforcement in respect of these obligations are subject to the applicable provisions of the Bankruptcy Code.

RBL Credit Agreement

BOLP, as borrower, and we and our wholly-owned subsidiaries, as guarantors, are party to 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 RBL Credit Agreement on November 19, 2014. The RBL Credit Agreement 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. At each of June 30, 2017 , and December 31, 2016 , we had $1.2 billion in indebtedness outstanding under the RBL Credit Agreement.

As of the Chapter 11 Filing Date, we had $1.2 billion in aggregate principal amount outstanding under the RBL Credit Agreement, the borrowing base was $1.8 billion and the aggregate commitment from lenders was $1.4 billion. The RBL Credit Agreement is secured by a first priority security interest in and lien on substantially all of the Debtors' assets, including the proceeds thereof and after-acquired property. We determined at the Chapter 11 Filing Date that the RBL Credit Agreement was fully collateralized. As a result of the automatic acceleration of our obligations under the RBL Credit Agreement as a consequence of the commencement of the Chapter 11 Cases, we reclassified the entire RBL Credit Agreement balance to current portion of long-term debt on the consolidated balance sheet. As of the Chapter 11 Filing Date, we recognized $15.7 million of interest expense for the full write-off of unamortized debt issuance costs related to the RBL Credit Agreement.

We are required to make adequate protection payments with respect to the RBL Credit Agreement, consisting of the payment of interest (at the default rate) and the payment of all reasonable fees and expenses of professionals retained by our lenders, as provided for in the RBL Credit Agreement. We are recognizing the default interest accrued on the RBL Credit Agreement as interest expense, net of capitalized interest on the consolidated statements of operations, and we are recognizing the adequate protection payments as accrued interest payable on the consolidated balance sheets, rather than in liabilities subject to compromise. At June 30, 2017 , the default interest rate on the RBL Credit Agreement was 7.5% .

On July 19, 2017, the Bankruptcy Court authorized the release of the Hedge Proceeds, to be applied to the payment of the Hedge Termination Obligations, with the remaining Hedge Proceeds to be applied as a dollar-for-dollar reduction of outstanding obligations under the RBL Credit Agreement. As of August 8, 2017, we had approximately $ 746.1 million in aggregate principal amount outstanding under the RBL Credit Agreement. See Note 15 to the consolidated financial statements in this report for more information.

Senior Unsecured Notes

As of June 30, 2017 and December 31, 2016 , we had $850 million in aggregate principal amount of 2022 Senior Notes outstanding and $305 million in aggregate principal amount of 2020 Senior Notes outstanding. Interest on the Senior Unsecured Notes was payable twice a year in April and October. As a consequence of the commencement of the Chapter 11 Cases on May 15, 2016, we did not pay $33.5 million in interest due with respect to our 2022 Senior Notes and $13.2 million in interest due with respect to our 2020 Senior Notes, each of which were due on April 15, 2016. As of June 30, 2017 and December 31, 2016 , the Senior Unsecured Notes were reflected as liabilities subject to compromise on the consolidated balance sheet, with the carrying values equal to the face values.

Senior Secured Notes

As of June 30, 2017 and December 31, 2016 , we had $650 million in aggregate principal amount of Senior Secured Notes outstanding. Interest on the Senior Secured Notes was payable quarterly in March, June, September and December. As a consequence of the commencement of the Chapter 11 Cases on May 15, 2016, no interest has been paid to the holders of the Senior Secured Notes subsequent to the Chapter 11 filing date. As of June 30, 2017 and December 31, 2016 , the Senior Secured Notes were reflected as liabilities subject to compromise on the consolidated balance sheet, with the carrying value equal to the face value.

Common Units

As of June 30, 2017 and December 31, 2016 , we had 213.8 million Common Units outstanding. The Board suspended distributions on Common Units effective with the third monthly payment attributable to the third quarter of 2015.

Preferred Units

As of June 30, 2017 and December 31, 2016 , we had 8.0 million Series A Preferred Units outstanding. 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.

As of June 30, 2017 and December 31, 2016 , we had 49.6 million Series B Preferred Units outstanding. The Series B Preferred Units rank senior to our Common Units and on parity with the Series A Preferred Units with respect to the payment of distributions.

On April 14, 2016, we elected to suspend the declaration of any further distributions on our Series A Preferred Units and Series B Preferred Units. We have not been accruing distributions on the Series A Preferred Units and Series B Preferred Units since the Chapter 11 Filing Date.

During the three months and six months ended June 30, 2016 , we recognized \$2.0 million and \$6.1 million , respectively, of accrued distributions on the Series A Preferred Units, which were included in distributions to Series A preferred unitholders on the consolidated statements of operations.

Distributions on the Series B Preferred Units are cumulative from the date of original issue and are payable monthly in arrears on the 15 th day of each month of each year, when, as and if declared by our Board out of legally available funds for such purpose. During three months and six months ended June 30, 2016 , we recognized \$3.7 million and \$11.1 million , respectively of accrued distributions on the Series B Preferred Units, which were included in non-cash distributions to Series B preferred unitholders on the consolidated statements of operations.

Cash Flows

Operating activities. Our cash used in operating activities for the six months ended June 30, 2017 was \$13.1 million compared to cash provided by operating activities of \$161.0 million for the six months ended June 30, 2016 . The decrease in cash flows from operating activities was primarily due to \$172.2 million lower commodity derivative settlement receipts due to the termination of our derivative transactions in connection with the filing of the Chapter 11 Petitions, \$22.4 million higher cash interest expense, a 12% decrease in sales volume primarily due to lower production from our Mid-Continent, Ark-La-Tex, Rockies and Permian Basin properties, which reduced sales revenue by approximately \$28.1 million , a \$14.7 million increase in operating costs primarily at our Ark-La-Tex, Southeast and Midwest properties and \$4.2 million higher cash G&A expenses. These decreases were partially offset by higher commodity prices, which increased sales revenue by approximately \$79.4 million .

Investing activities. Net cash flows used in investing activities during the six months ended June 30, 2017 and 2016 were \$45.9 million and \$41.0 million , respectively. During the six months ended June 30, 2017 , we spent \$44.3 million on capital expenditures, primarily for oil and gas activities and \$2.0 million on property acquisitions, primarily for unproved properties, partially offset by \$0.4 million in net proceeds from sale of assets. During the six months ended June 30, 2016 , we spent \$46.3 million on capital expenditures, consisting of approximately \$41.5 million primarily for drilling and completion activities, and approximately \$4.8 million for IT and other capital expenditures, \$6.9 million on purchases of available-for-sale securities, and \$6.0 million on property acquisitions, primarily for CO2 producing properties, partially offset by \$11.8 million in net proceeds from sale of assets and \$6.3 million in proceeds from the sale of available-for-sale securities.

Financing activities. Net cash flows used in financing activities for the six months ended June 30, 2017 and 2016 were \$1.7 million and \$40.0 million , respectively. During the six months ended June 30, 2017 , borrowed \$3.0 million and repaid \$3.0 million under the DIP Credit Agreement, and we paid \$1.7 million in debt issuance costs related to the DIP Credit Agreement. During the six months ended June 30, 2016 , we made cash distributions of \$5.5 million on Series A Preferred Units, borrowed \$37.3 million and repaid \$69.0 million under the RBL Credit Agreement, and we paid \$2.7 million in debt issuance costs related to the DIP Credit Agreement.

Contractual Obligations and Commitments

Financial instruments that potentially subject us to concentrations of credit risk consist principally of accounts receivable, including hedge settlements receivable. Our hedge settlements receivable expose us to credit risk from counterparties. As of June 30, 2017 , our hedge settlements receivable were due from Bank of Montreal, Barclays Bank PLC, BNP Paribas, Canadian Imperial Bank of Commerce, Citibank, N.A, Comerica Bank, Credit Suisse Energy LLC, Credit Suisse International, ING Capital Markets LLC, Fifth Third Bank, JP Morgan Chase Bank N.A., Merrill Lynch Commodities, Inc., Morgan Stanley Capital Group Inc., PNC Bank, N.A, Royal Bank of Canada, The Bank of Nova Scotia, The Toronto-Dominion Bank, MUFG Union Bank N.A. and Wells Fargo Bank, N.A. All of our counterparties were lenders, or affiliates of lenders, under the RBL Credit Agreement. The RBL 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. 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 has been managed by diversifying our derivatives portfolio. As of June 30, 2017 , each of these financial institutions and/or their parent company had an investment grade credit rating from Moody's Investors Service and Standard & Poor's. As of June 30, 2017 , our largest derivative instruments receivable were with Barclays Bank PLC , Credit Suisse Energy LLC , Morgan Stanley Capital Group Inc. , and Wells Fargo Bank, N.A. , which accounted for approximately 14% , 12% , 11% and 11% of our total derivative instruments receivable, respectively.

On July 19, 2017, the Bankruptcy Court authorized the release of the Hedge Proceeds, to be applied to the payment of the Hedge Termination Obligations, with the remaining Hedge Proceeds to be applied as a dollar-for-dollar reduction of outstanding obligations under the RBL Credit Agreement. As of August 8, 2017, we had approximately $ 746.1 million in aggregate principal amount outstanding under the RBL Credit Agreement. See Note 15 to the consolidated financial statements in this report for more information.

Off-Balance Sheet Arrangements

We did not have any off-balance sheet arrangements as of June 30, 2017 and December 31, 2016 .

New Accounting Standards

See Note 1 to the consolidated financial statements in this report for a discussion of new accounting standards applicable to us.

Item 3. ***Quantitative and Qualitative Disclosures About Market Risk***

The following should be read in conjunction with "Quantitative and Qualitative Disclosures About Market Risk" included under Part II—Item 7A in our 2016 Annual Report. Also, see Note 4 to the consolidated financial statements in this report for additional discussion related to our financial instruments. In the past, we have entered into derivative instruments to manage our exposure to commodity price and interest rate volatility, and to assist with stabilizing cash flows. As a result of certain events of default under our derivative contracts, all of our derivative transactions have been terminated.

Item 4. ***Controls and Procedures***

Controls and Procedures

As required by Rule 13a-15(b) of the Securities Exchange Act of 1934, as amended (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 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 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange 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 June 30, 2017 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2017 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***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. For information relating to the Chapter 11 Cases, see Part I—Item 2 "—Management's Discussion and Analysis of Financial Condition and Results of Operations—Chapter 11 Cases" and Note 2 to the consolidated financial statements in this report.

Item 1A. ***Risk Factors***

There have been no material changes to the Risk Factors disclosed in Part I—Item 1A "—Risk Factors" of our 2016 Annual Report.

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

None.

Item 3. ***Defaults Upon Senior Securities***

For information regarding the Chapter 11 Cases, see Note 2 to the consolidated financial statements in this report.

Item 4. ***Mine Safety Disclosures***

Not applicable.

Item 5. ***Other Information***

None.

Item 6. ***Exhibits***

NUMBER	DOCUMENT
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 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 filed on April 14, 2015).
3.4	First Amendment to Third Amended and Restated Limited Partnership Agreement of Breitburn Energy Partners LP, effective as of May 13, 2016 (incorporated herein by reference to Exhibit 3.4 to the Annual Report on Form 10-K filed on March 8, 2017).
3.5	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 filed on April 9, 2010).
3.6	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 filed on January 6, 2011).
3.7	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 filed on July 2, 2014).
3.8	Amendment No. 3 to the Fourth Amended and Restated Limited Liability Company Agreement of Breitburn GP LLC, effective as of May 13, 2016 (incorporated by reference to Exhibit 3.8 to the Annual Report on Form 10-K filed on March 8, 2017).
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 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 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 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 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 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).
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.
101*	Interactive Data Files.
*	Filed herewith.
**	Furnished herewith.
†	Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements 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: August 9, 2017

By: /s/ Halbert S. Washburn
Halbert S. Washburn
Chief Executive Officer

Dated: August 9, 2017

By: /s/ James G. Jackson
James G. Jackson
Chief Financial Officer

Exhibit 31.1

RULE 13a-14(a)/15d-14(a) CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Halbert S. Washburn, certify that:

1. I have reviewed this report on Form 10-Q of Breitburn Energy Partners LP;

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

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

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

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

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

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

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

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

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

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

/s/ Halbert S. Washburn

Halbert S. Washburn

Chief Executive Officer of Breitburn GP LLC

Date: August 9, 2017

Exhibit 31.2

RULE 13a-14(a)/15d-14(a) CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, James G. Jackson, certify that:

1. I have reviewed this report on Form 10-Q of Breitburn Energy Partners LP;

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

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

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

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

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

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

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

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

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

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

/s/ James G. Jackson

James G. Jackson

Chief Financial Officer of Breitburn GP LLC

Date: August 9, 2017

Exhibit 32.1

CERTIFICATION PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002 (18 U.S.C. SECTION 1350)

In connection with the Quarterly Report of Breitburn Energy Partners LP (the "Partnership") on Form 10-Q for the period ended June 30, 2017 , as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Halbert S. Washburn, Chief Executive Officer of Breitburn GP LLC, the general partner of the Partnership, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Halbert S. Washburn

Halbert S. Washburn
Chief Executive Officer of Breitburn GP LLC

Date: August 9, 2017

Exhibit 32.2

CERTIFICATION PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002 (18 U.S.C. SECTION 1350)

In connection with the Quarterly Report of Breitburn Energy Partners LP (the “Partnership”) on Form 10-Q for the period ended June 30, 2017 , as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, James G. Jackson, Chief Financial Officer of Breitburn GP LLC, the general partner of the Partnership, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ James G. Jackson

James G. Jackson

Chief Financial Officer of Breitburn GP LLC

Date: August 9, 2017