Blueknight Energy Partners, L.P.
Form 10-Q
May 10, 2018

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

FORM 10-Q

x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended March 31, 2018

OR

o 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 001-33503

BLUEKNIGHT ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-8536826 (IRS Employer Identification No.)

201 NW 10th, Suite 200
Oklahoma City, Oklahoma 73103
(Address of principal executive offices, zip code)

Registrant's telephone number, including area code: (405) 278-6400

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

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

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 x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth 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. (Check one):

Large accelerated filer o Accelerated filer x

Non-accelerated filer o (Do not check if a smaller reporting company) Smaller reporting company o
Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

As of May 3, 2018, there were 35,125,202 Series A Preferred Units and 40,321,442 common units outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Unaudited Condensed Consolidated Financial Statements

BLUEKNIGHT ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands, except unit data)

	As of December 31, 2017	As of March 31, 2018 (unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$2,469	$2,081
Accounts receivable, net of allowance for doubtful accounts of $28 and $36 at December 31, 2017 and March 31, 2018, respectively	7,589	10,392
Receivables from related parties, net of allowance for doubtful accounts of $0 at both dates	3,070	2,110
Prepaid insurance	2,009	1,985
Other current assets	8,438	8,503
Total current assets	23,575	25,071
Property, plant and equipment, net of accumulated depreciation of $316,591 and $319,220 at December 31, 2017 and March 31, 2018, respectively	296,069	304,416
Assets held for sale, net of accumulated depreciation and amortization of $3,736 at March 31, 2018	—	1,536
Goodwill	3,870	6,728
Debt issuance costs, net	4,442	4,186
Intangibles and other assets, net	12,913	19,654
Total assets	$340,869	$361,591
LIABILITIES AND PARTNERS’ CAPITAL		
Current liabilities:		
Accounts payable	$4,439	$4,699
Accounts payable to related parties	2,268	3,266
Accrued interest payable	694	718
Accrued property taxes payable	2,432	2,352
Unearned revenue	2,393	3,028
Unearned revenue with related parties	551	4,312
Accrued payroll	6,119	2,796
Other current liabilities	4,747	4,335
Total current liabilities	23,643	25,506
Long-term unearned revenue with related parties	1,052	996
Other long-term liabilities	3,673	3,642
Long-term interest rate swap liabilities	225	—
Long-term debt	307,592	334,592
Commitments and contingencies (Note 15)		
Partners’ capital:		
Common unitholders (40,158,342 and 40,321,442 units issued and outstanding at December 31, 2017 and March 31, 2018, respectively)	454,358	446,471
Preferred Units (35,125,202 units issued and outstanding at both dates)	253,923	253,923
	(703,597)	(703,539)

General partner interest (1.6% interest with 1,225,409 general partner units outstanding at both dates)		
Total partners’ capital	4,684	(3,145)
Total liabilities and partners’ capital	$340,869	$361,591

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

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BLUEKNIGHT ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit data)

	Three Months ended March 31,	
	2017	2018
	(unaudited)	
Service revenue:		
Third-party revenue	$28,663	$17,318
Related-party revenue	13,642	6,321
Lease revenue:		
Third-party revenue	—	9,804
Related-party revenue	—	7,703
Product sales revenue:		
Third-party revenue	4,035	3,514
Total revenue	46,340	44,660
Costs and expenses:		
Operating expense	31,906	31,135
Cost of product sales	3,139	2,637
General and administrative expense	4,585	4,221
Asset impairment expense	28	616
Total costs and expenses	39,658	38,609
Loss on sale of assets	(125)	(236)
Operating income	6,557	5,815
Other income (expenses):		
Equity earnings in unconsolidated affiliate	61	—
Gain on sale of unconsolidated affiliate	—	2,225
Interest expense (net of capitalized interest of $2 and $28, respectively)	(3,030)	(3,569)
Income before income taxes	3,588	4,471
Provision for income taxes	46	29
Net income	$3,542	$4,442
Allocation of net income for calculation of earnings per unit:		
General partner interest in net income	$209	$231
Preferred interest in net income	$6,279	$6,278
Net loss available to limited partners	$(2,946)	$(2,067)
Basic and diluted net loss per common unit	$(0.08)	$(0.05)
Weighted average common units outstanding - basic and diluted	38,146	40,289

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

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BLUEKNIGHT ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' CAPITAL (DEFICIT)
(in thousands)

	Common Unitholders	Series A Preferred Unitholders	General Partner Interest	Total Partners' Capital (Deficit)
	(unaudited)			
Balance, December 31, 2017	$454,358	$253,923	$(703,597)	$4,684
Net income (loss)	(2,065)	6,279	228	4,442
Equity-based incentive compensation	33	—	8	41
Distributions	(5,947)	(6,279)	(361)	(12,587)
Capital contributions	—	—	183	183
Proceeds from sale of 21,246 common units pursuant to the Employee Unit Purchase Plan	92	—	—	92
Balance, March 31, 2018	$446,471	$253,923	$(703,539)	$(3,145)

The accompanying notes are an integral part of this unaudited condensed consolidated financial statement.

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BLUEKNIGHT ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Three Months ended March 31,	
	2017	2018
	(unaudited)	
Cash flows from operating activities:		
Net income	$3,542	$4,442
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for uncollectible receivables from third parties	(8)	8
Depreciation and amortization	8,066	7,367
Amortization of debt issuance costs	342	256
Unrealized gain related to interest rate swaps	(752)	(354)
Intangible asset impairment charge	—	189
Fixed asset impairment charge	28	427
Loss on sale of assets	125	236
Gain on sale of unconsolidated affiliate	—	(2,225)
Equity-based incentive compensation	(125)	41
Equity earnings in unconsolidated affiliate	(61)	—
Changes in assets and liabilities:		
Increase in accounts receivable	(3,806)	(2,811)
Decrease in receivables from related parties	303	960
Decrease in prepaid insurance	441	744
Increase in other current assets	(610)	(345)
Decrease in other assets	3	41
Decrease in accounts payable	(86)	(154)
Increase in payables to related parties	227	625
Increase (decrease) in accrued interest payable	(117)	24
Decrease in accrued property taxes	(695)	(80)
Increase in unearned revenue	794	637
Increase in unearned revenue from related parties	3,753	3,655
Decrease in accrued payroll	(3,372)	(3,323)
Decrease in other accrued liabilities	(443)	(419)
Net cash provided by operating activities	7,549	9,941
Cash flows from investing activities:		
Acquisitions	—	(21,959)
Capital expenditures	(4,052)	(4,563)
Proceeds from sale of assets	2,850	26
Proceeds from sale of unconsolidated affiliate	—	2,225
Net cash used in investing activities	(1,202)	(24,271)
Cash flows from financing activities:		
Payment on insurance premium financing agreement	(773)	(746)
Debt issuance costs	(7)	—
Borrowings under credit agreement	25,000	54,000
Payments under credit agreement	(19,000)	(27,000)
Proceeds from equity issuance	84	92
Capital contributions	104	183

Distributions	(12,252)	(12,587)
Net cash provided by (used in) financing activities	(6,844)	13,942
Net decrease in cash and cash equivalents	(497)	(388)
Cash and cash equivalents at beginning of period	3,304	2,469
Cash and cash equivalents at end of period	$2,807	$2,081
Supplemental disclosure of non-cash financing and investing cash flow information:		
Non-cash changes in property, plant and equipment	$1,790	$1,251
Increase in accrued liabilities related to insurance premium financing agreement	$750	$720

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

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BLUEKNIGHT ENERGY PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND NATURE OF BUSINESS

Blueknight Energy Partners, L.P. and subsidiaries (collectively, the "Partnership") is a publicly traded master limited partnership with operations in 27 states. The Partnership provides integrated terminalling, gathering, transportation and marketing services for companies engaged in the production, distribution and marketing of crude oil and asphalt products. The Partnership manages its operations through four operating segments: (i) asphalt terminalling services, (ii) crude oil terminalling services, (iii) crude oil pipeline services and (iv) crude oil trucking and producer field services. The Partnership's common units and preferred units, which represent limited partnership interests in the Partnership, are listed on the NASDAQ Global Market under the symbols "BKEP" and "BKEPP," respectively. The Partnership was formed in February 2007 as a Delaware master limited partnership initially to own, operate and develop a diversified portfolio of complementary midstream energy assets.

2. BASIS OF CONSOLIDATION AND PRESENTATION

The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The condensed consolidated statements of operations for the three months ended March 31, 2017 and 2018, the condensed consolidated statement of changes in partners' capital for the three months ended March 31, 2018, the condensed consolidated statements of cash flows for the three months ended March 31, 2017 and 2018, and the condensed consolidated balance sheet as of March 31, 2018, are unaudited. In the opinion of management, the unaudited condensed consolidated financial statements have been prepared on the same basis as the audited financial statements and include all adjustments necessary to state fairly the financial position and results of operations for the respective interim periods. All adjustments are of a recurring nature unless otherwise disclosed herein. The 2017 year-end condensed consolidated balance sheet data was derived from audited financial statements but does not include all disclosures required by GAAP. These unaudited condensed consolidated financial statements and notes should be read in conjunction with the consolidated financial statements and notes thereto included in the Partnership's annual report on Form 10-K for the year ended December 31, 2017, filed with the Securities and Exchange Commission (the "SEC") on March 8, 2018 (the "2017 Form 10-K"). Interim financial results are not necessarily indicative of the results to be expected for an annual period. The Partnership's significant accounting policies are consistent with those disclosed in Note 3 of the Notes to Consolidated Financial Statements in its 2017 Form 10-K.

The Partnership's investment in Advantage Pipeline, L.L.C. ("Advantage Pipeline"), over which the Partnership had significant influence but not control, was accounted for by the equity method. The Partnership did not consolidate any part of the assets or liabilities of its equity investee. The Partnership's share of net income or loss is reflected as one line item on the Partnership's unaudited condensed consolidated statements of operations entitled "Equity earnings in unconsolidated affiliate" and increased or decreased, as applicable, the carrying value of the Partnership's "Investment in unconsolidated affiliate" on the unaudited condensed consolidated balance sheets. Distributions to the Partnership reduced the carrying value of its investment and, to the extent received, were reflected in the Partnership's unaudited condensed consolidated statements of cash flows in the line item "Distributions from unconsolidated affiliate." Contributions increased the carrying value of the Partnership's investment and were reflected in the Partnership's unaudited condensed consolidated statements of cash flows in investing activities. On April 3, 2017, the Partnership sold its investment in Advantage Pipeline. See Note 5 for additional information.

3. REVENUE

Revenue from Contracts with Customers

On January 1, 2018, the Partnership adopted the new accounting standard ASC 606 - Revenue from Contracts with Customers and all related amendments ("new revenue standard") using the modified retrospective method, and as a result applied the new guidance only to contracts that are not completed at the adoption date. Results for reporting periods beginning on January 1, 2018, are presented under the new revenue standard, while prior period amounts are not adjusted and continue to be reported in accordance with the Partnership's historic accounting under ASC 605 - Revenue Recognition.

The majority of the Partnership's services revenue continues to be recognized as services are performed. Under the new revenue standard, the timing of revenue recognition on variable throughput fees will change, within a single reporting year, compared to the previous recognition. The effect will be straight-line recognition of unconstrained estimated annual throughput volumes over each contract year. See further discussion on variable throughput fees below. In addition, as a result of the adoption of the new revenue standard, revenue from leases is required to be presented separately from revenue from customers. As the Partnership applied the modified retrospective method, prior periods have not been reclassified.

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Upon adoption of the new revenue standard, there was no cumulative adjustment to the balance sheet at January 1, 2018. Adoption of the new revenue standard resulted in recognition of an additional $0.1 million of “Service revenue - Third-party revenue” in the unaudited condensed consolidated statement of operations for the three months ended March 31, 2018, and “Accounts receivable” on the unaudited condensed consolidated balance sheet as of March 31, 2018, over what would have been recorded under ASC 605. While some revenue under storage, throughput and handling contracts in the asphalt terminalling segment will shift between quarters within a fiscal year, the impact of adoption of the new revenue standard is not expected to be material to net income on an ongoing basis because the analysis of contracts under the new revenue standard supports the recognition of revenue as services are performed, which is consistent with the previous revenue recognition model.

There are two types of contracts in the asphalt terminalling segment: (i) operating lease contracts, under which customers operate the facilities, and (ii) storage, throughput and handling contracts, under which the Partnership operates the facilities. The operating lease contracts are accounted for in accordance with ASC 840 - Leases. The storage, throughput and handling contracts contain both lease revenue and non-lease service revenue. In accordance with ASC 840 and 606, fixed consideration is allocated to the lease and service components based on their relative stand-alone selling price. The stand-alone selling price of the lease component is calculated using the average internal rate of return under the operating lease agreements. The stand-alone selling price of the service component is calculated by applying an appropriate margin to the expected costs to operate the facility. The service component contains a single performance obligation that consists of a stand-ready obligation to perform activities as directed by the customer. Revenue is recognized on a straight-line basis over time as the customer receives and consumes benefits. Fixed consideration, consisting of the monthly storage and handling fees, is billed a month prior to the performance of services and is due by the first day of the month of service. Payments received in advance of the month of service are recorded as unearned revenue (contract liability) until the service is performed.

Asphalt storage, throughput and handling contracts also contain variable consideration in the form of reimbursements of utility, fuel and power expenses and throughput fees. Utility, fuel and power reimbursements are allocated entirely to the service component of the contracts. Utility, fuel and power reimbursements relate directly to the distinct monthly service that makes up the overall performance obligation and revenue is recognized in the period in which the service takes place. Variable consideration related to reimbursements of utility, fuel and power expenses is billed in the month subsequent to the period of service, and payment is due within 30 days of billing. Throughput fees are allocated to both the lease and service component of the contracts using the allocation percentages from contract inception. Total throughput fees are estimated at contract inception and updated at the beginning of each reporting period based on historical trends, current year throughput activities at the facilities, and analysis with customers regarding expectations for the current year. This consideration can be constrained when there is a lack of historical data or other uncertainties exist regarding expected throughput volumes. The service component of throughput fees is recognized on a straight-line basis over time as the customer receives and consumes benefits. In accordance with ASC 840, the lease component of variable throughput fees is recognized in the period when the changes in facts and circumstances on which the variable payment is based occur. Fees related to actual throughput are billed in the month subsequent to the period of movement, which can result in the recognition of un-billed accounts receivable (contract assets) when there is a variance in the straight-line revenue recognition and actual throughput fees billed. Payment on variable throughput consideration is due within 30 days of billing. Changes in estimated throughput fees affect the total transaction price and will be recorded as an adjustment to revenue in the period in which the change is identified. There was no adjustment related to changes in estimated throughput fees for the three months ended March 31, 2018.

Certain asphalt storage, throughput and handling contracts contain provisions for reimbursement of specified major maintenance costs above a specified threshold over the life of the contract. Reimbursements of specified major maintenance costs are allocated to both the lease and service component of the contracts using the allocation percentages from contract inception. Reimbursements of specified major maintenance costs are reviewed and paid quarterly, which may result in overpayments that must be paid back to the customer in future years. As such, the service component of this consideration is constrained and recorded in unearned revenue (contract liability) until facts and circumstances indicate it is probable that the minimum threshold will be met. In the event the minimum threshold is not met, the Partnership will return the reimbursement to the customer.

As of March 31, 2018, the Partnership has performance obligations satisfied over time under asphalt storage, throughput and handling contracts that are wholly or partially unsatisfied. The revenue related to these performance obligations will be recognized as follows (in thousands):

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Revenue Related to Future Performance Obligations Due by Period[1]	
Less than 1 year	$35,270
1-3 years	63,229
4-5 years	48,079
More than 5 years	17,181
Total revenue related to future performance obligations	$163,759

(1) Excluded from the table is revenue that is either constrained or related to performance obligations that are wholly unsatisfied as of March 31, 2018.

Crude oil terminalling services contracts can be either short- or long-term written contracts. The contracts contain a single performance obligation that consists of a series of distinct services provided over time. Customers are billed a month prior to the performance of terminalling services and payment is due by the first day of the month of service. Payments received in advance of the month of service are recorded as unearned revenue (contract liability) until the service is performed. These contracts also contain provisions under which customers are invoiced for product throughput in the month following the month in which the service is provided. Payment on product throughput is due within 30 days. The Partnership has elected to use the right-to-invoice expedient on crude oil terminalling services contracts as the right to consideration corresponds directly with the value to the customer of performance completed to date.

There are primarily two types of contracts in the crude oil pipeline segment: (i) monthly transportation contracts and (ii) product sales contracts.

Under crude oil pipeline services monthly transportation contracts, customers submit nominations for transportation monthly and a contract is created upon the Partnership’s acceptance of the nomination under our published tariffs. Crude oil pipeline services contracts have a single performance obligation to perform the transportation service. The transportation service is provided to the customer in the same month in which the customer makes the related nomination. Revenue is recorded in the month of service and invoiced in the following month. Payment is due within 30 days. The Partnership has elected to use the right-to-invoice expedient on crude oil pipeline services contracts as the right to consideration corresponds directly with the value to the customer of performance completed to date.

The Partnership also purchases crude oil and resells to third parties under written product sales contracts. Product sales contracts have a single performance obligation, and revenue is recognized at the point in time that control is transferred to the customer. Control is considered transferred to the customer on the day of the sale. Revenue is recorded in the month of service and invoiced in the following month. Payment is due within 30 days. The Partnership has elected to use the right-to-invoice expedient on product sales contracts as the right to consideration corresponds directly with the value to the customer of performance completed to date.

Services in the crude oil trucking and field services segment are provided under master service agreements with customers that include rate sheets. Contracts are initiated when a customer requests service and both parties are committed upon the Partnership’s acceptance of the customer’s request. Crude oil trucking and field services contracts have a single performance obligation to perform the service, which is completed in a day. Revenue is recorded in the month of service and invoiced in the following month. Payment is due within 30 days. The Partnership has elected to use the right-to-invoice expedient on crude oil trucking and field services revenues as the right to consideration corresponds directly with the value to the customer of performance completed to date.

Disaggregation of Revenue

The following table represents a disaggregation of revenue from contracts with customers for each operating segment by revenue type (in thousands):

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	Three Months ended March 31, 2018				
	Asphalt Terminalling Services	Crude Oil Terminalling Services	Crude Oil Pipeline Services	Crude Oil Trucking and Producer Field Services	Total
Third-party revenue:					
Fixed storage and throughput revenue	$3,549	$ 4,081	$ —	$ —	$7,630
Variable throughput revenue	117	504	—	—	621
Variable reimbursement revenue	1,466	—	—	—	1,466
Crude oil transportation revenue	—	—	2,061	5,540	7,601
Crude oil product sales revenue	—	—	3,508	6	3,514
Related-party revenue:					
Fixed storage and throughput revenue	4,631	—	—	—	4,631
Variable reimbursement revenue	1,690	—	—	—	1,690
Total revenue from contracts with customers	$11,453	$ 4,585	$ 5,569	$ 5,546	$27,153

Contract Balances

The timing of revenue recognition, billings and cash collections result in billed accounts receivable, un-billed accounts receivable (contract assets) and unearned revenue (contract liabilities) on the unaudited condensed consolidated balance sheet as noted in the contract discussions above. Accounts receivable and un-billed accounts receivable are both reflected in the line items “Accounts receivable” and “Receivables from related parties” on the unaudited condensed consolidated balance sheet. Unearned revenue is included in the line items “Unearned revenue,” “Unearned revenue with related parties,” “Long-term unearned revenue with related parties” and “Other long-term liabilities” on the unaudited condensed consolidated balance sheet.

Billed accounts receivable from contracts with customers were $8.5 million and $8.4 million at December 31, 2017, and March 31, 2018, respectively.

Un-billed accounts receivable from contracts with customers were $0.1 million at March 31, 2018. There were no un-billed accounts receivable at December 31, 2017.

The Partnership records unearned revenues when cash payments are received in advance of performance. Unearned revenue related to contracts with customers was $3.7 million and $5.5 million at December 31, 2017, and March 31, 2018, respectively. The increase in the unearned revenue balance for the three months ended March 31, 2018, is driven by $3.3 million in cash payments received in advance of satisfying performance obligations, partially offset by $1.5 million of revenues recognized that were included in the unearned revenue balance at the beginning of the period.

Practical Expedients and Exemptions

The Partnership does not disclose the value of unsatisfied performance obligations for (i) contracts with an original expected length of one year or less and (ii) contracts for which revenue is recognized at the amount to which the Partnership has the right to invoice for services performed. The Partnership is using the right-to-invoice practical expedient on all contracts with customers in its crude oil terminalling services, crude oil pipeline services, and crude oil trucking and producer field services segments.

4. RESTRUCTURING CHARGES

During the fourth quarter of 2015, the Partnership recognized certain restructuring charges in its crude oil trucking and producer field services segment pursuant to an approved plan to exit the trucking market in West Texas.

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Changes in the accrued amounts pertaining to the restructuring charges are summarized as follows (in thousands):

	Three Months ended March 31,	
	2017	2018
Beginning balance	$474	$286
Cash payments	46	49
Ending balance	$428	$237

The remaining accrued amounts relate to lease payments that will be paid over the remaining lease terms, which extend through July 2019.

5. EQUITY METHOD INVESTMENT

On April 3, 2017, Advantage Pipeline was acquired by a joint venture formed by affiliates of Plains All American Pipeline, L.P. and Noble Midstream Partners LP. The Partnership received cash proceeds at closing from the sale of its approximate 30% equity ownership interest in Advantage Pipeline of approximately $25.3 million and recorded a gain on the sale of the investment of $4.2 million. Approximately 10% of the gross sale proceeds were held in escrow, subject to certain post-closing settlement terms and conditions. The Partnership received approximately $1.1 million of the funds held in escrow in August 2017, and approximately $2.2 million for its pro rata portion of the remaining net escrow proceeds in January 2018. The Partnership's proceeds were used to prepay revolving debt (without a commitment reduction). The operating and administrative services agreement to which the Partnership and Advantage Pipeline were parties and under which the Partnership operated the 70-mile, 16-inch Advantage crude oil pipeline, located in the southern Delaware Basin in Texas, was terminated at closing. The Partnership and the Plains/Noble joint venture entered into a short-term transition services agreement under which the Partnership provided certain services through August 1, 2017.

Summarized financial information for Advantage Pipeline is set forth in the tables below for the periods indicated in which the Partnership held the investment in Advantage Pipeline (in thousands):

	As of March 31, 2017
Balance Sheet	
Current assets	$ 1,420
Noncurrent assets	87,811
Total assets	89,231
Current liabilities	1,073
Long-term liabilities	19,067
Member's equity	69,091
Total liabilities and member's equity	$ 89,231

	Three Months ended March 31, 2017
Income Statement	
Operating revenues	$ 3,150

Operating expenses	$ 465
Net income	$ 187

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6. PROPERTY, PLANT AND EQUIPMENT

	Estimated Useful Lives (Years)	December 31, 2017	March 31, 2018
		(dollars in thousands)	
Land	N/A	$24,776	$27,079
Land improvements	10-20	6,787	7,794
Pipelines and facilities	5-30	166,004	165,923
Storage and terminal facilities	10-35	370,056	377,975
Transportation equipment	3-10	3,293	759
Office property and equipment and other	3-20	32,011	32,255
Pipeline linefill and tank bottoms	N/A	3,233	3,619
Construction-in-progress	N/A	6,500	8,232
Property, plant and equipment, gross		612,660	623,636
Accumulated depreciation		(316,591)	(319,220)
Property, plant and equipment, net		$296,069	$304,416

Depreciation expense for the three months ended March 31, 2017 and 2018, was $7.7 million and $7.0 million, respectively.

In March 2018, the Partnership acquired an asphalt terminalling facility in Oklahoma from a third party for approximately $22.0 million, consisting of property, plant and equipment of $11.5 million, intangible assets of $7.6 million and goodwill of $2.9 million.

On April 18, 2017, the Partnership sold its East Texas pipeline system, which was included in assets held for sale as of March 31, 2017. The Partnership received cash proceeds at closing of approximately $4.8 million and recorded a gain of less than $0.1 million. The Partnership used the proceeds received at closing to prepay revolving debt (without a commitment reduction).

7. DEBT

On May 11, 2017, the Partnership entered into an amended and restated credit agreement that consists of a $450.0 million revolving loan facility.

As of May 3, 2018, approximately $328.6 million of revolver borrowings and $1.5 million of letters of credit were outstanding under the credit agreement, leaving the Partnership with approximately $119.9 million available capacity for additional revolver borrowings and letters of credit under the credit agreement, although the Partnership's ability to borrow such funds may be limited by the financial covenants in the credit agreement. The proceeds of loans made under the credit agreement may be used for working capital and other general corporate purposes of the Partnership.

The credit agreement is guaranteed by all of the Partnership's existing subsidiaries. Obligations under the credit agreement are secured by first priority liens on substantially all of the Partnership's assets and those of the guarantors.

The credit agreement includes procedures for additional financial institutions to become revolving lenders, or for any existing lender to increase its revolving commitment thereunder, subject to an aggregate maximum of $600.0 million for all revolving loan commitments under the credit agreement.

The credit agreement will mature on May 11, 2022, and all amounts outstanding under the credit agreement will become due and payable on such date. The credit agreement requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, property or casualty insurance claims and condemnation proceedings, unless the Partnership reinvests such proceeds in accordance with the credit agreement, but these mandatory prepayments will not require any reduction of the lenders' commitments under the credit agreement.

Borrowings under the credit agreement bear interest, at the Partnership's option, at either the reserve-adjusted eurodollar rate (as defined in the credit agreement) plus an applicable margin that ranges from 2.0% to 3.0% or the alternate base rate (the highest of the agent bank's prime rate, the federal funds effective rate plus 0.5%, and the 30-day eurodollar rate plus 1.0%) plus

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an applicable margin that ranges from 1.0% to 2.0%. The Partnership pays a per annum fee on all letters of credit issued under the credit agreement, which fee equals the applicable margin for loans accruing interest based on the eurodollar rate, and the Partnership pays a commitment fee ranging from 0.375% to 0.5% on the unused commitments under the credit agreement. The applicable margins for the Partnership's interest rate, the letter of credit fee and the commitment fee vary quarterly based on the Partnership's consolidated total leverage ratio (as defined in the credit agreement, being generally computed as the ratio of consolidated total debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges).

The credit agreement includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter.

Prior to the date on which the Partnership issues qualified senior notes in an aggregate principal amount (when combined with all other qualified senior notes previously or concurrently issued) that equals or exceeds $200.0 million, the maximum permitted consolidated total leverage ratio is 4.75 to 1.00; provided that the maximum permitted consolidated total leverage ratio will be 5.25 to 1.00 for certain quarters based on the occurrence of a specified acquisition (as defined in the credit agreement, but generally being an acquisition for which the aggregate consideration is $15.0 million or more). The acquisition of the asphalt terminalling facility in March 2018 qualified as a specified acquisition.

From and after the date on which the Partnership issues qualified senior notes in an aggregate principal amount (when combined with all other qualified senior notes previously or concurrently issued) that equals or exceeds $200.0 million, the maximum permitted consolidated total leverage ratio is 5.00 to 1.00; provided that from and after the fiscal quarter ending immediately preceding the fiscal quarter in which a specified acquisition occurs to and including the last day of the second full fiscal quarter following the fiscal quarter in which such acquisition occurred, the maximum permitted consolidated total leverage ratio will be 5.50 to 1.00.

The maximum permitted consolidated senior secured leverage ratio (as defined in the credit agreement, but generally computed as the ratio of consolidated total secured debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 3.50 to 1.00, but this covenant is only tested from and after the date on which the Partnership issues qualified senior notes in an aggregate principal amount (when combined with all other qualified senior notes previously or concurrently issued) that equals or exceeds $200.0 million.

The minimum permitted consolidated interest coverage ratio (as defined in the credit agreement, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest expense) is 2.50 to 1.00.

In addition, the credit agreement contains various covenants that, among other restrictions, limit the Partnership's ability to:

- create, issue, incur or assume indebtedness;
- create, incur or assume liens;
- engage in mergers or acquisitions;
- sell, transfer, assign or convey assets;
- repurchase the Partnership's equity, make distributions to unitholders and make certain other restricted payments;
- make investments;
- modify the terms of certain indebtedness, or prepay certain indebtedness;
- engage in transactions with affiliates;
- enter into certain hedging contracts;
- enter into certain burdensome agreements;
- change the nature of the Partnership's business; and
- make certain amendments to the Partnership's partnership agreement.

At March 31, 2018, the Partnership's consolidated total leverage ratio was 4.90 to 1.00 and the consolidated interest coverage ratio was 4.80 to 1.00. The Partnership was in compliance with all covenants of its credit agreement as of March 31, 2018.

The credit agreement permits the Partnership to make quarterly distributions of available cash (as defined in the Partnership's partnership agreement) to unitholders so long as no default or event of default exists under the credit agreement on a pro forma basis after giving effect to such distribution. The Partnership is currently allowed to make distributions to its unitholders in accordance with this covenant; however, the Partnership will only make distributions to the extent it has sufficient cash from operations after establishment of cash reserves as determined by the Board of Directors (the "Board") of Blueknight Energy Partners G.P., L.L.C (the "general partner") in accordance with the Partnership's cash distribution policy, including the establishment of any reserves for the proper conduct of the Partnership's business. See Note 9 for additional information regarding distributions.

In addition to other customary events of default, the credit agreement includes an event of default if:

(i) the general partner ceases to own 100% of the Partnership's general partner interest or ceases to control the Partnership;
(ii) Ergon, Inc. ("Ergon") ceases to own and control 50% or more of the membership interests of the general partner; or
(iii) during any period of 12 consecutive months, a majority of the members of the Board of the general partner ceases to be composed of individuals:
(A) who were members of the Board on the first day of such period;
(B) whose election or nomination to the Board was approved by individuals referred to in clause (A) above constituting at the time of such election or nomination at least a majority of the Board; or
(C) whose election or nomination to the Board was approved by individuals referred to in clauses (A) and (B) above constituting at the time of such election or nomination at least a majority of the Board, provided that any changes to the composition of individuals serving as members of the Board approved by Ergon will not cause an event of default.

If an event of default relating to bankruptcy or other insolvency events occurs with respect to the general partner or the Partnership, all indebtedness under the credit agreement will immediately become due and payable. If any other event of default exists under the credit agreement, the lenders may accelerate the maturity of the obligations outstanding under the credit agreement and exercise other rights and remedies. In addition, if any event of default exists under the credit agreement, the lenders may commence foreclosure or other actions against the collateral.

If any default occurs under the credit agreement, or if the Partnership is unable to make any of the representations and warranties in the credit agreement, the Partnership will be unable to borrow funds or to have letters of credit issued under the credit agreement.

Upon the execution of the amended and restated credit agreement, the Partnership expensed $0.7 million of debt issuance costs related to the prior revolving loan facility, leaving a remaining balance of $0.9 million ascribed to those lenders with commitments under both the prior and the amended and restated credit agreement. The Partnership capitalized less than $0.1 million of debt issuance costs during the three months ended March 31, 2017. The Partnership capitalized no debt issuance costs during the three months ended March 31, 2018. Debt issuance costs are being amortized over the term of the credit agreement. Interest expense related to debt issuance cost amortization for each of the three months ended March 31, 2017 and 2018, was $0.3 million.

During the three months ended March 31, 2017 and 2018, the weighted average interest rate under the Partnership's credit agreement was 4.11% and 4.96%, respectively, resulting in interest expense of approximately $3.3 million and $3.9 million, respectively.

During each of the three months ended March 31, 2017 and 2018, the Partnership capitalized interest of less than $0.1 million.

The Partnership is exposed to market risk for changes in interest rates related to its credit agreement. Interest rate swap agreements are used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. As of December 31, 2017, and March 31, 2018, the Partnership had interest rate swap agreements with notional amounts totaling $200.0 million to hedge the variability of its LIBOR-based interest payments, with half maturing on June 28, 2018, and the other half maturing on January 28, 2019. During the three months ended March 31, 2017 and 2018, the Partnership recorded swap interest expense of $0.5 million and $0.1 million, respectively. The interest rate swaps do not receive hedge accounting treatment under ASC 815 - Derivatives and Hedging.

The following provides information regarding the Partnership's assets and liabilities related to its interest rate swap agreements as of the periods indicated (in thousands):

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Derivatives Not Designated as Hedging Instruments	Balance Sheet Location	Fair Value of Derivatives	
		December 31, 2017	March 31, 2018
Interest rate swap assets - current	Other current assets	$ 68	$ 197
Interest rate swap liabilities - noncurrent	Long-term interest rate swap liabilities	$ 225	$ —

Changes in the fair value of the interest rate swaps are reflected in the unaudited condensed consolidated statements of operations as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Net Income on Derivatives	Amount of Gain (Loss) Recognized in Net Income on Derivatives Three Months ended March 31,	
		2017	2018
Interest rate swaps	Interest expense, net of capitalized interest	$ 752	$ 354

As discussed above, the Partnership has an obligation to maintain certain financial ratios in accordance with its covenants under the credit agreement. Specifically, the Partnership is required to maintain a total leverage ratio of not greater than 5.25 to 1.00 and an interest coverage ratio of not less than 2.50 to 1.00, each as of the last day of any fiscal quarter. As of March 31, 2018, the Partnership is in compliance with all terms of the credit agreement, with a total leverage ratio of 4.90 to 1.00 and an interest coverage ratio of 4.80 to 1.00. However, with the current weakness in crude oil storage rates, the Partnership's management believes that it is possible that the Partnership may fall out of compliance with these financial covenants as early as the third quarter of 2018. Failure to remain in compliance with the financial covenants could constrain the Partnership's operating flexibility, its ability to fund its business operations and could cause the amounts outstanding under the credit agreement, which was $334.6 million as of March 31, 2018, to become immediately due and payable.

In light of this, the Partnership is considering options to enhance its financial flexibility and fund its operations, including a potential sale of assets, a reduction in the distribution rate that would be paid to the Partnership's common unitholders, and/or the need to amend the financial covenants under the credit agreement. Any amendment of the credit agreement may increase the cost of credit provided under the credit agreement and related expenses, which may adversely impact the Partnership's profitability.

8. NET INCOME PER LIMITED PARTNER UNIT

For purposes of calculating earnings per unit, the excess of distributions over earnings or excess of earnings over distributions for each period are allocated to the Partnership's general partner based on the general partner's ownership interest at the time. The following sets forth the computation of basic and diluted net income per common unit (in thousands, except per unit data):

	Three Months ended March 31,	
	2017	2018

Net income	$3,542	$4,442
General partner interest in net income	209	231
Preferred interest in net income	6,279	6,278
Net loss available to limited partners	$(2,946)	$(2,067)
Basic and diluted weighted average number of units:		
Common units	38,146	40,289
Restricted and phantom units	688	833
Total units	38,834	41,122
Basic and diluted net loss per common unit	$(0.08)	$(0.05)

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9. PARTNERS' CAPITAL AND DISTRIBUTIONS

On December 1, 2017, the Partnership issued 1,898,380 common units to Ergon in a private placement valued at $10.2 million in exchange for an asphalt terminalling facility in Bainbridge, Georgia.

On April 23, 2018, the Board approved a distribution of $0.17875 per outstanding Preferred Unit for the three months ended March 31, 2018. The Partnership will pay this distribution on May 15, 2018, to unitholders of record as of May 4, 2018. The total distribution will be approximately $6.4 million, with approximately $6.3 million and $0.1 million paid to the Partnership's preferred unitholders and general partner, respectively.

In addition, on April 23, 2018, the Board approved a cash distribution of $0.1450 per outstanding common unit for the three months ended March 31, 2018. The Partnership will pay this distribution on May 15, 2018, to unitholders of record on May 4, 2018. The total distribution will be approximately $6.3 million, with approximately $5.8 million and $0.3 million to be paid to the Partnership's common unitholders and general partner, respectively, and $0.2 million to be paid to holders of phantom and restricted units pursuant to awards granted under the Partnership's Long-Term Incentive Plan.

10. RELATED-PARTY TRANSACTIONS

The Partnership leases asphalt facilities to Ergon and provides asphalt terminalling services to Ergon. For the three months ended March 31, 2017 and 2018, the Partnership recognized related-party revenues of $13.3 million and $14.0 million, respectively, for services provided to Ergon. As of December 31, 2017, and March 31, 2018, the Partnership had receivables from Ergon of $3.1 million and $2.1 million, respectively, net of allowance for doubtful accounts. As of December 31, 2017, and March 31, 2018, the Partnership had unearned revenues from Ergon of $1.6 million and $5.3 million, respectively.

The Partnership provided operating and administrative services to Advantage Pipeline. On April 3, 2017, the Partnership sold its investment in Advantage Pipeline. See Note 5 for additional information. For the three months ended March 31, 2017, the Partnership earned revenues of $0.3 million for services provided to Advantage Pipeline.

11. LONG-TERM INCENTIVE PLAN

In July 2007, the general partner adopted the Long-Term Incentive Plan (the "LTIP"), which is administered by the compensation committee of the Board. Effective April 29, 2014, the Partnership's unitholders approved an amendment to the LTIP to increase the number of common units reserved for issuance under the incentive plan to 4,100,000 common units, subject to adjustments for certain events. Although other types of awards are contemplated under the LTIP, currently outstanding awards include "phantom" units, which convey the right to receive common units upon vesting, and "restricted" units, which are grants of common units restricted until the time of vesting. The phantom unit awards also include distribution equivalent rights ("DERs").

Subject to applicable earning criteria, a DER entitles the grantee to a cash payment equal to the cash distribution paid on an outstanding common unit prior to the vesting date of the underlying award. Recipients of restricted and phantom units are entitled to receive cash distributions paid on common units during the vesting period which are reflected initially as a reduction of partners' capital. Distributions paid on units which ultimately do not vest are reclassified as compensation expense. Awards granted to date are equity awards and, accordingly, the fair value of the awards as of the grant date is expensed over the vesting period.

In connection with each anniversary of joining the Board, restricted common units are granted to the independent directors. The units vest in one-third increments over three years. The following table includes information on outstanding grants made to the directors under the LTIP:

Grant Date	Number of Units	Weighted Average Grant Date Fair Value[1]	Grant Date Total Fair Value (in thousands)
December 2016	10,950	$ 6.85	$ 75
December 2017	15,306	$ 4.85	$ 74

(1) Fair value is the closing market price on the grant date of the awards.

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In addition, the independent directors received common unit grants that have no vesting requirement as part of their compensation. The following table includes information on grants made to the directors under the LTIP that have no vesting requirement:

Grant Date	Number of Units	Weighted Average Grant Date Fair Value(1)	Grant Date Total Fair Value (in thousands)
December 2016	10,220	$ 6.85	$ 70
December 2017	14,286	$ 4.85	$ 69

(1) Fair value is the closing market price on the grant date of the awards.

The Partnership also grants phantom units to employees. These grants are equity awards under ASC 718 – Stock Compensation, and, accordingly, the fair value of the awards as of the grant date is expensed over the vesting period. The following table includes information on the outstanding grants:

Grant Date	Number of Units	Weighted Average Grant Date Fair Value(1)	Grant Date Total Fair Value (in thousands)
March 2016	416,131	$ 4.77	$ 1,985
October 2016	9,960	$ 5.85	$ 58
March 2017	323,339	$ 7.15	$ 2,312
March 2018	457,984	$ 4.77	$ 2,185

(1) Fair value is the closing market price on the grant date of the awards.

The unrecognized estimated compensation cost of outstanding phantom and restricted units at March 31, 2018 was $3.7 million, which will be expensed over the remaining vesting period.

The Partnership's equity-based incentive compensation expense for each of the three months ended March 31, 2017 and 2018 was $0.5 million.

Activity pertaining to phantom and restricted common unit awards granted under the LTIP is as follows:

	Number of Units	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2017	923,551	$ 6.29
Granted	457,984	4.77
Vested	234,012	7.49
Forfeited	10,865	5.39
Nonvested at March 31, 2018	1,136,658	$ 5.88

12. EMPLOYEE BENEFIT PLANS

Under the Partnership’s 401(k) Plan, which was instituted in 2009, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the 401(k) Plan. The Partnership may match each employee’s contribution, up to a specified maximum, in full or on a partial basis. The Partnership recognized expense of $0.3 million for each of the three months ended March 31, 2017 and 2018, for discretionary contributions under the 401(k) Plan.

The Partnership may also make annual lump-sum contributions to the 401(k) Plan irrespective of the employee’s contribution match. The Partnership may make a discretionary annual contribution in the form of profit sharing calculated as a percentage of an employee’s eligible compensation. This contribution is retirement income under the qualified 401(k) Plan. Annual profit sharing contributions to the 401(k) Plan are submitted to and approved by the Board. The Partnership recognized expense of $0.2 million and $0.1 million for the three months ended March 31, 2017 and 2018, respectively, for discretionary profit sharing contributions under the 401(k) Plan.

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Under the Partnership's Employee Unit Purchase Plan (the "Unit Purchase Plan"), which was instituted in January 2015, employees have the opportunity to acquire or increase their ownership of common units representing limited partner interests in the Partnership. Eligible employees who enroll in the Unit Purchase Plan may elect to have a designated whole percentage, up to a specified maximum, of their eligible compensation for each pay period withheld for the purchase of common units at a discount to the then current market value. A maximum of 1,000,000 common units may be delivered under the Unit Purchase Plan, subject to adjustment for a recapitalization, split, reorganization, or similar event pursuant to the terms of the Unit Purchase Plan. The Partnership recognized compensation expense of less than $0.1 million for each of the three months ended March 31, 2017 and 2018, in connection with the Unit Purchase Plan.

13. FAIR VALUE MEASUREMENTS

The Partnership uses valuation techniques, such as the market approach (comparable market prices), the income approach (present value of future income or cash flow), and the cost approach (cost to replace the service capacity of an asset or replacement cost) to value assets and liabilities required to be measured at fair value, as appropriate. The Partnership uses an exit price when determining the fair value. The exit price represents amounts that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants.

The Partnership utilizes a three-tier fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three broad levels. The following is a brief description of those three levels:

Level 1	Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.
Level 2	Inputs other than quoted prices that are observable for these assets or liabilities, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.
Level 3	Unobservable inputs in which there is little market data, which requires the reporting entity to develop its own assumptions.

This hierarchy requires the use of observable market data, when available, to minimize the use of unobservable inputs when determining fair value. In periods in which they occur, the Partnership recognizes transfers into and out of Level 3 as of the end of the reporting period. There were no transfers during the three months ended March 31, 2018. Transfers out of Level 3 represent existing assets and liabilities that were classified previously as Level 3 for which the observable inputs became a more significant portion of the fair value estimates. Determining the appropriate classification of the Partnership's fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data.

The Partnership's recurring financial assets and liabilities subject to fair value measurements and the necessary disclosures are as follows (in thousands):

	Fair Value Measurements as of December 31, 2017			
Description	Total	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)

		(Level 1)		
Assets:				
Interest rate swap assets	$68	$ —	$ 68	$ —
Total swap assets	$68	$ —	$ 68	$ —
Liabilities:				
Interest rate swap liabilities	$225	$ —	$ 225	$ —
Total swap liabilities	$225	$ —	$ 225	$ —

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Description	Fair Value Measurements as of March 31, 2018			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Interest rate swap assets	$197	$ —	$ 197	$ —
Total swap assets	$197	$ —	$ 197	$ —

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. The Partnership has determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

At March 31, 2018, the carrying values on the unaudited condensed consolidated balance sheets for cash and cash equivalents (classified as Level 1), accounts receivable, and accounts payable approximate their fair value because of their short-term nature.

Based on the borrowing rates currently available to the Partnership for credit agreement debt with similar terms and maturities and consideration of the Partnership’s non-performance risk, long-term debt associated with the Partnership’s credit agreement at March 31, 2018, approximates its fair value. The fair value of the Partnership’s long-term debt was calculated using observable inputs (LIBOR for the risk-free component) and unobservable company-specific credit spread information. As such, the Partnership considers this debt to be Level 3.

14. OPERATING SEGMENTS

The Partnership’s operations consist of four operating segments: (i) asphalt terminalling services, (ii) crude oil terminalling services, (iii) crude oil pipeline services and (iv) crude oil trucking and producer field services.

ASPHALT TERMINALLING SERVICES —The Partnership provides asphalt product and residual fuel terminalling, storage and blending services at its 56 terminalling and storage facilities located in 26 states.

CRUDE OIL TERMINALLING SERVICES —The Partnership provides crude oil terminalling services at its terminalling facility located in Oklahoma.

CRUDE OIL PIPELINE SERVICES —The Partnership owns and operates pipeline systems that gather crude oil purchased by its customers and transports it to refiners, to common carrier pipelines for ultimate delivery to refiners or to terminalling facilities owned by the Partnership and others. The Partnership refers to its pipeline system located in Oklahoma and the Texas Panhandle as the Mid-Continent pipeline system. The Partnership previously owed and operated the East Texas pipeline system, which was located in Texas. On April 17, 2017, the Partnership sold the East Texas pipeline system. See Note 6 for additional information. Crude oil product sales revenues consist of sales proceeds recognized for the sale of crude oil to third-party customers.

CRUDE OIL TRUCKING AND PRODUCER FIELD SERVICES — The Partnership uses its owned and leased tanker trucks to gather crude oil for its customers at remote wellhead locations generally not covered by pipeline and gathering systems and to transport the crude oil to aggregation points and storage facilities located along pipeline gathering and transportation systems. Crude oil producer field services consist of a number of producer field services, ranging from gathering condensates from natural gas companies to hauling produced water to disposal wells. On April 24, 2018, the Partnership sold the producer field services business. See Note 18 for additional information.

The Partnership's management evaluates performance based upon operating margin, excluding amortization and depreciation, which includes revenues from related parties and external customers and operating expense, excluding depreciation and amortization. The non-GAAP measure of operating margin, excluding depreciation and amortization (in the aggregate and by segment) is presented in the following table. The Partnership computes the components of operating margin,

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excluding depreciation and amortization by using amounts that are determined in accordance with GAAP. The Partnership accounts for intersegment product sales as if the sales were to third parties, that is, at current market prices. A reconciliation of operating margin, excluding depreciation and amortization to income before income taxes, which is its nearest comparable GAAP financial measure, is included in the following table. The Partnership believes that investors benefit from having access to the same financial measures being utilized by management. Operating margin, excluding depreciation and amortization is an important measure of the economic performance of the Partnership's core operations. This measure forms the basis of the Partnership's internal financial reporting and is used by its management in deciding how to allocate capital resources among segments. Income before income taxes, alternatively, includes expense items, such as depreciation and amortization, general and administrative expenses and interest expense, which management does not consider when evaluating the core profitability of the Partnership's operations.

The following table reflects certain financial data for each segment for the periods indicated (in thousands):

	Three Months ended March 31,	
	2017	2018
Asphalt Terminalling Services		
Service revenue:		
Third-party revenue	$13,223	$5,132
Related-party revenue	13,332	6,321
Lease revenue:		
Third-party revenue	—	9,458
Related-party revenue	—	7,702
Total revenue for reportable segment	26,555	28,613
Operating expense, excluding depreciation and amortization	12,319	13,333
Operating margin, excluding depreciation and amortization	$14,236	$15,280
Total assets (end of period)	$145,815	$170,473
Crude Oil Terminalling Services		
Service revenue:		
Third-party revenue	$6,125	$4,585
Lease revenue:		
Third-party revenue	—	15
Total revenue for reportable segment	6,125	4,600
Operating expense, excluding depreciation and amortization	1,011	1,275
Operating margin, excluding depreciation and amortization	$5,114	$3,325
Total assets (end of period)	$70,518	$68,160

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	Three Months ended March 31, 2017	2018
Crude Oil Pipeline Services		
Service revenue:		
Third-party revenue	$2,605	$2,061
Related-party revenue	310	—
Lease revenue:		
Third-party revenue	—	235
Product sales revenue:		
Third-party revenue	3,650	3,508
Total revenue for reportable segment	6,565	5,804
Operating expense, excluding depreciation and amortization	3,242	2,785
Operating expense (intersegment)	170	442
Cost of product sales	3,139	2,637
Operating margin, excluding depreciation and amortization	$14	$(60)
Total assets (end of period)	$145,351	$116,845
Crude Oil Trucking and Producer Field Services		
Service revenue:		
Third-party revenue	$6,710	$5,540
Intersegment revenue	170	442
Lease revenue:		
Third-party revenue	—	97
Product sales revenue:		
Third-party revenue	385	6
Total revenue for reportable segment	7,265	6,085
Operating expense, excluding depreciation and amortization	7,268	6,375
Operating margin, excluding depreciation and amortization	$(3)	$(290)
Total assets (end of period)	$12,383	$6,113
Total operating margin, excluding depreciation and amortization(1)	$19,361	$18,255
Total segment revenues	$46,510	$45,102
Elimination of intersegment revenues	(170)	(442)
Consolidated revenues	$46,340	$44,660

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(1)The following table reconciles segment operating margin (excluding depreciation and amortization) to income before income taxes (in thousands):

	Three Months ended March 31, 2017	2018
Operating margin, excluding depreciation and amortization	$19,361	$18,255
Depreciation and amortization	(8,066)	(7,367)
General and administrative expense	(4,585)	(4,221)
Asset impairment expense	(28)	(616)
Loss on sale of assets	(125)	(236)
Interest expense	(3,030)	(3,569)

Gain on sale of unconsolidated affiliate	—	2,225
Equity earnings in unconsolidated affiliate	61	—
Income before income taxes	$3,588	$4,471

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15. COMMITMENTS AND CONTINGENCIES

The Partnership is from time to time subject to various legal actions and claims incidental to its business. Management believes that these legal proceedings will not have a material adverse effect on the financial position, results of operations or cash flows of the Partnership. Once management determines that information pertaining to a legal proceeding indicates that it is probable that a liability has been incurred and the amount of such liability can be reasonably estimated, an accrual is established equal to its estimate of the likely exposure.

The Partnership has contractual obligations to perform dismantlement and removal activities in the event that some of its asphalt product and residual fuel oil terminalling and storage assets are abandoned. These obligations include varying levels of activity including completely removing the assets and returning the land to its original state. The Partnership has determined that the settlement dates related to the retirement obligations are indeterminate. The assets with indeterminate settlement dates have been in existence for many years and with regular maintenance will continue to be in service for many years to come. Also, it is not possible to predict when demands for the Partnership's terminalling and storage services will cease, and the Partnership does not believe that such demand will cease for the foreseeable future. Accordingly, the Partnership believes the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, the Partnership cannot reasonably estimate the fair value of the associated asset retirement obligations. Management believes that if the Partnership's asset retirement obligations were settled in the foreseeable future the present value of potential cash flows that would be required to settle the obligations based on current costs are not material. The Partnership will record asset retirement obligations for these assets in the period in which sufficient information becomes available for it to reasonably determine the settlement dates.

16. INCOME TAXES

In relation to the Partnership's taxable subsidiary, the tax effects of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts at March 31, 2018, are presented below (dollars in thousands):

Deferred Tax Asset	
Difference in bases of property, plant and equipment	$464
Net operating loss carryforwards	5
Deferred tax asset	469
Less: valuation allowance	464
Net deferred tax asset	$5

The Partnership has considered the taxable income projections in future years, whether the carryforward period is so brief that it would limit realization of tax benefits, whether future revenue and operating cost projections will produce enough taxable income to realize the deferred tax asset based on existing service rates and cost structures, and the Partnership's earnings history exclusive of the loss that created the future deductible amount for the Partnership's subsidiary that is taxed as a corporation for purposes of determining the likelihood of realizing the benefits of the deferred tax assets. As a result of the Partnership's consideration of these factors, the Partnership has provided a valuation allowance against its deferred tax asset related to the difference in bases of property, plant and equipment as of March 31, 2018.

17. RECENTLY ISSUED ACCOUNTING STANDARDS

Except as discussed below and in the 2017 Form 10-K, there have been no new accounting pronouncements that have become effective or have been issued during the three months ended March 31, 2018, that are of significance or potential significance to the Partnership.

In May 2014, the FASB issued ASU 2014-09, “Revenue from Contracts with Customers.” The amendments in this update create Topic 606, Revenue from Contracts with Customers, and supersede the revenue recognition requirements in Topic 605, Revenue Recognition, including most industry-specific revenue recognition guidance throughout the Industry Topics of the Codification. In addition, the amendments supersede the cost guidance in Subtopic 605-35, Revenue Recognition-Construction-Type and Production-Type Contracts, and create new Subtopic 340-40, Other Assets and Deferred Costs-Contracts with Customers. In summary, the core principle of Topic 606 is that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Throughout 2015 and 2016, the FASB has issued a series of subsequent updates to the revenue recognition guidance in Topic 606, including ASU No. 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date,” ASU No. 2016-08, “Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net),” ASU No. 2016-10, “Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing,” ASU No. 2016-12, “Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients” and ASU No. 2016-20, “Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers.”

The amendments in ASU 2014-09, ASU 2016-08, ASU 2016-10, ASU 2016-12 and ASU 2016-20 are effective for public entities for annual reporting periods beginning after December 15, 2017, and for interim periods within that reporting period. The Partnership adopted this update in the three-month period ending March 31, 2018. See Note 3 for disclosures related to the adoption of this standard and the impact on the Partnership’s financial position, results of operations and cash flows.

In January 2016, the FASB issued ASU 2016-01, “Financial Instruments - Overall (Subtopic 825-10).” This update is intended to enhance the reporting model for financial instruments in order to provide users of financial statements with more decision-useful information. The amendments in the update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership adopted this update in the three-month period ending March 31, 2018, and there was no impact on the Partnership’s financial position, results of operations or cash flows.

In August 2016, the FASB issued ASU 2016-15, “Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments.” This update addresses the following eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies (including bank-owned life insurance policies); distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle.

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This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership adopted this update in the three-month period ending March 31, 2018, and there was no impact on the Partnership's financial position, results of operations or cash flows.

In October 2016, the FASB issued ASU 2016-16, "Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other than Inventory." This update is intended to improve the accounting for the income tax consequences of intra-entity transfers of assets other than inventory. The amendments in the update eliminate the prohibition of recognizing current and deferred income taxes for an intra-entity asset transfer other than inventory until the asset has been sold to an outside party. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership adopted this update in the three-month period ending March 31, 2018, and there was no impact on the Partnership's financial position, results of operations or cash flows.

In November 2016, the FASB issued ASU 2016-18, "Statement of Cash Flows (Topic 230): Restricted Cash (a Consensus of the FASB Emerging Issues Task Force)." This update requires that a 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. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership adopted this update in the three-month period ending March 31, 2018, and there was no impact on the Partnership's financial position, results of operations or cash flows.

In January 2017, the FASB issued ASU 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business." This update clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership adopted this update in the three-month period ending March 31, 2018, and there was no impact on the Partnership's financial position, results of operations or cash flows.

In February 2017, the FASB issued ASU 2017-05, "Other Income - Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20)." This update clarifies the scope of Subtopic 610-20 and adds guidance for partial sales of nonfinancial assets. Subtopic 610-20, which was issued in May 2014 as a part of ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)," provides guidance for recognizing gains and losses from the transfer of nonfinancial assets in contracts with noncustomers. The amendments in ASU 2017-05 are effective for public entities for annual reporting periods beginning after December 15, 2017, and for interim periods within that reporting period. Early application is permitted for annual reporting periods beginning after December 15, 2016. The Partnership adopted this update in the three-month period ending March 31, 2018, and there was no impact on the Partnership's financial position, results of operations or cash flows.

In May 2017, the FASB issued ASU 2017-09, "Compensation - Stock Compensation (Topic 718): Scope of Modification Accounting." This update provides clarity and reduces both diversity in practice and cost and complexity when applying the guidance of Topic 718, Compensation - Stock Compensation, to a change in the terms or conditions of a share-based payment award. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership adopted this update in the three-month period ending March 31, 2018, and there was no impact on the Partnership's financial position, results of operations or cash flows.

18. SUBSEQUENT EVENTS

Sale of Producer Field Services

On April 24, 2018, the Partnership sold its producer field services business for approximately $3.0 million. Included in assets held for sale as of March 31, 2018, were property, plant and equipment of $1.3 million and finite-lived intangible assets of $0.2 million. The Partnership recognized a $0.4 million gain on the sale.

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

As used in this quarterly report, unless we indicate otherwise: (1) "Blueknight Energy Partners," "our," "we," "us" and similar terms refer to Blueknight Energy Partners, L.P., together with its subsidiaries, (2) our "General Partner" refers to Blueknight Energy Partners G.P., L.L.C., (3) "Ergon" refers to Ergon, Inc., its affiliates and subsidiaries (other than our General Partner and us) and (4) "Vitol" refers to Vitol Holding B.V., its affiliates and subsidiaries. The following discussion analyzes the historical financial condition and results of operations of the Partnership and should be read in conjunction with our financial statements and notes thereto, and Management's Discussion and Analysis of Financial Condition and Results of Operations presented in our Annual Report on Form 10-K for the year ended December 31, 2017, which was filed with the Securities and Exchange Commission (the "SEC") on March 8, 2018 (the "2017 Form 10-K").

Forward-Looking Statements

This report contains forward-looking statements. Statements included in this quarterly report that are not historical facts (including any statements regarding plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), including, without limitation, the information set forth in this Management's Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "may," "will," "should," "believe," "expect," "intend," "anticipate," "estimate," "continue," or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition, or state other "forward-looking" information. We and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

Such forward-looking statements are subject to various risks and uncertainties that could cause actual results to differ materially from those anticipated as of the date of the filing of this report. Although we believe that the expectations reflected in these forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will prove to be correct. Important factors that could cause our actual results to differ materially from the expectations reflected in these forward-looking statements include, among other things, those set forth in "Part I, Item 1A. Risk Factors" in the 2017 Form 10-K.

All forward-looking statements included in this report are based on information available to us on the date of this report. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

Overview

We are a publicly traded master limited partnership with operations in 27 states. We provide integrated terminalling, gathering and transportation services for companies engaged in the production, distribution and marketing of liquid asphalt and crude oil. We manage our operations through four operating segments: (i) asphalt terminalling services, (ii) crude oil terminalling services, (iii) crude oil pipeline services and (iv) crude oil trucking and producer field services.

Potential Impact of Recent Crude Oil Market Price Changes and Other Matters on Future Revenues

Since June 2014, the market price of West Texas Intermediate crude oil has fluctuated significantly from a peak of approximately $108 per barrel to a low of approximately $30 per barrel (as of May 3, 2018, the price per barrel was approximately $68). In addition to changes in the price of crude oil and the forward pricing curve, there has been significant volatility in the overall energy industry and specifically in publicly traded midstream energy partnerships. As a result there are a number of trends that may impact our partnership in the near term. These include the overall market price for crude oil and whether or not the forward price curve is in contango (in which future prices are higher than current prices and a premium is placed on storing product and selling at a later time) or backwardated (in which the current crude oil price per barrel is higher than the future price per barrel and a premium is placed on delivering product to market and selling as soon as possible), changes in production and the demand for transportation capacity in the areas in which we serve and overall changes in our cost of capital. As of March 31, 2018, the forward price curve is slightly backwardated. We expect these changes to have near-term impacts as discussed below.

Asphalt Terminalling Services - Although there is no direct correlation between the price of crude oil and the price of asphalt, the asphalt industry tends to benefit from a lower crude oil price environment, a strong economy and an increase in infrastructure spending. As a result, we do not expect recent changes in the price of crude oil to significantly impact our asphalt terminalling services operating segment.

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Crude Oil Terminalling Services - A contango crude oil curve tends to favor the crude oil storage business as crude oil marketers are incentivized to store crude oil during the current month and sell into the future month. As a result of the decrease in the price of crude oil and the change in the crude oil futures pricing curve, our weighted average storage rates increased from September 2014 to March 2016. Since March of 2016, the crude oil curve has generally been in a shallow contango or backwardation. In these shallow contango or backwardation markets there is no clear incentive for marketers to store barrels. As of March 31, 2018, the forward price curve is slightly backwardated. A shallow contango or a backwardated market may impact our ability to re-contract expiring contracts and/or decrease the storage rate at which we are able to re-contract. Total Cushing inventories peaked at just under 70 million barrels stored in March of 2017 and bottomed at approximately 30 million barrels stored in January of 2018. Furthermore, current storage levels are significantly below the 5-year average for storage volumes. As a result of the current shape of the curve and lessened overall demand for Cushing storage, we anticipate a weak recontracting environment which may impact both the volume of storage we are able to successfully recontract and the rate at which we recontract. These periods are typically fairly short-lived but there can be no assurance as to the timing of a rebound in the Cushing storage market.

Crude Oil Pipeline Services - In late April 2016, as a precautionary measure, we suspended service on a segment of our Mid-Continent pipeline system due to discovery of a pipeline exposure caused by heavy rains and the erosion of a riverbed in southern Oklahoma. There was no damage to the pipeline and no loss of product. In the second quarter of 2016, we took action to mitigate the service suspension and worked with customers to divert volumes and, in certain circumstances, transported volumes to a third-party pipeline system via truck. In addition, the term of the throughput and deficiency agreement on our Eagle North pipeline system expired on June 30, 2016, and in July 2016, we completed a connection of the southeastern most portion of our Mid-Continent pipeline system to our Eagle North pipeline system and concurrently reversed the Eagle North pipeline system.

We are currently operating one Oklahoma mainline system, which is a combination of both the Mid-Continent and Eagle North pipeline systems, instead of two separate systems, providing us with a current capacity of approximately 20,000 to 25,000 barrels per day (Bpd). We are working to restore service of the second Oklahoma pipeline system and expect to put the line back in service by the end of the second quarter of 2018, increasing the transportation capacity of our pipeline systems by approximately 20,000 Bpd. The ability to fully utilize the capacity of these systems may be impacted by the market price of crude oil and producers' decisions to increase or decrease production in the areas we serve.

On April 3, 2017, Advantage Pipeline, L.L.C., in which we owned an approximate 30% equity ownership interest, was acquired by a joint venture formed by affiliates of Plains All American Pipeline, L.P. and Noble Midstream Partners LP. We received cash proceeds at closing from the sale of our approximate 30% equity ownership interest in Advantage Pipeline of approximately $25.3 million and recorded a gain on the sale of the investment of $4.2 million. Approximately 10% of the gross sales proceeds were held in escrow, subject to certain post-closing settlement terms and conditions. We received approximately $1.1 million of the funds held in escrow in August 2017 and our remaining balance of $2.2 million in January 2018.

Crude Oil Trucking and Producer Field Services - We continue to experience increased competition in this segment, which has resulted in further pressures on the rates we are able to charge our customers for services provided. In December 2017, we evaluated our producer field services business for impairment and recognized an impairment expense of $2.4 million to record our assets at their estimated fair value. On April 24, 2018, we sold our producer field services business, which was included in assets held for sale at March 31, 2018.

Our Revenues

Our revenues consist of (i) terminalling revenues, (ii) gathering, transportation and producer field services revenues, (iii) product sales revenues and (iv) fuel surcharge revenues. For the three months ended March 31, 2018, the Partnership recognized revenues of $14.0 million for services provided to Ergon, with the remainder of our services being provided to third parties.

Terminalling revenues consist of (i) storage service fees resulting from short-term and long-term contracts for committed space that may or may not be utilized by the customer in a given month and (ii) throughput fees to pump crude oil to connecting carriers or to deliver asphalt product out of our terminals. We earn terminalling revenues in two of our segments: (i) asphalt terminalling services and (ii) crude oil terminalling services. Storage service revenues are recognized as the services are provided on a monthly basis. Throughput fees in our asphalt terminalling services segment are recognized straight-line over time. Throughput fees in our crude oil terminalling services segments are recognized as the crude oil is delivered out of our terminal.

We have leases and terminalling agreements with customers for all of our 56 asphalt facilities, including 26 facilities under contract with Ergon. Lease and terminalling agreements related to 16 of these facilities have terms that expire at the end of 2018, while the agreements relating to our additional 40 facilities have on average five years remaining under their terms. Fifteen of the contracts that expire in 2018 are with Ergon. We may not be able to extend, renegotiate or replace these contracts when they expire and the terms of any renegotiated contracts may not be as favorable as the contracts they replace. We operate the asphalt facilities pursuant to the terminalling agreements, while our contract counterparties operate the asphalt facilities that are subject to lease agreements.

Through April 30, 2018, we had approximately 4.9 million barrels of crude oil storage under service contracts. Storage contracts with Vitol represented 2.2 million barrels of crude oil storage capacity under a contract that expired on April 30, 2018. We were notified by Vitol of its intent to exit our terminal at the expiration of the contract, and we are in the process of that transition. Service contracts relating to an additional 1.9 million barrels also expire in 2018.

We are in negotiations to either extend contracts with other existing customers or enter into new customer contracts for the agreements expiring in 2018; however, there is no certainty that we will have success in contracting available capacity or that extended or new contracts will be at the same or similar rates as the expiring contracts. If we are unable to renew the majority of the expiring storage contracts, we may experience lower utilization of our assets which could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our common units, results of operations and ability to conduct our business.

Gathering and transportation services revenues consist of service fees recognized for the gathering of crude oil for our customers and the transportation of crude oil to refiners, to common carrier pipelines for ultimate delivery to refiners or to terminalling facilities owned by us and others. We earn gathering and transportation revenues in two of our segments: (i) crude oil pipeline services and (ii) crude oil trucking and producer field services (as noted above we sold the producer field services business in April 2018). Revenue for the gathering and transportation of crude oil is recognized when the service is performed and is based upon regulated and non-regulated tariff rates and the related transport volumes. Producer field services revenue consists of a number of services ranging from gathering condensates from natural gas producers to hauling produced water to disposal wells. Revenue for producer field services is recognized when the service is performed.

During the three months ended March 31, 2018, we transported approximately 23,000 Bpd on our Mid-Continent pipeline system, which is an increase of 5% compared to the three months ended March 31, 2017. We are working to restore service of the second Oklahoma pipeline system and expect to put the line back in service by the end of the second quarter of 2018, increasing the transportation capacity of our pipeline systems by approximately 20,000 Bpd. See Crude oil pipeline services segment within our results of operations discussion for additional detail. Vitol accounted for 56% and 57% of volumes transported in our pipelines in the three months ended March 31, 2017 and 2018, respectively.

For the three months ended March 31, 2018, we transported approximately 23,000 Bpd on our crude oil transport trucks, an increase of 5% as compared to the three months ended March 31, 2017. Vitol accounted for approximately 45% and 30% of volumes transported by our crude oil transport trucks in the three months ended March 31, 2017 and 2018, respectively. When our second Oklahoma pipeline system resumes service, we anticipate additional increases in volumes transported by our crude oil transport trucks as we gather barrels to be transported on this pipeline.

Product sales revenues are comprised of (i) revenues recognized for the sale of crude oil to our customers that we purchase at production leases and (ii) revenue recognized in buy/sell transactions with our customers. We earn product sales revenue in our crude oil pipeline services operating segment. Product sales revenue is recognized for products upon delivery and when the customer assumes the risks and rewards of ownership.

Fuel surcharge revenues are comprised of revenues recognized for the reimbursement of fuel and power consumed to operate our asphalt terminals. We recognize fuel surcharge revenues in the period in which the related fuel and power expenses are incurred.

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Our Expenses

Operating expenses decreased slightly by 2% for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017. This is primarily a result of a decrease in depreciation due to certain assets reaching the end of their depreciable lives as well as a decrease in vehicle expenses due to operating a smaller fleet. General and administrative expenses remained relatively consistent for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017. Our interest expense increased by $0.5 million for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017. See Interest expense within our results of operations discussion for additional detail regarding the factors that contributed to the increase in interest expense in 2018.

Income Taxes

As part of the process of preparing the unaudited condensed consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which our subsidiary that is taxed as a corporation operates. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included in our unaudited condensed consolidated balance sheets. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. Unless we believe that recovery is more likely than not, we must establish a valuation allowance. To the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provisions in the unaudited condensed consolidated statements of operations.

Under ASC 740 – Accounting for Income Taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists, (a) the more positive evidence is necessary and (b) the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion or all of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years;
- whether the carryforward period is so brief that it would limit realization of tax benefits;
- future revenue and operating cost projections that will produce more than enough taxable income to realize the deferred tax asset based on existing service rates and cost structures; and
- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition.

Based on the consideration of the above factors for our subsidiary that is taxed as a corporation for purposes of determining the likelihood of realizing the benefits of the deferred tax assets, we have provided a valuation allowance against our deferred tax asset related to the difference in bases of property, plant and equipment as of March 31, 2018.

Distributions

The amount of distributions we pay and the decision to make any distribution is determined by the Board of Directors of our General Partner (the “Board”), which has broad discretion to establish cash reserves for the proper conduct of our business and for future distributions to our unitholders. In addition, our cash distribution policy is subject to restrictions on distributions under our credit agreement.

On April 23, 2018, the Board approved a distribution of $0.17875 per outstanding Preferred Unit for the three months ended March 31, 2018. We will pay this distribution on May 15, 2018, to unitholders of record as of May 4, 2018. The total distribution will be approximately $6.4 million, with approximately $6.3 million and $0.1 million paid to our preferred unitholders and General Partner, respectively.

In addition, on April 23, 2018, the Board approved a cash distribution of $0.1450 per outstanding common unit for the three months ended March 31, 2018. We will pay this distribution May 15, 2018, to unitholders of record on May 4, 2018. The total distribution will be approximately $6.3 million, with approximately $5.8 million and $0.3 million paid to our common unitholders and General Partner, respectively, and $0.2 million paid to holders of phantom and restricted units pursuant to awards granted under our Long-Term Incentive Plan.

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Results of Operations

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as “non-GAAP financial measures” in its evaluation of past performance and prospects for the future. The primary measure used by management is operating margin, excluding depreciation and amortization.

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow; (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These additional financial measures are reconciled to the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our unaudited condensed consolidated financial statements and footnotes.

The table below summarizes our financial results for the three months ended March 31, 2017 and 2018, reconciled to the most directly comparable GAAP measure:

Operating Results	Three Months ended March 31,		Favorable/(Unfavorable)	
(dollars in thousands)	2017	2018	$	%
Operating margin, excluding depreciation and amortization:				
Asphalt terminalling services	$14,236	$15,280	$ 1,044	7 %
Crude oil terminalling services	5,114	3,325	(1,789)	(35)%
Crude oil pipeline services	14	(60)	(74)	(529)%
Crude oil trucking and producer field services	(3)	(290)	(287)	(9,567)%
Total operating margin, excluding depreciation and amortization	19,361	18,255	(1,106)	(6)%
Depreciation and amortization	(8,066)	(7,367)	699	9 %
General and administrative expense	(4,585)	(4,221)	364	8 %
Asset impairment expense	(28)	(616)	(588)	(2,100)%
Loss on sale of assets	(125)	(236)	(111)	(89)%
Operating income	6,557	5,815	(742)	(11)%
Other income (expenses):				
Equity earnings in unconsolidated affiliate	61	—	(61)	(100)%
Gain on sale of unconsolidated affiliate	—	2,225	2,225	N/A
Interest expense	(3,030)	(3,569)	(539)	(18)%
Provision for income taxes	(46)	(29)	17	37 %
Net income	$3,542	$4,442	$ 900	25 %

For the three months ended March 31, 2018, operating margin, excluding depreciation and amortization, increased in our asphalt terminalling services segment as compared to the same period in 2017 primarily due to the acquisition of two asphalt facilities, one from Ergon in December 2017 and one from a third party in March 2018, as well as the conversion of another facility from a lease agreement to a storage, handling and throughput agreement. These increases were partially offset by lower operating margins in our other segments. The decrease in our crude oil terminalling services operating margin, excluding depreciation and amortization,was primarily due to lower storage rates. The crude oil pipeline services margin, excluding depreciation and amortization, continues to be affected by the suspended service on our Mid-Continent pipeline system due to the discovery of a pipeline exposure in April 2016. Crude oil trucking and producer field services operating margin, excluding depreciation and amortization, decreased due to decreases in the average miles hauled per transaction, which results in lower revenues per barrel transported.

A more detailed analysis of changes in operating margin by segment follows.

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Analysis of Operating Segments

Asphalt terminalling services segment

Our asphalt terminalling services segment operations generally consist of fee-based activities associated with providing terminalling services, including storage, blending, processing and throughput services, for asphalt product and residual fuel oil. Revenue is generated through operating lease contracts and storage, throughput and handling contracts.

The following table sets forth our operating results from our asphalt terminalling services segment for the periods indicated:

Operating results	Three Months ended March 31,		Favorable/(Unfavorable)	
(dollars in thousands)	2017	2018	$	%
Service revenue:				
Third-party revenue	$13,223	$5,132	$ (8,091)	(61)%
Related-party revenue	13,332	6,321	(7,011)	(53)%
Lease revenue:				
Third-party revenue	—	9,458	9,458	N/A
Related-party revenue	—	7,702	7,702	N/A
Total revenue	26,555	28,613	2,058	8 %
Operating expense, excluding depreciation and amortization	12,319	13,333	(1,014)	(8)%
Operating margin, excluding depreciation and amortization	$14,236	$15,280	$ 1,044	7 %

The following is a discussion of items impacting asphalt terminalling services segment operating margin for the periods indicated:

- Due to the adoption of ASC 606 - Revenue from Contracts with Customers, revenue from contracts with customers is now presented separately from lease revenue. Prior periods were not reclassified.

- Overall revenues have increased for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017, primarily due to the acquisition of two asphalt facilities, one from Ergon in December 2017 and one from a third party in March 2018. In addition, a third facility converted from a lease contract to a storage, throughput and handling contract, which generates higher gross revenue. Third-party revenues also increased overall due to increases in reimbursement revenues.

- Operating expenses increased for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017, primarily as a result of the acquisitions noted above. In addition, ad valorem taxes increased due to revised tax assessments.

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Crude oil terminalling services segment

Our crude oil terminalling services segment operations generally consist of fee-based activities associated with providing terminalling services, including storage, blending, processing and throughput services for crude oil. Revenue is generated through short- and long-term storage contracts.

The following table sets forth our operating results from our crude oil terminalling services segment for the periods indicated:

Operating results	Three Months ended March 31,		Favorable/(Unfavorable)	
(dollars in thousands)	2017	2018	$	%
Service revenue:				
Third-party revenue	$6,125	$4,585	$ (1,540)	(25)%
Lease revenue:				
Third-party revenue	—	15	15	N/A
Total revenue	6,125	4,600	(1,525)	(25)%
Operating expense, excluding depreciation and amortization	1,011	1,275	(264)	(26)%
Operating margin, excluding depreciation and amortization	$5,114	$3,325	$ (1,789)	(35)%
Average crude oil stored per month at our Cushing terminal (in thousands of barrels)	5,954	1,843	(4,111)	(69)%
Average crude oil delivered to our Cushing terminal (in thousands of barrels per day)	43	82	39	91 %

The following is a discussion of items impacting crude oil terminalling services segment operating margin for the periods indicated:

- Total revenues for three months ended March 31, 2018 have decreased as compared to the same period in 2017 due to a decrease in market rates for storage contracts.

- Operating expenses for the three months ended March 31, 2018, increased as compared to the three months ended March 31, 2017, primarily due to the timing of routine tank maintenance expense.

- As of May 3, 2018, we had approximately 2.7 million barrels of crude oil storage under service contracts with remaining terms ranging from two months to 44 months, including 1.9 million barrels of crude oil storage contracts that expire in 2018.

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Crude oil pipeline services segment

Our crude oil pipeline services segment operations include both service and product sales revenue. Service revenue generally consists of tariffs and other fees associated with transporting crude oil products on pipelines. Product sales revenue is comprised of (i) revenues recognized for the sale of crude oil to our customers that we purchase at production leases and (ii) revenue recognized in buy/sell transactions with our customers. Product sales revenue is recognized for products upon delivery and when the customer assumes the risks and rewards of ownership.

The following table sets forth our operating results from our crude oil pipeline services segment for the periods indicated:

Operating results	Three Months ended March 31,		Favorable/(Unfavorable)	
(dollars in thousands)	2017	2018	$	%
Service revenue:				
Third-party revenue	$2,605	$2,061	$ (544)	(21)%
Related-party revenue	310	—	(310)	(100)%
Product sales revenue:				
Third-party revenue	3,650	3,508	(142)	(4)%
Lease revenue:				
Third-party revenue	—	235	235	N/A
Total revenue	6,565	5,804	(761)	(12)%
Operating expense, excluding depreciation and amortization	3,242	2,785	457	14 %
Operating expense (intersegment)	170	442	(272)	(160)%
Cost of product sales	3,139	2,637	502	16 %
Operating margin, excluding depreciation and amortization	$14	$(60)	$ (74)	(529)%
Average throughput volume (in thousands of barrels per day)				
Mid-Continent	22	23	1	5 %
East Texas	3	—	(3)	(100)%

The following is a discussion of items impacting crude oil pipeline services segment operating margin for the periods indicated:

- In late April 2016, as a precautionary measure we suspended service on our Mid-Continent pipeline system due to discovery of a pipeline exposure caused by heavy rains and the erosion of a riverbed in southern Oklahoma. There was no damage to the pipe and no loss of product. In the second quarter of 2016, we took action to mitigate the service suspension and worked with customers to divert volumes and, in certain circumstances, transported volumes to a third-party pipeline system via truck. In addition, the term of the throughput and deficiency agreement on our Eagle North pipeline system expired on June 30, 2016, and in July 2016 we completed a connection of the southeastern-most portion of our Mid-Continent pipeline system to our Eagle North pipeline system and concurrently reversed the Eagle North pipeline system. This enabled us to recapture diverted volumes and deliver those barrels to Cushing, Oklahoma. We are currently operating one Oklahoma mainline system, which is a combination of both the Mid-Continent and Eagle North pipeline systems, instead of two separate systems, providing us with a current capacity of approximately 20,000 to 25,000 Bpd. We are working to restore service of the second Oklahoma pipeline system and expect to put the line back in service by the end of the second quarter of 2018, increasing the transportation capacity of our pipeline systems by approximately 20,000 Bpd. The ability to fully utilize the capacity of these systems may be impacted by the market price of crude oil and producers’ decisions to increase or decrease production in the areas we serve.

- Revenues for the three months ended March 31, 2018, decreased as compared to the three months ended March 31, 2017, due to more volumes being moved under contracts with lower rates, which more than offset the increase in throughput.

- On April 18, 2017, we sold the East Texas pipeline system. We received cash proceeds at closing of approximately $4.8 million and recorded a gain of less than $0.1 million. The sale of the East Texas pipeline system resulted in

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decreased service revenues of $0.3 million for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017.

- Operating expenses decreased for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017, by $0.4 million as a result of the sale of the East Texas pipeline system and by $0.2 million as a result of the sale of our investment in Advantage Pipeline, for which we provided operational and administrative services through August 1, 2017.

Crude oil trucking and producer field services segment

Our crude oil trucking and producer field services segment operations generally consist of fee-based activity associated with transporting crude oil products on trucks. Revenues are generated primarily through transportation fees.

The following table sets forth our operating results from our crude oil trucking and producer field services segment for the periods indicated:

Operating results	Three Months ended March 31,		Favorable/(Unfavorable)	
(dollars in thousands)	2017	2018	$	%
Service revenue:				
Third-party revenue	$6,710	$5,540	$ (1,170)	(17)%
Intersegment revenue	170	442	272	160 %
Product sales revenue:				
Third-party revenue	385	6	(379)	(98)%
Lease revenue:				
Third-party revenue	—	97	97	N/A
Total revenue	7,265	6,085	(1,180)	(16)%
Operating expense, excluding depreciation and amortization	7,268	6,375	893	12 %
Operating margin, excluding depreciation and amortization	$(3)	$(290)	$ (287)	(9,567)%
Average volume (in thousands of barrels per day)	22	23	1	5 %

The following is a discussion of items impacting crude oil trucking and producer field services segment operating margin for the periods indicated:

- Service revenues have decreased despite an increase in volumes as the volumes hauled in 2018 were, on average, over a shorter distance than in 2017, which results in lower revenue per barrel transported.

- Employment costs and vehicle-related expenses decreased for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017, as we reduced our headcount and fleet size to better match demand.

- Product sales revenues for the three months ended March 31, 2017, were the result of crude oil sales in our field services business, and there were minimal such sales in the three months ended March 31, 2018.

Other Income and Expenses

Depreciation and amortization expense. Depreciation and amortization decreased by $0.7 million to $7.4 million for the three months ended March 31, 2018, compared to $8.1 million for the three months ended March 31, 2017. This decrease is primarily the result of certain assets reaching the end of their depreciable lives.

General and administrative expenses. General and administrative expenses were relatively consistent at $4.2 million for the three months ended March 31, 2018, compared to $4.6 million for the three months ended March 31, 2017, with the change primarily consisting of decreases in legal, audit, and compensation expenses.

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Asset impairment expense. Asset impairment expense was $0.6 million and less than $0.1 million for the three months ended March 31, 2018 and 2017, respectively. Asset impairment expense for 2018 included approximately $0.4 million related to the value of obsolete trucking stations, as well as $0.2 million related to an intangible customer contract asset that was not renewed.

Loss on sale of assets. Loss on sale of assets was $0.2 million and $0.1 million for the three months ended March 31, 2018 and 2017, respectively. Losses in both periods were primarily comprised of sales of surplus, used property and equipment.

Equity earnings in unconsolidated affiliate/Gain on sale of unconsolidated affiliate. The equity earnings are attributable to our former investment in Advantage Pipeline. On April 3, 2017, we sold our investment in Advantage Pipeline and received cash proceeds at closing from the sale of approximately $25.3 million, recognizing a gain on sale of unconsolidated affiliate of $4.2 million. Approximately 10% of the gross sale proceeds were held in escrow, subject to certain post-closing settlement terms and conditions. We received approximately $1.1 million of the funds held in escrow in August 2017, for which we recognized an additional gain on sale of unconsolidated affiliate during the three months ended September 30, 2017. We received approximately $2.2 million for the pro rata portion of the remaining net escrow proceeds in January 2018, for which we recognized an additional gain on sale of unconsolidated affiliate during the three months ended March 31, 2018.

Interest expense. Interest expense represents interest on borrowings under our credit agreement as well as amortization of debt issuance costs and unrealized gains and losses related to the change in fair value of interest rate swaps.

Total interest expense for the three months ended March 31, 2018, increased by $0.5 million compared to the three months ended March 31, 2017. The increase was driven by additional interest on our credit agreement of $0.6 million due to increases in our average debt outstanding and the weighted average interest rate under our credit agreement. In addition, during the three months ended March 31, 2018, we recorded unrealized gains of $0.4 million due to the change in fair value of interest rate swaps compared to unrealized gains of $0.8 million during the three months ended March 31, 2017. These increases in interest expense were partially offset by a decrease in monthly net interest payments on the interest rate swaps of $0.4 million for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017. Also included in interest expense is the amortization of debt issuance costs of $0.3 million for both periods.

Effects of Inflation

In recent years, inflation has been modest and has not had a material impact upon the results of our operations.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

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Liquidity and Capital Resources

Cash Flows and Capital Expenditures

The following table summarizes our sources and uses of cash for the three months ended March 31, 2017 and 2018:

	Three Months ended March 31,	
	2017	2018
	(in millions)	
Net cash provided by operating activities	$7.5	$9.9
Net cash used in investing activities	$(1.2)	$(24.3)
Net cash provided by (used in) financing activities	$(6.8)	$13.9

Operating Activities. Net cash provided by operating activities increased to $9.9 million for the three months ended March 31, 2018, as compared to $7.5 million for the three months ended March 31, 2017, due to increased net income.

Investing Activities. Net cash used in investing activities was $24.3 million for the three months ended March 31, 2018, as compared to $1.2 million for the three months ended March 31, 2017. On March 7, 2018, we acquired an asphalt terminalling facility from a third party for $22.0 million. Capital expenditures for the three months ended March 31, 2018 and 2017, included gross maintenance capital expenditures of $1.8 million and $1.6 million, respectively, and expansion capital expenditures of $2.8 million and $2.4 million, respectively.

Financing Activities. Net cash provided by financing activities was $13.9 million for the three months ended March 31, 2018, as compared to net cash used in financing activities of $6.8 million for the three months ended March 31, 2017. Cash provided by financing activities for the three months ended March 31, 2018, consisted primarily of net borrowings on long-term debt of $27.0 million partially offset by $12.6 million in distributions to our unitholders. Net cash used in financing activities for the three months ended March 31, 2017, consisted primarily of $12.3 million in distributions to our unitholders partially offset by net borrowings on long-term debt of $6.0 million.

Our Liquidity and Capital Resources

Cash flows from operations and from our credit agreement are our primary sources of liquidity. At March 31, 2018, we had a working capital deficit of $0.4 million. This is primarily a function of our approach to cash management.

At March 31, 2018, we had approximately $113.9 million of availability under our credit agreement, and we could borrow an additional $23.7 million and still remain within our covenant restrictions As of May 3, 2018, we have aggregate unused commitments under our revolving credit facility of approximately $119.9 million and cash on hand of approximately $1.8 million. The credit agreement is scheduled to mature on May 11, 2022. As previously indicated, because the current forward price curve for crude oil is slightly backwardated and total Cushing storage volumes are below the 5-year average, we are anticipating a relatively weak recontracting environment which may impact both the volume of storage and the storage rate we are able to successfully recontract in 2018. These periods are typically fairly short-lived, but there can be no assurance as to the timing of a rebound in the Cushing storage market. As of May 3, 2018, we had approximately 2.7 million barrels of crude oil storage under service contracts of our total capacity of 6.6 million barrels, including 1.9 million barrels of crude oil storage contracts that expire in 2018.

As discussed in Note 7 to our unaudited condensed consolidated financial statements, our credit agreement includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. As of the end of the first quarter of 2018, we were in full compliance with all financial covenants. However, with the current weakness in crude oil storage rates, we believe that it is possible that we may fall out of compliance with these financial covenants as early as the third quarter of 2018. Failure to remain in compliance with the financial covenants could constrain our operating flexibility, our ability to fund our business operations and could cause the amounts outstanding under the credit agreement, which was $334.6 million as of March 31, 2018, to become immediately due and payable.

In light of this, we are considering options to enhance our financial flexibility and fund our operations, including a potential sale of assets, a reduction in the distribution rate that would be paid to the Partnership's common unitholders, and/or the need to amend the financial covenants under the credit agreement. Any amendment of the credit agreement may increase the cost of credit provided under the credit agreement and related expenses, which may adversely impact our profitability.

Capital Requirements. Our capital requirements consist of the following:

- maintenance capital expenditures, which are capital expenditures made to maintain the existing integrity and operating capacity of our assets and related cash flows, further extending the useful lives of the assets; and
- expansion capital expenditures, which are capital expenditures made to expand the operating capacity or revenue of existing or new assets, whether through construction, acquisition or modification.

Expansion capital expenditures for organic growth projects, net of reimbursable expenditures of $0.1 million, totaled $2.7 million in the three months ended March 31, 2018, compared to $2.3 million in the three months ended March 31, 2017. We currently expect our expansion capital expenditures for organic growth projects to be approximately $17.0 million to $22.0 million, inclusive of anticipated crude oil purchases for pipeline linefill and the Cushing terminal operational needs and net of reimbursable expenditures, for all of 2018. Maintenance capital expenditures totaled $1.6 million, net of reimbursable expenditures of $0.2 million, in the three months ended March 31, 2018, compared to $1.3 million in the three months ended March 31, 2017. We currently expect maintenance capital expenditures to be approximately $8.0 million to $10.0 million, net of reimbursable expenditures, for all of 2018.

Our Ability to Grow Depends on Our Ability to Access External Expansion Capital. Our partnership agreement requires that we distribute all of our available cash to our unitholders. Available cash is reduced by cash reserves established by our General Partner to provide for the proper conduct of our business (including for future capital expenditures) and to comply with the provisions of our credit agreement. We may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations because we distribute all of our available cash.

Recent Accounting Pronouncements

For information regarding recent accounting developments that may affect our future financial statements, see Note 17 to our unaudited condensed consolidated financial statements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

We are exposed to market risk due to variable interest rates under our credit agreement.

As of May 3, 2018, we had $328.6 million outstanding under our credit agreement that was subject to a variable interest rate. Borrowings under our credit agreement bear interest, at our option, at either the reserve adjusted eurodollar rate (as defined in the credit agreement) plus an applicable margin or the alternate base rate (the highest of the agent bank's prime rate, the federal funds effective rate plus 0.5%, and the 30-day eurodollar rate plus 1%) plus an applicable margin. Interest rate swap agreements are used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. In March 2014, we entered into two interest rate swap agreements with an aggregate notional value of $200.0 million. The first agreement became effective June 28, 2014, and matures on June 28, 2018. Under the terms of the first interest rate swap agreement, we pay a fixed rate of 1.45% and receive one-month LIBOR with monthly settlement. The second agreement became effective January 28, 2015, and matures on January 28, 2019. Under the terms of the second interest rate swap agreement, we pay a fixed rate of 1.97% and receive one-month LIBOR with monthly settlement. The fair market value of the interest rate swaps at March 31, 2018, consists of a current asset of $0.2 million and is recorded in other current assets on our unaudited condensed consolidated balance sheets. The interest rate swaps do not receive hedge accounting treatment under ASC 815 - Derivatives and Hedging. Changes in the fair value of the interest rate swaps are recorded in interest expense in the unaudited condensed consolidated statements of operations.

During the three months ended March 31, 2018, the weighted average interest rate under our credit agreement was 4.96%.

Changes in economic conditions could result in higher interest rates, thereby increasing our interest expense and reducing our funds available for capital investment, operations or distributions to our unitholders. Based on borrowings as of March 31, 2018, the terms of our credit agreement, current interest rates and the effect of our interest rate swaps, an increase or decrease of 100 basis points in the interest rate would result in increased or decreased annual interest expense of approximately $1.3 million.

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Item 4. Controls and Procedures.

Evaluation of disclosure controls and procedures. Our General Partner's management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, evaluated, as of the end of the period covered by this report, the effectiveness of our disclosure controls and procedures as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of our General Partner concluded that our disclosure controls and procedures, as of March 31, 2018, were not effective because of the material weakness in our internal control over financial reporting described in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A of Part II of our Annual Report on Form 10-K for the year ended December 31, 2017.

Remediation Plan for the Material Weakness. Our management is actively engaged in remediation efforts to address the material weakness identified. Specifically, our management is in the process of providing additional training of financial reporting personnel with respect to the preparation and review of the consolidated statements of cash flows with specific focus on the control that identifies non-cash components of transactions on the statement of cash flows. Our management believes that these actions will remediate the material weakness in internal control over financial reporting.

Changes in internal control over financial reporting. Except for the remediation efforts noted above, there were no changes in our internal control over financial reporting during the quarter ended March 31, 2018, which materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

The information required by this item is included under the caption "Commitments and Contingencies" in Note 15 to our unaudited condensed consolidated financial statements and is incorporated herein by reference thereto.

Item 1A. Risk Factors.

See the risk factors set forth in Part I, Item 1A, of our Annual Report on Form 10-K for the year ended December 31, 2017.

Item 6. Exhibits.

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report and is incorporated herein by reference.

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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.

		BLUEKNIGHT ENERGY PARTNERS, L.P.	
		By:	Blueknight Energy Partners, G.P., L.L.C its General Partner
Date:	May 10, 2018	By:	/s/ Alex G. Stallings Alex G. Stallings Chief Financial Officer and Secretary
Date:	May 10, 2018	By:	/s/ James R. Griffin James R. Griffin Chief Accounting Officer

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INDEX TO EXHIBITS

Exhibit Number	Description
3.1	Amended and Restated Certificate of Limited Partnership of the Partnership, dated November 19, 2009, but effective as of December 1, 2009 (filed as Exhibit 3.1 to the Partnership's Current Report on Form 8-K, filed November 25, 2009 (Commission File No. 001-33503), and incorporated herein by reference).
3.2	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated September 14, 2011 (filed as Exhibit 3.1 to the Partnership's Current Report on Form 8-K, filed September 14, 2011, and incorporated herein by reference).
3.3	Amended and Restated Certificate of Formation of the General Partner, dated November 20, 2009 but effective as of December 1, 2009 (filed as Exhibit 3.2 to the Partnership's Current Report on Form 8-K, filed November 25, 2009 (Commission File No. 001-33503), and incorporated herein by reference).
3.4	Second Amended and Restated Limited Liability Company Agreement of the General Partner, dated December 1, 2009 (filed as Exhibit 3.2 to the Partnership's Current Report on Form 8-K, filed December 7, 2009 (Commission File No. 001-33503), and incorporated herein by reference).
4.1	Registration Rights Agreement, dated October 5, 2016, by and among Blueknight Energy Partners, L.P., Ergon Asphalt & Emulsions, Inc., Ergon Terminaling, Inc. and Ergon Asphalt Holdings, LLC (filed as Exhibit 4.1 to the Partnership's Current Report on Form 8-K, filed October 5, 2016, and incorporated herein by reference).
31.1#	Certifications of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2#	Certifications of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1#	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. Pursuant to SEC Release 34-47551, this Exhibit is furnished to the SEC and shall not be deemed to be "filed."
101#	The following financial information from Blueknight Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, formatted in XBRL (eXtensible Business Reporting Language): (i) Document and Entity Information; (ii) Unaudited Condensed Consolidated Balance Sheets as of December 31, 2017 and March 31, 2018; (iii) Unaudited Condensed Consolidated Statements of Operations for the three months ended March 31, 2017 and 2018; (iv) Unaudited Condensed Consolidated Statement of Changes in Partners' Capital for the three months ended March 31, 2018; (v) Unaudited Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2017 and 2018; and (vi) Notes to Unaudited Condensed Consolidated Financial Statements.

\# Furnished herewith