Blueknight Energy Partners, L.P.
Form 10-Q
November 06, 2014

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

FORM 10-Q

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

For the quarterly period ended September 30, 2014

OR

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	20-8536826
(State or other jurisdiction of incorporation or organization)	(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 Q 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 Q No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

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

As of October 30, 2014, there were 30,158,619 Series A Preferred Units and 32,766,663 common units outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Unaudited Financial Statements

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

	As of December 31, 2013	As of September 30, 2014 (unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$3,182	$1,362
Accounts receivable, net of allowance for doubtful accounts of $69 and $222 at December 31, 2013 and September 30, 2014, respectively	12,244	12,803
Receivables from related parties, net of allowance for doubtful accounts of $0 and $171 at December 31, 2013 and September 30, 2014, respectively	3,149	3,118
Prepaid insurance	1,694	2,512
Assets held for sale, net of accumulated depreciation and impairments of $166 and $26 at December 31, 2013 and September 30, 2014, respectively	338	76
Other current assets	4,321	3,854
Total current assets	24,928	23,725
Property, plant and equipment, net of accumulated depreciation of $171,056 and $186,649 at December 31, 2013 and September 30, 2014, respectively	297,400	305,567
Investment in unconsolidated affiliate	19,498	19,975
Goodwill	7,216	7,216
Debt issuance costs, net	3,580	3,303
Intangibles and other assets, net	2,126	1,683
Total assets	$354,748	$361,469
LIABILITIES AND PARTNERS’ CAPITAL		
Current liabilities:		
Accounts payable	$6,537	$8,089
Accrued interest payable	482	175
Accrued property taxes payable	1,810	2,864
Unearned revenue	2,326	2,368
Unearned revenue with related parties	90	239
Accrued payroll	7,379	6,466
Other current liabilities	4,959	3,422
Total current liabilities	23,583	23,623
Unearned revenue with related parties, noncurrent	153	126
Other long-term liabilities	2,554	4,249
Interest rate swap liabilities	—	930
Long-term debt	273,000	212,000
Commitments and contingencies (Note 13)		
Partners’ capital:		
Series A Preferred Units (30,158,619 units issued and outstanding for both dates)	204,599	204,599
	461,149	526,302

Common unitholders (22,786,101 and 32,766,663 units issued and outstanding at December 31, 2013 and September 30, 2014, respectively)		
General partner interest (2.1% and 1.8% interest at December 31, 2013 and September 30, 2014, respectively, with 1,127,755 general partner units outstanding at both dates)	(610,290)	(610,360)
Total Partners' capital	55,458	120,541
Total liabilities and Partners' capital	$354,748	$361,469

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

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

	Three Months ended September 30,		Nine Months ended September 30,	
	2013	2014	2013	2014
	(unaudited)			
Service revenue:				
Third party revenue	$39,270	$38,501	$105,501	$107,935
Related party revenue	15,399	9,857	39,381	32,663
Total revenue	54,669	48,358	144,882	140,598
Expenses:				
Operating	32,132	32,295	95,440	102,272
General and administrative	4,649	4,267	13,806	13,124
Total expenses	36,781	36,562	109,246	115,396
Asset impairment expense	(123)	—	(123)	—
Gain on sale of assets	598	808	722	1,780
Operating income	18,363	12,604	36,235	26,982
Other income (expense):				
Equity earnings (loss) in unconsolidated affiliate	(151)	423	(325)	477
Interest expense (net of capitalized interest of $272, $84, $969, and $244, respectively)	(1,897)	(1,640)	(9,188)	(8,325)
Income from continuing operations before income taxes	16,315	11,387	26,722	19,134
Provision for income taxes	285	116	451	351
Income from continuing operations	16,030	11,271	26,271	18,783
Discontinued Operations:				
Loss from discontinued operations	(5,489)	—	(3,542)	—
Net income	$10,541	$11,271	$22,729	$18,783
Allocation of net income for calculation of earnings per unit:				
General partner interest in net income	$220	$247	$537	$437
Preferred interest in net income	$5,391	$5,391	$16,173	$16,173
Income available to limited partners	$4,930	$5,633	$6,019	$2,173
Basic net income from continuing operations per common unit	$0.44	$0.23	$0.41	$0.09
Basic net loss from discontinued operations per common unit	$(0.23)	$—	$(0.15)	$—
Basic net income per common unit	$0.21	$0.23	$0.26	$0.09
Diluted net income from continuing operations per common unit	$0.29	$0.20	$0.41	$0.09
Diluted net loss from discontinued operations per common unit	$(0.10)	$—	$(0.15)	$—
Diluted net income per common unit	$0.19	$0.20	$0.26	$0.09
Weighted average common units outstanding - basic	22,697	23,909	22,684	23,245
Weighted average common units outstanding - diluted	53,718	54,927	22,684	23,245

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

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

	Common Unitholders	Series A Preferred Unitholders	General Partner Interest	Total Partners' Capital
	(unaudited)			
Balance, December 31, 2013	$461,149	$204,599	$(610,290)	$55,458
Net income	2,237	16,173	373	18,783
Equity-based incentive compensation	831	—	17	848
Profits interest contribution	—	—	112	112
Proceeds from sale of 9,775,000 common units, net of underwriters' discount and offering expenses of $3.2 million	71,193	—	—	71,193
Distributions	(9,108)	(16,173)	(572)	(25,853)
Balance, September 30, 2014	$526,302	$204,599	$(610,360)	$120,541

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

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

	Nine Months ended September 30,	
	2013	2014
	(unaudited)	
Cash flows from operating activities:		
Net income	$22,729	$18,783
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for uncollectible receivables from third parties	400	153
Provision for uncollectible receivables from related parties	—	171
Depreciation and amortization	17,812	19,342
Amortization and write-off of debt issuance costs	3,117	603
Unrealized loss related to interest rate swaps	—	930
Asset impairment charge	5,855	—
Gain on sale of assets	(1,732)	(1,780)
Equity-based incentive compensation	1,547	848
Equity (earnings) loss in unconsolidated affiliate	325	(477)
Changes in assets and liabilities		
Increase in accounts receivable	(5,844)	(712)
Increase in receivables from related parties	(2,304)	(140)
Decrease in prepaid insurance	2,022	1,969
Decrease in other current assets	348	467
Decrease in other assets	11	128
Decrease in accounts payable	(1,490)	(503)
Decrease in accrued interest payable	(8)	(307)
Decrease in accrued interest payable to related parties	(304)	—
Increase in accrued property taxes	793	1,054
Increase (decrease) in unearned revenue	(388)	1,346
Increase (decrease) in unearned revenue from related parties	(97)	122
Increase (decrease) in accrued payroll	74	(913)
Decrease in other accrued liabilities	(605)	(1,765)
Net cash provided by operating activities	42,261	39,319
Cash flows from investing activities:		
Capital expenditures	(56,438)	(25,372)
Proceeds from sale of assets	1,980	1,982
Investment in unconsolidated affiliate	(20,000)	—
Net cash used in investing activities	(74,458)	(23,390)
Cash flows from financing activities:		
Payment on insurance premium financing agreement	(1,669)	(1,875)
Debt issuance costs	(3,639)	(326)
Payments on long-term payable to related party	(2,681)	—
Borrowings under credit facility	331,411	42,733
Payments under credit facility	(268,000)	(103,733)
Proceeds from equity issuance, net of offering costs	—	71,193
Capital contribution related to profits interest	112	112
Distributions	(24,872)	(25,853)
Net cash provided by (used in) financing activities	30,662	(17,749)
Net decrease in cash and cash equivalents	(1,535)	(1,820)

Cash and cash equivalents at beginning of period	3,177	3,182
Cash and cash equivalents at end of period	$1,642	$1,362
Supplemental disclosure of cash flow information:		
Increase in accounts payable related to purchase of property, plant and equipment	$3,465	$2,055
Increase in accounts receivable related to accrued proceeds on sale of assets	$(194)	$—
Increase in accrued liabilities related to insurance premium financing agreement	$2,609	$2,494
Decrease in accounts receivable related to purchase of property, plant and equipment	$1,274	$—

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

BLUEKNIGHT ENERGY PARTNERS, L.P.
NOTES TO UNAUDITED 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 twenty-two states. The Partnership provides integrated terminalling, storage, processing, gathering and transportation 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) crude oil terminalling and storage services, (ii) crude oil pipeline services, (iii) crude oil trucking and producer field services and (iv) asphalt 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 and practices generally accepted in the United States of America ("GAAP"). The consolidated statements of operations for the three and nine months ended September 30, 2013 and 2014, the consolidated statement of changes in partners' capital for the nine months ended September 30, 2014, the statement of cash flows for the nine months ended September 30, 2013 and 2014, and the consolidated balance sheet as of September 30, 2014 are unaudited. In the opinion of management, the unaudited 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 2013 year-end consolidated balance sheet data was derived from audited financial statements but does not include all disclosures required by GAAP. These 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, 2013 filed with the Securities and Exchange Commission (the "SEC") on March 12, 2014 (the "2013 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 4 of the Notes to Consolidated Financial Statements in its 2013 Form 10-K. A reclassification has been made to the consolidated statements of operations for the three and nine months ended September 30, 2013 to reflect a recasting of amounts related to discontinued operations (see Note 3). The reclassification has no impact on net income.

The Partnership's investment in Advantage Pipeline, L.L.C. ("Advantage Pipeline"), over which the Partnership has significant influence but not control, is accounted for by the equity method. The Partnership does 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 Consolidated Statements of Operations entitled "Equity earnings in unconsolidated affiliate" and will increase or decrease, as applicable, the carrying value of the Partnership's investment in the unconsolidated affiliate on the balance sheet. Distributions to the Partnership will reduce the carrying value of its investment and will be reflected in the Partnership's Consolidated Statements of Cash Flows in the line item "Distributions from unconsolidated affiliate." In turn, contributions will increase the carrying value of the Partnership's investment and will be reflected in the Partnership's Consolidated Statements of Cash Flows in investing activities. The Partnership evaluates its equity investment for impairment in accordance with FASB guidance with respect to the equity method of accounting for investments in common stock. An impairment of an equity investment results when factors indicate that the investment's fair value is less than its carrying value and the reduction in value is other than temporary in nature.

3. DISCONTINUED OPERATIONS

Northumberland, PA Asphalt Facility

On November 1, 2013, the Partnership entered into a litigation settlement in which title to its Northumberland, Pennsylvania asphalt facility was conveyed on November 21, 2013 to the counterparty to the settlement agreement in return for complete indemnification from any and all environmental liabilities or lawsuits related to the facility. The Partnership recognized a loss on the disposal of the facility of $0.6 million in 2013. The financial results of the Partnership's operations related to the Northumberland asphalt facility are reflected as discontinued operations in the consolidated statements of operations. All prior periods presented have been recast to reflect the discontinued operations.

The amounts of revenue and costs reported in discontinued operations are set forth in the table below for the period indicated:

	Three Months ended September 30, 2013	Nine Months ended September 30, 2013
	(in thousands, except per unit data)	
Total revenue	$164	$493
Expenses:		
Operating	49	105
Income from discontinued operations	$115	$388
Basic net income from discontinued operations per common unit	$0.01	$0.02
Diluted net income from discontinued operations per common unit	$—	$0.02

The following table discloses the major classes of discontinued assets and liabilities related to the Northumberland asphalt facility at the disposal date:

	November 21, 2013
	(in thousands)
Assets	
Accounts Receivable	$4
Assets of discontinued operations	$4
Liabilities	
Accounts Payable	$13
Deferred Revenue	28
Other liabilities	84
Liabilities of discontinued operations	$125

Thompson to Webster Pipeline System

In September 2013, the Partnership experienced an oil spill on its Thompson to Webster Pipeline System. As the costs associated with future maintenance of the pipeline and the potential future realizable cash flows from this pipeline were assessed, the Partnership determined that it was not economically feasible for it to continue to operate the pipeline. The Partnership assessed the recoverability of the carrying value of this asset and determined it was impaired. This resulted in $5.7 million of impairment expense being recorded in 2013, which reduced the carrying value of this pipeline to the discounted future net cash flows the Partnership expected to realize from this asset. During the discussions with the current shipper on necessary future maintenance and the possibility of idling the system, the shipper expressed interest in purchasing the system. On December 30, 2013, the sale to the shipper was finalized. The financial information of the Thompson to Webster Pipeline System is reflected as discontinued operations in the consolidated statements of operations. All prior periods presented have been recast to reflect the discontinued operations.

The amounts of revenue and costs reported in discontinued operations are set forth in the table below for the period indicated:

	Three Months ended September 30 2013	Nine Months ended September 30, 2013
	(in thousands, except per unit data)	
Total revenue	$410	$1,750
Expenses:		
Operating	418	958
Asset impairment expense	5,732	5,732
Gain on sale of assets	136	1,010
Loss from discontinued operations	$(5,604)	$(3,930)
Basic net loss from discontinued operations per common unit	$(0.24)	$(0.17)
Diluted net loss from discontinued operations per common unit	$(0.10)	$(0.17)

The following table discloses the major classes of discontinued assets and liabilities related to the Thompson to Webster Pipeline System at the disposal date:

	December 30, 2013
	(in thousands)
Assets	
Accounts Receivable	$400
Property, plant and equipment, net	1,000
Assets of discontinued operations	$1,400
Liabilities	
Accounts Payable	$1
Deferred Revenue	148
Other liabilities	339
Liabilities of discontinued operations	$488

4. PROPERTY, PLANT AND EQUIPMENT

	Estimated Useful Lives (Years)	December 31, 2013	September 30, 2014
		(dollars in thousands)	
Land	N/A	$16,374	$17,680
Land improvements	10-20	6,306	6,351
Pipelines and facilities	5-30	144,261	159,176
Storage and terminal facilities	10-35	234,208	238,592
Transportation equipment	3-10	16,735	14,241
Office property and equipment and other	3-20	26,371	28,182
Pipeline linefill and tank bottoms	N/A	10,193	10,186
Construction-in-progress	N/A	14,008	17,808
Property, plant and equipment, gross		468,456	492,216
Accumulated depreciation		(171,056)	(186,649)
Property, plant and equipment, net		$297,400	$305,567

Depreciation expense for the three months ended September 30, 2013 and 2014 was $6.1 million and $6.6 million, respectively, and depreciation expense for the nine months ended September 30, 2013 and 2014 was $17.8 million and $19.3

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million, respectively. In the three and nine months ended September 30, 2013 , the Partnership recorded asset impairment expense of $5.9 million related to its pipelines and facilities, 5.7 million of which relates to the Thompson to Webster Pipeline System located in southern Texas. The Thompson to Webster Pipeline System was sold in December 2013 and is reflected as discontinued operations (see Note 3).

5. DEBT

On June 28, 2013, the Partnership entered into an amended and restated credit agreement which consists of a $400.0 million revolving loan facility. On September 15, 2014, the Partnership amended its credit facility to, among other things, amend the maximum permitted consolidated total leverage ratio as discussed below and to increase the limit on material project adjustments to EBITDA (as defined in the credit agreement).

As of October 30, 2014, approximately $212.0 million of revolver borrowings and $0.7 million of letters of credit were outstanding under the credit facility, leaving the Partnership with approximately $187.3 million available capacity for additional revolver borrowings and letters of credit under the credit facility, although the Partnership's ability to borrow such funds may be limited by the financial covenants in the credit facility. In connection with entering into the amended and restated credit agreement and the amendment thereto, the Partnership paid certain fees to the lenders thereunder, and the Partnership paid certain arrangement and other fees to the arranger and administrative agent of the credit agreement. The proceeds of loans made under the amended and restated credit agreement may be used for working capital and other general corporate purposes of the Partnership. All references herein to the credit agreement on or after June 28, 2013 refer to the amended and restated credit agreement, as amended on September 15, 2014.

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, including all material pipeline, gathering and processing assets, all material storage tanks and asphalt facilities, all material working capital assets and a pledge of all of the Partnership's equity interests in its subsidiaries.

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 $500.0 million for all revolving loan commitments under the credit agreement.

The credit agreement will mature on June 28, 2018, and all amounts outstanding under the credit agreement will become due and payable on such date. The Partnership may prepay all loans under the credit agreement at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. 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%) plus 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 credit agreement does not have a floor for the alternate base rate or the eurodollar rate. 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 4.50 to 1.00; provided that:

- after the Partnership delivers the Knight Warrior Pipeline Initiation Certificate (as defined in the credit agreement, but generally meaning that the Partnership has spent at least $15.0 million of the projected capital expenditures for its Knight Warrior pipeline project), the maximum permitted consolidated total leverage ratio is 5.00 to 1.00 for the fiscal quarters ending March 31, 2015 through September 30, 2016, 4.75 to 1.00 for the fiscal quarter ending December 31, 2016, and 4.50 to 1.00 for each fiscal quarter thereafter;

- after the Partnership delivers the Knight Warrior Pipeline Leverage Election Certificate (as defined in the credit agreement, but generally meaning that the Partnership has spent at least 50% of the projected capital expenditures for the Knight Warrior pipeline project), the Partnership may elect to increase the maximum permitted consolidated total leverage ratio to 5.50 to 1.00 for two consecutive fiscal quarters ending on or before September 30, 2016; and
- if the Partnership makes a specified acquisition (as defined in the credit agreement, but generally being an acquisition with consideration in excess of $15.0 million), the Partnership may elect to increase the maximum permitted consolidated total leverage ratio to 5.00 to 1.00 from and after the last day of the fiscal quarter immediately preceding the fiscal quarter in which such acquisition occurs to and including the last day of the second full fiscal quarter following the fiscal quarter in which such acquisition occurred.

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 after the Partnership delivers the Knight Warrior Pipeline Initiation Certificate, the maximum permitted consolidated total leverage ratio is 5.50 to 1.00 for the fiscal quarters ending March 31, 2015 through September 30, 2016, and 5.00 to 1.00 for each fiscal quarter thereafter.

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;
- enter into operating leases; and
- make certain amendments to the Partnership’s partnership agreement.

At September 30, 2014, the Partnership’s consolidated total leverage ratio was 3.18 to 1.00 and the consolidated interest coverage ratio was 7.12 to 1.00. The Partnership was in compliance with all covenants of its credit agreement as of September 30, 2014.

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 7 for additional information regarding distributions.

Each of the following is an event of default under the credit agreement:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;
- failure to observe any other agreement, obligation or covenant in the credit agreement or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- the Partnership's, or any of its restricted subsidiaries', default under other indebtedness that exceeds a threshold amount;
- judgments against the Partnership or any of its restricted subsidiaries, in excess of a threshold amount;
- certain ERISA events involving the Partnership or its restricted subsidiaries resulting in a material adverse effect on the Partnership;
- bankruptcy or other insolvency events involving the General Partner, the Partnership or any of its restricted subsidiaries; and
- a change of control (as defined in the credit agreement, but generally being (i) the General Partner ceasing to own 100% of the Partnership's general partner interest or ceasing to control the Partnership or (ii) Vitol Holding B.V. (together with its affiliates, "Vitol") and Charlesbank Capital Partners, LLC ceasing to collectively own and control 50.0% or more of the membership interests of the General Partner).

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 have letters of credit issued under the credit agreement.

Upon the execution of the amended and restated credit agreement on June 28, 2013, the Partnership expensed $1.8 million of debt issuance costs related to the extinguished term loan and $0.2 million in debt issuance costs related to its revolving loan facility, leaving a remaining balance of $0.5 million ascribed to those lenders with commitments under both the prior and the amended and restated credit facility. During the nine months ended September 30, 2013, the Partnership capitalized debt issuance costs of $0.2 million related to the prior credit facility. During the three months ended September 30, 2013 and 2014, the Partnership capitalized debt issuance costs of $0.3 million related to the current credit facility for both periods. During the nine months ended September 30, 2013 and 2014, the Partnership capitalized debt issuance costs of $3.4 million and $0.3 million related to the current credit facility, respectively. The debt issuance costs are being amortized over the term of the amended and restated credit agreement. Interest expense related to debt issuance cost amortization for each of the three months ended September 30, 2013 and 2014 was $0.2 million. Interest expense related to debt issuance cost amortization for the nine months ended September 30, 2013 and 2014 was $1.1 million and $0.6 million, respectively, excluding the $1.8 million of debt issuance costs related to the extinguished term loan and $0.2 million in debt issuance costs related to the revolving loan facility that were expensed upon the execution of the amended and restated credit agreement in June of 2013.

During the three months ended September 30, 2013 and 2014, the weighted average interest rate under the Partnership's credit agreement was 3.18% and 3.41%, respectively, resulting in interest expense of approximately $2.2 million and $2.5 million, respectively. During the nine months ended September 30, 2013 and 2014, the weighted average interest rate under the Partnership's credit agreement, excluding the $2.0 million of debt issuance costs related to the prior credit facility that was expensed in the nine months ended September 30, 2013, was 4.39% and 3.41%, respectively, resulting in interest expense of approximately $8.2 million and $7.3 million, respectively. As of September 30, 2014, borrowings under the Partnership's amended and restated credit agreement bore interest at a weighted average interest rate of 3.72%.

During the three months ended September 30, 2013 and 2014, the Partnership capitalized interest of $0.3 million and $0.1 million, respectively. During the nine months ended September 30, 2013 and 2014, the Partnership capitalized interest of $1.0 million and $0.2 million, respectively.

The Partnership is exposed to market risk for changes in interest rates related to its credit facility. 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 the Partnership entered into two interest rate swap agreements with an aggregate notional amount of $200.0 million. The first agreement has a notional amount of $100.0 million, became effective June 28, 2014, and matures on June 28, 2018. Under the terms of the first interest rate swap agreement, the Partnership pays a fixed rate of 1.45% and receives one-month LIBOR with monthly settlement. The second agreement has a notional amount of $100.0 million, becomes effective January 28, 2015, and matures on January 28, 2019. Under the terms of the second interest rate swap agreement, the Partnership will pay a fixed rate of 1.97% and will receive one-month LIBOR with monthly settlement. During each of the three and nine months ended September 30, 2014, the Partnership recorded swap interest expense of $0.3 million. The fair market value of the interest rate swaps at September 30, 2014 is a liability of $0.9 million and is recorded in long-term derivative liabilities on the consolidated balance sheet. 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 statements of operations.

6. 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 entities' 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 September 30,		Nine Months ended September 30,	
	2013	2014	2013	2014
Net income from continuing operations	$16,030	$11,271	$26,271	$18,783
Loss from discontinued operations	(5,489)	—	(3,542)	—
Net income	10,541	11,271	22,729	18,783
General partner interest in net income	220	247	537	437
Preferred interest in net income	5,391	5,391	16,173	16,173
Income available to limited partners	$4,930	$5,633	$6,019	$2,173
Basic weighted average number of units:				
Common units	22,697	23,909	22,684	23,245
Restricted and phantom units	699	725	667	659
Diluted weighted average number of units:				
Common units	53,718	54,927	22,684	23,245
Basic net income from continuing operations per common unit	$0.44	$0.23	$0.41	$0.09
Basic net loss from discontinued operations per common unit	$(0.23)	$—	$(0.15)	$—
Basic net income per common unit	$0.21	$0.23	$0.26	$0.09
Diluted income from continuing operations per common unit	$0.29	$0.20	$0.41	$0.09
Diluted loss from discontinued operations per common unit	$(0.10)	$—	$(0.15)	$—
Diluted net income per common unit	$0.19	$0.20	$0.26	$0.09

7. PARTNERS' CAPITAL AND DISTRIBUTIONS

On September 22, 2014, the Partnership issued and sold 9,775,000 common units for a public offering price of $7.61, resulting in proceeds of approximately $71.2 million, net of underwriters' discount and offering expenses of $3.2 million.

On October 23, 2014, the Board approved a distribution of $0.17875 per Preferred Unit, or a total distribution of $5.4 million, for the quarter ending September 30, 2014. The Partnership will pay this distribution on the preferred units on November 14, 2014 to unitholders of record as of November 4, 2014.

In addition, on October 23, 2014, the Board declared a cash distribution of $0.1345 per unit on its outstanding common units, a 1.5% increase over the previous quarter's distribution. The distribution will be paid on November 14, 2014 to unitholders of record on November 4, 2014. The distribution is for the three months ended September 30, 2014. The total distribution will be approximately $4.7 million, with approximately $4.4 million and $0.2 million to be paid to the Partnership's common unitholders and general partner, respectively, and $0.1 million to be paid to holders of phantom and restricted units pursuant to awards granted under the Partnership's long-term incentive plan.

8. RELATED PARTY TRANSACTIONS

The Partnership provides crude oil gathering, transportation, terminalling and storage services to Vitol as well as certain operating, strategic assessment, economic evaluation and project design services. For the three months ended September 30, 2013 and 2014, the Partnership recognized revenues of $15.1 million and $9.6 million, respectively, for services provided to Vitol. For the nine months ended September 30, 2013 and 2014, the Partnership recognized revenues of $39.0 million and $31.9 million, respectively, for services provided to Vitol. As of both December 31, 2013 and September 30, 2014, the Partnership had receivables from Vitol of $3.0 million, net of allowance for doubtful accounts. As of December 31, 2013 and September 30, 2014, the Partnership had unearned revenues from Vitol of $0.2 million and $0.3 million, respectively.

The Partnership also provides operating and administrative services to Advantage Pipeline. For the each of the three months ended September 30, 2013 and 2014, the Partnership earned revenues of $0.3 million for services provided to Advantage Pipeline. For the nine months ended September 30, 2013 and 2014, the Partnership earned revenues of $0.3 million and $0.7 million, respectively, for services provided to Advantage Pipeline. As of December 31, 2013 and September 30, 2014, the Partnership had receivables from Advantage Pipeline of $0.2 million and $0.1 million, respectively.

9. LONG-TERM INCENTIVE PLAN

In July 2007, the General Partner adopted the Long-Term Incentive Plan (the "LTIP"). The compensation committee of the Board administers the LTIP. 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 by 1,500,000 common units from 2,600,000 common units to 4,100,000 common units. The common units are deliverable upon vesting. 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. Certain of 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 units are entitled to receive cash distributions paid on common units during the vesting period which distributions 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 each of December 2011, 2012 and 2013, 7,500 restricted common units were granted which vest in one-third increments over three years. These grants were made in connection with the anniversary of the independent directors joining the Board. The fair value of the restricted units for the 2011 and 2012 grants was less than $0.1 million while the fair value of the restricted units for the 2013 grant was $0.1 million.

In March 2012, 2013 and 2014, grants for 353,300, 251,106 and 276,773 phantom units, respectively, were made, which vest on January 1, 2015, January 1, 2016 and January 1, 2017, respectively. 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 weighted average grant date fair-value of the awards is \$6.76, \$8.75 and \$9.06 per unit, respectively, which is the closing market price on the grant date of the awards. The value of these award grants was approximately \$2.4 million, \$2.2 million and \$2.5 million, respectively, on their grant date. The unrecognized estimated compensation cost of outstanding phantom units at September 30, 2014 was \$2.4 million, which will be recognized over the remaining vesting period.

In September 2012, Mark Hurley was granted 500,000 phantom units under the LTIP upon his employment as the Chief Executive Officer of the General Partner. 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. These units vest ratably over five years pursuant to the Employee Phantom Unit Agreement between Mr. Hurley and the General Partner and do not include DERs. The weighted average grant date fair value for the units of \$5.62 was determined based on the closing market price of the Partnership's common units on the grant date of the award, less the present value of the estimated distributions to be paid to holders of an outstanding common unit prior to the vesting of the underlying award. The value of this award grant was approximately $2.8 million on the grant date, and the unrecognized estimated compensation cost at September 30, 2014 was $1.7 million and will be expensed over the remaining vesting period.

The Partnership's equity-based incentive compensation expense for the three months ended September 30, 2013 and 2014 was $0.5 million and $0.6 million, respectively. The Partnership's equity-based incentive compensation expense for the nine months ended September 30, 2013 and 2014 was $1.5 million and $1.6 million, respectively.

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

	Number of Units	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2013	1,058,162	$7.03
Granted	276,773	9.06
Vested	298,936	7.36
Forfeited	11,304	8.34
Nonvested at September 30, 2014	1,024,695	$7.47

10. EMPLOYEE BENEFIT PLAN

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 and $0.4 million for the three months ended September 30, 2013 and 2014 for discretionary contributions under the 401(k) Plan. The Partnership recognized expense of $1.0 million and $1.1 million for the nine months ended September 30, 2013 and 2014 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 for both the three months ended September 30, 2013 and 2014, for discretionary profit sharing contributions under the 401(k) Plan. The Partnership recognized expense of $0.8 million and $0.5 million for the nine months ended September 30, 2013 and 2014, respectively, for discretionary profit sharing contributions under the 401(k) Plan.

11. FAIR VALUE MEASUREMENTS

The Partnership utilizes a three-tier framework for assets and liabilities required to be measured at fair value. In addition, 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 these assets and liabilities 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. 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 September 30, 2014			
Description	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities:				
Interest rate swap liabilities	$930	$—	$930	$—
Total	$930	$—	$930	$—

The Partnership had no recurring financial assets or liabilities subject to fair value measurements as of December 31, 2013.

The following table sets forth a reconciliation of changes in the fair value of the Partnership's financial liabilities classified as Level 3 in the fair value hierarchy (in thousands):

	Measurements Using Significant Unobservable Inputs (Level 3)	
	Three Months ended September 30, 2014	Nine Months ended September 30, 2014
Beginning Balance	$2,002	$—
Total gains or losses (realized/unrealized):		
Included in earnings[(1)]	1,072	(930)
Included in other comprehensive income	—	—
Purchases, issuances, and settlements	—	—
Transfers in and/or out of Level 3	930	930
Ending Balance	$—	$—
The amount of total income (expense) for the period included in earnings attributable to the change in unrealized gains (losses) for liabilities still held at the reporting date	$1,072	$(930)

(1) Amounts reported as included in earnings are reported as interest expense on the statements of operations.

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 September 30, 2014, the carrying values on the 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 September 30, 2014 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.

12. OPERATING SEGMENTS

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

CRUDE OIL TERMINALLING AND STORAGE SERVICES —The Partnership provides crude oil terminalling and storage services at its terminalling and storage facilities located in Oklahoma and Texas.

CRUDE OIL PIPELINE SERVICES —The Partnership owns and operates three pipeline systems, the Mid-Continent system, the Longview system and the Eagle North System, 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 and storage 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 system. It refers to its second pipeline system, which is located in Texas, as the Longview system. The Partnership refers to its third system, originating in Cushing, Oklahoma and terminating in Ardmore, Oklahoma, as the Eagle North system.

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.

ASPHALT SERVICES —The Partnership provides asphalt product and residual fuel terminalling, storage and blending services at its 42 terminalling and storage facilities located in twenty-one states.

The Partnership's management evaluates performance based upon segment operating margin, which includes revenues from related parties and external customers and operating expenses excluding depreciation and amortization. The non-GAAP measure of operating margin (in the aggregate and by segment) is presented in the following table. The Partnership computes the components of operating margin by using amounts that are determined in accordance with GAAP. A reconciliation of operating margin 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 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 September 30,		Nine Months ended September 30,	
	2013	2014	2013	2014
Crude Oil Terminalling and Storage Services				
Service revenue				
Third party revenue	$3,216	$1,875	$9,149	$7,020
Related party revenue	4,477	3,080	14,495	10,726
Total revenue for reportable segments	7,693	4,955	23,644	17,746
Operating expenses (excluding depreciation and amortization)	1,068	1,006	2,872	2,980
Operating margin (excluding depreciation and amortization)	6,625	3,949	20,772	14,766
Total assets (end of period)	$65,314	$67,451	$65,314	$67,451
Crude Oil Pipeline Services				
Service revenue				
Third party revenue	$6,499	$5,906	$12,681	$13,439
Related party revenue	4,807	2,098	7,179	5,934
Total revenue for reportable segments	11,306	8,004	19,860	19,373
Operating expenses (excluding depreciation and amortization)	3,968	2,484	11,056	11,600
Operating margin (excluding depreciation and amortization)	7,338	5,520	8,804	7,773
Total assets (end of period)	$175,476	$170,700	$175,476	$170,700
Crude Oil Trucking and Producer Field Services				
Service revenue				
Third party revenue	$11,712	$12,264	$36,085	$38,280
Related party revenue	5,805	4,433	16,370	15,057
Total revenue for reportable segments	17,517	16,697	52,455	53,337
Operating expenses (excluding depreciation and amortization)	15,226	15,607	45,469	48,235
Operating margin (excluding depreciation and amortization)	2,291	1,090	6,986	5,102
Total assets (end of period)	$20,446	$28,208	$20,446	$28,208
Asphalt Services				
Service revenue				
Third party revenue	$17,843	$18,456	$47,586	$49,196
Related party revenue	310	246	1,337	946
Total revenue for reportable segments	18,153	18,702	48,923	50,142
Operating expenses (excluding depreciation and amortization)	5,895	6,627	18,510	20,115
Operating margin (excluding depreciation and amortization)	12,258	12,075	30,413	30,027
Total assets (end of period)	$101,215	$95,110	$101,215	$95,110
Total operating margin (excluding depreciation and amortization)(1)	$28,512	$22,634	$66,975	$57,668

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

	Three Months ended September 30,		Nine Months ended September 30,	
	2013	2014	2013	2014
Operating margin (excluding depreciation and amortization) from continuing operations	$28,512	$22,634	$66,975	$57,668
Depreciation and amortization on continuing operations	(5,975)	(6,571)	(17,533)	(19,342)
General and administrative expenses	(4,649)	(4,267)	(13,806)	(13,124)
Asset impairment expense	(123)	—	(123)	—
Gain on sale of assets	598	808	722	1,780
Interest expense	(1,897)	(1,640)	(9,188)	(8,325)
Equity gain (loss) in unconsolidated entity	(151)	423	(325)	477
Income from continuing operations before income taxes	$16,315	$11,387	$26,722	$19,134

13. 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.

On October 27, 2008, Keystone Gas Company (“Keystone”) filed suit against the Partnership in Oklahoma State District Court in Creek County alleging that it is the rightful owner of certain segments of the Partnership’s pipelines and related rights of way, located in Payne and Creek Counties, that the Partnership acquired from SemGroup Corporation (together with its predecessors including SemGroup, L.P., subsidiaries and affiliates referred to herein as “SemCorp”) in connection with the Partnership’s initial public offering in 2007. Keystone seeks to quiet title to the specified rights of way and pipelines and seeks damages related to the disputed pipelines. The Partnership has filed a counterclaim against Keystone alleging that it is wrongfully using a segment of a pipeline that is owned by the Partnership in Payne and Creek Counties. The Partnership intends to vigorously defend these claims. No trial date has been set by the court. The parties are engaged in discovery and continuing settlement negotiations. The Partnership believes that any settlement will not have a material adverse effect on the Partnership’s financial condition or results of operations.

On February 6, 2012, the Partnership filed suit against SemCorp and others in Oklahoma County District Court. In the suit, the Partnership is seeking a judgment that SemCorp immediately return approximately 140,000 barrels of crude oil linefill belonging to the Partnership, and the Partnership is seeking judgment in an amount in excess of $75,000 for actual damages, special damages, punitive damages, pre-judgment interest, reasonable attorney’s fees and costs, and such other relief that the Court deems equitable and just. On March 22, 2012, SemCorp filed a motion to dismiss and transfer to Tulsa County. On April 18, 2012, SemCorp filed a motion for summary judgment, and, on May 1, 2012, the District Court of Oklahoma County ordered a transfer to Tulsa County. The Partnership contested SemCorp’s motion for summary judgment, which was referred to a Special Master for report and recommendation. On June 10, 2013, the Special Master filed a report with the District Court of Tulsa County, finding a shortage in the Partnership’s Cushing Terminal and Oklahoma pipeline system of approximately 148,000 barrels and an excess of approximately 130,000 in SemCorp’s physical inventory. The Special Master noted that she was unable to more precisely trace the shortage and length (excess held by SemCorp) due to the manner in which SemCorp operated the Cushing Terminal and maintained related records. On June 25, 2013, the Partnership filed a notice of non-objection and motion to adopt the Special Master’s report, which was granted on February 12, 2014. On September 17, 2013, the Partnership filed a motion for summary judgment as to the liability of SemCorp for the Partnership's claims for breach of contract and negligence by a bailee. On October 7, 2013, SemCorp renewed its motion for summary judgment, which the Partnership timely opposed. On February 20, 2014, the Court denied summary judgment motions of both SemCorp and the Partnership. The Court allowed for additional discovery to take place and referred all discovery matters to the Special Master, as appropriate, and made other procedural rulings. The Partnership reasserted its fraud claims in accordance with the Court's directives. Discovery proceedings continue and the Partnership has determined that SemCorp knew of its excess inventory and sold this inventory during the period prior to the Partnership's filing of the lawsuit while denying that the Partnership claims had any validity and failing to disclose the excess to the Partnership. The Partnership intends to seek additional damages from SemCorp related to various injuries to the Partnership as a result of SemCorp's refusal to return the Partnership's crude oil or to pay the Partnership for the fair market value of the missing oil.

In late November 2013, one of the Partnership's pipelines in East Texas leaked approximately 500 barrels of oil. The response and clean-up cost is expected to total approximately $2.1 million, all of which is reflected in the Partnership's 2013 results of operations. The Partnership made a claim against its pollution liability insurance provider (Aspen) to cover the expenses related to the spill and has paid its deductible of $250,000. In early February 2014, Aspen filed a lawsuit against the Partnership to rescind the policy. In September 2014, this matter was settled on terms reasonable to both parties.

The Partnership may become the subject of additional private or government actions regarding these matters in the future. Litigation may be time-consuming, expensive and disruptive to normal business operations, and the outcome of litigation is difficult to predict. The defense of these lawsuits may result in the incurrence of significant legal expense, both directly and as the result of the Partnership's indemnification obligations. The litigation may also divert management's attention from the Partnership's operations which may cause its business to suffer. An unfavorable outcome in any of these matters may have a material adverse effect on the Partnership's business, financial condition, results of operations, cash flows, ability to make distributions to its unitholders, the trading price of the Partnership's common units and its ability to conduct its business. All or a portion of the defense costs and any amount the Partnership may be required to pay to satisfy a judgment or settlement of these claims may or may not be covered by insurance.

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 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.

14. INCOME TAXES

The anticipated after-tax economic benefit of an investment in the Partnership's units depends largely on the Partnership being treated as a partnership for federal income tax purposes. If less than 90% of the gross income of a publicly traded partnership, such as the Partnership, for any taxable year is "qualifying income" from sources such as the transportation, marketing (other than to end users), or processing of crude oil, natural gas or products thereof, interest, dividends or similar sources, that partnership will be taxable as a corporation under Section 7704 of the Internal Revenue Code for federal income tax purposes for that taxable year and all subsequent years.

If the Partnership were treated as a corporation for federal income tax purposes, then it would pay federal income tax on its income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions would generally be taxed again to unitholders as corporate distributions and none of the Partnership's income, gains, losses, deductions or credits would flow through to its unitholders. Because a tax would be imposed upon the Partnership as an entity, cash available for distribution to its unitholders would be substantially reduced. Treatment of the Partnership as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to unitholders and thus would likely result in a substantial reduction in the value of the

Partnership’s units.

The Partnership has entered into storage contracts and leases with third party customers with respect to substantially all of its asphalt facilities. At the time of entering into such agreements, it was unclear under current tax law as to whether the rental income from the leases, and the fees attributable to certain of the processing services the Partnership provides under certain of the storage contracts, constitute “qualifying income.” In the second quarter of 2009, the Partnership submitted a request for a ruling from the IRS that rental income from the leases constitutes “qualifying income.” In October 2009, the Partnership received a favorable ruling from the IRS. As part of this ruling, however, the Partnership agreed to transfer, and has transferred, certain of its asphalt processing assets and related fee income to a subsidiary taxed as a corporation. This transfer occurred in the first quarter of 2010. Such subsidiary is required to pay federal income tax on its income at the corporate tax rate, which is currently a maximum of 35%, and will likely pay state (and possibly local) income tax at varying rates. Distributions from this subsidiary will generally be taxed again to unitholders as corporate distributions and none of the income, gains, losses, deductions or credits of this subsidiary will flow through to the Partnership’s unitholders.

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 September 30, 2014 are presented below (dollars in thousands):

Deferred tax assets	
Difference in bases of property, plant and equipment	$950
Deferred tax asset	950
Less: valuation allowance	(950)
Net deferred tax asset	$—

Given that the Partnership's subsidiary that is taxed as a corporation has a limited earnings history for purposes of determining the likelihood of realizing the benefits of the deferred tax assets, the Partnership has provided a full valuation allowance against its deferred tax asset.

15. RECENTLY ISSUED ACCOUNTING STANDARDS

In July 2013, the FASB issued ASU 2013-11, "Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists." The amendment provides explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The amendments in this update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The Partnership adopted this update in January 2014, and the impact was not material.

In April 2014, the FASB issued ASU 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." The amendments in this update change the criteria for reporting discontinued operations for all public and nonpublic entities. The amendments also require new disclosures about discontinued operations and disposals of components of an entity that do not qualify for discontinued operations reporting. The amendments in this update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2014. The Partnership is evaluating the impact of this guidance, which will be adopted beginning with the Partnership's quarterly report for the period ending March 31, 2015.

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. The amendments in this update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Partnership is evaluating the impact of this guidance, which will be adopted beginning with the Partnership's quarterly report for the period ending March 31, 2017.

In August 2014, the FASB issued ASU 2014-15, "Presentation of Financial Statements - Going Concern." The Update provides U.S. GAAP guidance on management's responsibility in evaluating whether there is substantial doubt about a company's ability to continue as a going concern and about related footnote disclosures. For each reporting period, management will be required to evaluate whether there are conditions or events that raise substantial doubt about a company's ability to continue as a going concern within one year from the date the financial statements are issued. The amendments in this update are effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. The Partnership is evaluating the impact of this guidance, which will be adopted beginning with the Partnership's annual report for the period ending December 31, 2016.

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) Vitol refers to Vitol Holding B.V., its affiliates and subsidiaries (other than our General Partner and us) and (4) Charlesbank refers to Charlesbank Capital Partners, LLC, its affiliates and subsidiaries (other than our General Partner and us). 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, 2013, which was filed with the Securities and Exchange Commission (the "SEC") on March 12, 2014 (the "2013 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 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 2013 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 twenty-two states. We provide integrated terminalling, storage, gathering and transportation services for companies engaged in the production, distribution and marketing of crude oil and liquid asphalt cement. We manage our operations through four operating segments: (i) crude oil terminalling and storage services, (ii) crude oil pipeline services, (iii) crude oil trucking and producer field services, and (iv) asphalt services.

Recent Events

On August 6, 2014, we announced our plans to build a 160-mile, 16-inch diameter pipeline linking the emerging East Texas Eaglebine/Woodbine crude oil resource play to a crude oil and product terminal on the Houston Ship Channel owned and operated by Oiltanking Partners, L.P. The pipeline, which we refer to as the Knight Warrior pipeline, will have an initial capacity of 100,000 barrels per day and will be expandable up to 200,000 barrels per day. The pipeline will have the capacity to segregate and batch crude oil in order to help producers capture value for this premium product.

On September 22, 2014, we issued and sold 9,775,000 common units for a public offering price of $7.61, resulting in proceeds of approximately $71.2 million, net of underwriters' discount and offering expenses of $3.2 million. We intend to use the net proceeds from the offering for general partnership purposes, including the repayment of a portion of the outstanding borrowings under our credit facility and partially funding the Knight Warrior pipeline project.

Our Revenues

Our revenues consist of (i) terminalling and storage revenues, (ii) gathering, transportation and producer field services revenues and (iii) fuel surcharge revenues. For the nine months ended September 30, 2014, we derived approximately $31.9 million and $0.7 million of our revenues from services we provided to Vitol and Advantage Pipeline L.L.C. (“Advantage Pipeline”), respectively, with the remainder of our services being provided to third parties.

Terminalling and storage revenues consist of (i) storage service fees from actual storage used on a month-to-month basis; (ii) 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 (iii) terminal throughput service charges to pump crude oil to connecting carriers or to deliver asphalt product out of our terminals. Terminal throughput service charges are recognized as the crude oil exits the terminal and is delivered to the connecting crude oil carrier or third-party terminal and as the asphalt product is delivered out of our terminal. Storage service revenues are recognized as the services are provided on a monthly basis. We earn terminalling and storage revenues in two of our segments: (i) crude oil terminalling and storage services and (ii) asphalt services.

As of October 30, 2014, we had approximately 5.0 million barrels of crude oil storage under service contracts with remaining terms ranging from two months to 24 months, including 0.7 million barrels of crude oil storage contracts that expire by the end of 2014. We are in negotiations to either extend contracts with existing customers or enter into new customer contracts for the storage capacity; 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.

There are a number of market dynamics currently taking place at the Cushing Interchange, including a backwardated market for West Texas Intermediate crude oil, increased Cushing storage capacity, additional pipeline capacity for delivery out of the Cushing Interchange and significant production increases in Kansas, Oklahoma and Texas. These trends are negatively impacting demand for crude oil storage and putting downward pressure on storage rates. The current market environment places more importance on services and connectivity and, as a result, we plan to invest approximately $8.0 million in capital projects in Cushing in 2014 to enhance our connectivity and crude oil blending services, of which $5.5 million has been spent as of September 30, 2014. We believe our mix and delivery of services will differentiate us from competitors and attract new customers.

We have leases and storage agreements with third party customers for all of our 42 asphalt facilities. The majority of the leases and storage agreements related to these facilities have terms that expire between the end of 2016 and the end of 2018. We operate the asphalt facilities pursuant to the storage agreements while our contract counterparties operate the asphalt facilities that are subject to the lease agreements.

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 and storage facilities owned by us and others. 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. 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.

During the three months ended September 30, 2014, we transported approximately 51,100 barrels per day on our pipelines as compared to 52,000 barrels per day during the three months ended September 30, 2013. Vitol accounted for 27% and 30% of volumes transported in our pipelines in the three months ended September 30, 2014 and 2013, respectively.

For the three months ended September 30, 2014, we transported approximately 61,100 barrels per day on our crude oil transport trucks, a decrease of 2% as compared to the three months ended September 30, 2013. Vitol accounted for approximately 39% and 48% of volumes transported by our crude oil transport trucks in the three months ended September 30, 2014 and 2013, respectively.

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

Income Taxes

As part of the process of preparing the 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 consolidated balance sheet. 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. If we believe that recovery is not likely, 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 consolidated statement 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.

Given that our subsidiary that is taxed as a corporation has a limited earnings history for purposes of determining the likelihood of realizing the benefits of the deferred tax assets, we have provided a full valuation allowance against our deferred tax asset as of September 30, 2014.

Distributions

The amount of distributions we pay and the decision to make any distribution is determined by 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 facility.

On October 23, 2014, the Board approved a distribution of $0.17875 per preferred unit, or a total distribution of $5.4 million, for the quarter ending September 30, 2014. We will pay this distribution on the preferred units on November 14, 2014 to unitholders of record as of November 4, 2014.

In addition, on October 23, 2014, the Board approved a cash distribution of $0.1345 per unit on our outstanding common units. The distribution will be paid on November 14, 2014 to unitholders of record on November 4, 2014. The distribution is for the three months ended September 30, 2014. The total distribution to be paid is approximately $4.7 million, with approximately $4.4 million and less than $0.2 million paid to our common unitholders and general partner, respectively, and $0.1 million paid to holders of phantom and restricted units pursuant to awards granted under the our long-term incentive plan.

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 Consolidated Financial Statements and footnotes.

The table below summarizes our financial results for the three and nine months ended September 30, 2013 and 2014, reconciled to the most directly comparable GAAP measure:

Operating Results	Three Months ended September 30,		Nine Months ended September 30,		Favorable/(Unfavorable)			
					Three Months		Nine Months	
(in thousands)	2013	2014	2013	2014	$	%	$	%
Operating Margin, excluding depreciation and amortization								
Crude oil terminalling and storage operating margin	$6,625	$3,949	$20,772	$14,766	(2,676)	(40)%	(6,006)	(29)%
Crude oil pipeline services operating margin	7,338	5,520	8,804	7,773	(1,818)	(25)%	(1,031)	(12)%
Crude oil trucking and producer field services operating margin	2,291	1,090	6,986	5,102	(1,201)	(52)%	(1,884)	(27)%
Asphalt services operating margin	12,258	12,075	30,413	30,027	(183)	(1)%	(386)	(1)%
Total operating margin, excluding depreciation and amortization	28,512	22,634	66,975	57,668	(5,878)	(21)%	(9,307)	(14)%
Depreciation and amortization	(5,975)	(6,571)	(17,533)	(19,342)	(596)	(10)%	(1,809)	(10)%
General and administrative expenses	(4,649)	(4,267)	(13,806)	(13,124)	382	8%	682	5%
Asset impairment expense	(123)	—	(123)	—	123	100%	123	100%
Gain on sale of assets	598	808	722	1,780	210	35%	1,058	147%
Operating income:	18,363	12,604	36,235	26,982	(5,759)	(31)%	(9,253)	(26)%
Other income (expense)								
Equity earnings (loss) in unconsolidated entity	(151)	423	(325)	477	574	380%	802	247%
Interest expense	(1,897)	(1,640)	(9,188)	(8,325)	257	14%	863	9%
Income tax expense	(285)	(116)	(451)	(351)	169	59%	100	22%
Net income from continuing operations	16,030	11,271	26,271	18,783	(4,759)	(30)%	(7,488)	(29)%
Loss from discontinued operations	(5,489)	—	(3,542)	—	5,489	(100)%	3,542	(100)%
Net Income	$10,541	$11,271	$22,729	$18,783	730	7%	(3,946)	(17)%

Total operating margin excluding depreciation and amortization decreased from 2013 to 2014 due to several factors, including decreases in our crude oil terminalling and storage segment as changes in market demand for crude oil storage services led to decreases in the rates we charge our customers for those services and decreases in revenue per barrel hauled in our trucking and producer field services segment. In addition, crude oil sales related to accumulated pipeline loss allowances on our pipeline systems were $2.7 million higher during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2014.

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

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Analysis of Operating Segments

Crude oil terminalling and storage segment

Our terminalling and storage segment operations generally consist of fee-based activities associated with providing storage, terminalling 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 and storage segment for the periods indicated:

Operating results	Three Months ended September 30,		Nine Months ended September 30,		Favorable/(Unfavorable)			
					Three Months		Nine Months	
(in thousands)	2013	2014	2013	2014	$	%	$	%
Revenues								
Third Party Revenues	$3,216	$1,875	$9,149	$7,020	(1,341)	(42)%	(2,129)	(23)%
Related Party Revenues	4,477	3,080	14,495	10,726	(1,397)	(31)%	(3,769)	(26)%
Total Revenues	7,693	4,955	23,644	17,746	(2,738)	(36)%	(5,898)	(25)%
Operating Expenses (excluding depreciation and amortization)	1,068	1,006	2,872	2,980	62	6 %	(108)	(4)%
Operating Margin (excluding depreciation and amortization)	$6,625	$3,949	$20,772	$14,766	(2,676)	(40)%	(6,006)	(29)%
Average crude oil stored per month at our Cushing terminal (in thousands of barrels)	4,547	959	4,910	1,873	(3,588)	(79)%	(3,037)	(62)%
Average crude oil delivered to our Cushing terminal (in thousands of barrels per day)	92	58	81	81	(34)	(37)%	—	— %

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

- Revenues and operating margin have decreased due to changes in market dynamics at the Cushing Interchange, which include: a backwardated market for West Texas Intermediate crude, increased Cushing storage capacity, additional pipeline capacity for delivery out of the Cushing Interchange and significant production increases in Kansas, Oklahoma and Texas. These trends have negatively impacted demand for crude oil storage and have created downward pressure on storage rates. The current market environment places more importance on services and connectivity. As a result, we plan to invest approximately $8.0 million in capital expansion projects in Cushing in 2014 to enhance our connectivity and blending services, of which $5.5 million has been spent as of September 30, 2014. We believe our mix and delivery of services will differentiate us from competitors and attract new customers.

Crude oil pipeline services

Our crude oil pipeline services segment operations generally consist of fee-based activity associated with transporting crude oil products on pipelines. Revenues are generated primarily through tariffs and other transportation fees.

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

Operating results	Three Months ended September 30,		Nine Months ended September 30,		Favorable/(Unfavorable)			
					Three Months		Nine Months	
(in thousands)	2013	2014	2013	2014	$	%	$	%
Revenues								
Third Party Revenues	$6,499	$5,906	$12,681	$13,439	(593)	(9)%	758	6%
Related Party Revenues	4,807	2,098	7,179	5,934	(2,709)	(56)%	(1,245)	(17)%
Total Revenues	11,306	8,004	19,860	19,373	(3,302)	(29)%	(487)	(2)%
Operating Expenses (excluding depreciation and amortization)	3,968	2,484	11,056	11,600	1,484	37%	(544)	(5)%
Operating Margin (excluding depreciation and amortization)	$7,338	$5,520	$8,804	$7,773	(1,818)	(25)%	(1,031)	(12)%
Average throughput volume (in thousands of barrels per day)								
Mid-Continent	17	18	18	19	1	6%	1	6%
Eagle North	15	15	14	15	—	—%	1	7%
East Texas	20	18	21	17	(2)	(10)%	(4)	(19)%

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

- Volumes on our East Texas system decreased from 2013 to 2014 primarily as a result of the loss of one customer that took volumes to one of its own pipelines in connection with a reversal of the flow of the customer's pipeline.

- During the nine months ended September 30, 2013, we sold $6.9 million of crude oil related to accumulated pipeline loss allowances on our pipeline systems as compared to $4.2 million during the nine months ended September 30, 2014, a decrease of $2.7 million. During the three months ended September 30, 2013, we sold $6.9 million of crude oil related to accumulated pipeline loss allowances on our pipeline systems as compared to $2.3 million during the three months ended September 30, 2014, a decrease of $4.6 million

- Employment expense increased by $0.1 million, or 4% and $0.4 million, or 8%, for the three and nine months ended September 30, 2014, respectively, as compared to the same periods in 2013 due to additional personnel hired to support the operation of our Oklahoma Arbuckle pipeline and the operation of Advantage Pipeline's Pecos River pipeline and Vitol's Midland pipeline system.

- Repair and maintenance expense increased by $0.3 million, or 98% and $0.8 million, or 36%, for the three and nine months ended September 30, 2014, respectively, as compared to the same periods in 2013 due to planned maintenance and repair expenses associated with our Oklahoma and East Texas pipeline systems.

- Property tax expense increased by $0.4 million for the nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013 due to increases in the assessed values of our pipeline systems.

- The above increases in operating expenses were partially offset by a $1.5 million insurance claim settlement received in September 2014.

Crude oil trucking and producer field services

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 September 30,		Nine Months ended September 30,		Favorable/(Unfavorable)			
					Three Months		Nine Months	
(in thousands)	2013	2014	2013	2014	$	%	$	%
Revenues								
Third Party Revenues	$11,712	$12,264	$36,085	$38,280	552	5 %	2,195	6 %
Related Party Revenues	5,805	4,433	16,370	15,057	(1,372)	(24)%	(1,313)	(8)%
Total Revenues	17,517	16,697	52,455	53,337	(820)	(5)%	882	2 %
Operating Expenses (excluding depreciation and amortization)	15,226	15,607	45,469	48,235	(381)	(3)%	(2,766)	(6)%
Operating Margin (excluding depreciation and amortization)	$2,291	$1,090	$6,986	$5,102	(1,201)	(52)%	(1,884)	(27)%
Average volume (in thousands of barrels per day)	62	61	59	65	(1)	(2)%	6	10 %

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

- We continue to experience consistent demand for our trucking services due to increased crude oil production in the Kansas, Oklahoma and Texas markets we serve. In addition, because the current crude oil market is backwardated, there is a higher demand to deliver barrels from the field to market as soon as possible (as opposed to storing barrels and delivering in a later month). Despite volume increases in 2014, our operating margin has declined due to an increase in pipeline-connected leases in areas we serve, a decrease in the average distance barrels are hauled, and increased costs associated with retaining drivers.

- In addition, because of demand in certain areas we have increased our utilization of third party trucking services. We realize lower operating margins when we utilize third party trucking services. We anticipate a decrease in our utilization of third party trucking services in the near term as we reposition our existing fleet of trucks to service areas with the greatest customer demand.

- We continue to evaluate our overall rate structure and utilization of third party trucking services and expect to implement changes in the upcoming quarters.

Asphalt services segment

Our asphalt services segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for asphalt product and residual fuel oil. Revenue is generated through short- and long-term storage contracts.

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

Operating results	Three Months ended September 30,		Nine Months ended September 30,		Favorable/(Unfavorable)			
					Three Months		Nine Months	
(in thousands)	2013	2014	2013	2014	$	%	$	%
Revenues								
Third Party Revenues	$17,843	$18,456	$47,586	$49,196	613	3 %	1,610	3 %
Related Party Revenues	310	246	1,337	946	(64)	(21)%	(391)	(29)%
Total Revenues	18,153	18,702	48,923	50,142	549	3 %	1,219	2 %
Operating Expenses (excluding depreciation and amortization)	5,895	6,627	18,510	20,115	(732)	(12)%	(1,605)	(9)%
Operating Margin (excluding depreciation and amortization)	$12,258	$12,075	$30,413	$30,027	(183)	(1)%	(386)	(1)%

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

- In December 2013, we conveyed title of our Northumberland, Pennsylvania asphalt storage facility to Koch as part of a litigation settlement. We do not anticipate a significant impact on operating margin in 2014 as a result of this conveyance, and we anticipate operating margin for the remainder of 2014 to be largely in-line with 2013 results.

- Related party revenues decreased due to lower overall contracted storage from short-term spot contracts during 2014 as compared to 2013.

- The increase in operating expenses in 2014 as compared to 2013 is primarily attributable to the timing of maintenance and repair and increased rent expense.

Other Income and Expenses

Depreciation and amortization. Depreciation and amortization increased by $1.8 million to $19.3 million for the nine months ended September 30, 2014 compared to $17.5 million for the nine months ended September 30, 2013, and by $0.6 million to $6.6 million for the three months ended September 30, 2014 compared to $6.0 million for the three months ended September 30, 2013. This increase is primarily due to our Arbuckle pipeline that was placed in service in the fourth quarter of 2013.

General and administrative expenses. General and administrative expenses were relatively consistent during the three and nine months ended September 30, 2013 and 2014. We do not anticipate material changes in general and administrative expenses for the remainder of 2014.

Gain on sale of assets. Gain on sale of assets was $1.8 million for the nine months ended September 30, 2014 compared to $0.7 million for the nine months ended September 30, 2013. Gain on sale of assets was $0.8 million for the three months ended September 30, 2014 compared to $0.6 million for the three months ended September 30, 2013. Gains in 2014 are comprised of sales of surplus, used property and equipment and $0.8 million recognized in relation to reimbursable capital projects. Gains in 2013 are comprised of sales of surplus, used property and equipment and a gain on the sale of pipeline gathering systems.

Equity earnings (loss) in unconsolidated affiliate. The equity earnings (loss) is attributed to our investment in Advantage Pipeline. Losses for 2013 are the result of expenses incurred during the construction phase of the Pecos River Pipeline. On September 17, 2013, commercial service started on Phase I of the system consisting of the Highway 18 Station near Grandfalls, Texas and 36 miles of pipeline connecting to the Longhorn Pipeline in Crane, Texas. During the three and nine months ended September 30, 2014, equity earnings were realized as a result of increased throughput on the pipeline due to the completion of the Crane West station in the second quarter of 2014.

Interest expense. Interest expense represents interest on borrowings under our credit facility 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 September 30, 2014 decreased by $0.3 million compared to the three months ended September 30, 2013. During the three months ended September 30, 2014, we recorded unrealized gains due to the change in fair value of interest rate swaps of $1.1 million. The interest rate swap agreements were entered into during the first quarter of 2014. This decrease in interest expense was partially offset by an increase in interest on our credit facility of $0.3 million due to increases in our average debt outstanding and weighted average interest rate as well as interest expense incurred in connection with settlement payments under our interest rate swap agreements of $0.3 million.

Interest expense decreased by $0.9 million for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013. The nine months ended September 30, 2013 included the write-off of $2.0 million in debt issuance costs and the recognition of $0.2 million of deferred gains related to our prior credit facility. Interest expense related to our credit facility also decreased by $0.5 million due to a decrease in our interest rate under our new credit facility that became effective June 28, 2013. These decreases were partially offset by increases to interest expense related to the interest rate swap agreements and capitalized interest. The nine months ended September 30, 2014 included unrealized losses due to the change in fair value of interest rate swaps of $0.9 million. The interest rate swap agreements were entered into during the first quarter of 2014. Capitalized interest decreased by $0.7 million for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013 due to placing the Arbuckle pipeline in service in the last quarter of 2013.

Loss from discontinued operations. During 2013, we sold our Thompson to Webster Pipeline System in south Texas. In addition, we conveyed title of our Northumberland, Pennsylvania asphalt storage facility to our counterpart as part of a litigation settlement. The operations of these business components are presented as discontinued operations for all periods presented. The loss in 2013 is due to the impairment of the Thompson to Webster Pipeline System.

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.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

The following table summarizes our sources and uses of cash for the nine months ended September 30, 2013 and 2014:

	Nine Months ended September 30,	
	2013	2014
	(in millions)	
Net cash provided by operating activities	$42.3	$39.3
Net cash used in investing activities	(74.5)	(23.4)
Net cash provided by (used in) financing activities	30.7	(17.7)

Operating Activities. Net cash provided by operating activities was $39.3 million for the nine months ended September 30, 2014, as compared to $42.3 million for the nine months ended September 30, 2013. The decrease in cash provided by operating activities is primarily the result of changes in working capital.

Investing Activities. Net cash used in investing activities was $23.4 million for the nine months ended September 30, 2014, as compared to $74.5 million of net cash used in investing activities for the nine months ended September 30, 2013. The nine months ended September 30, 2013 included a $20.0 million investment in Advantage Pipeline. The remaining decrease in cash used in investing activities was primarily the result of a $31.1 million decrease in capital expenditures. Capital expenditures for the nine months ended September 30, 2014 and 2013, respectively, included maintenance capital expenditures of $5.4 million and $13.1 million, respectively, and expansion capital expenditures of $20.0 million and $43.4 million, respectively.

Financing Activities. Net cash used by financing activities was $17.7 million for the nine months ended September 30, 2014, as compared to $30.7 million of net cash provided by financing activities for the nine months ended September 30, 2013. Cash used in financing activities for the nine months ended September 30, 2014 consisted primarily of $25.9 million in distributions to our unitholders and net payments on long term debt of $61.0 million as a result of our approach to cash management. This was partially offset by cash provided by financing activities from the issuance of 9,775,000 common units for a public offering price of $7.61, resulting in proceeds of approximately $71.2 million net of offering costs. Financing activities for the nine months ended September 30, 2013 consisted primarily of $24.9 million in distributions to our unitholders and net borrowings of $63.4 million which were influenced by the timing of our investment in Advantage Pipeline and capital expenditures.

Our Liquidity and Capital Resources

Cash flow from operations and our credit facility are our primary sources of liquidity. At September 30, 2014, we had a working capital surplus of $0.1 million. This is primarily a function of our approach to cash management. At September 30, 2014, we had approximately $187.7 million of availability under our revolving credit facility, although our ability to borrow such funds may be limited by the financial covenants in our credit facility. As of September 30, 2014, we could borrow up to $300.1, or an additional $87.8 million, under our credit facility within our covenant restrictions. As of October 30, 2014, we have aggregate unused commitments under our revolving credit facility of approximately $187.3 million and cash on hand of approximately $5.5 million.

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 or to replace partially or fully depreciated assets or 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 totaled $20.0 million in the nine months ended September 30, 2014 compared to $43.4 million in the nine months ended September 30, 2013. We currently expect our expansion capital expenditures for organic growth projects to be approximately $28.0 million to $33.0 million for all of 2014. Maintenance capital expenditures totaled $3.9 million, net of reimbursable expenditures of $1.5 million, in the nine months ended September 30, 2014 compared to $11.1 million, net of reimbursable expenditures of $2.0 million, in the nine months ended September 30, 2013. We currently expect maintenance capital expenditures to be approximately $7.0 million to $9.0 million, net of reimbursable expenditures, in 2014.

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 facility. 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.

Description of Credit Facility. On June 28, 2013, we entered into an amended and restated credit agreement which consists of a $400.0 million revolving loan facility. On September 15, 2014, we amended our credit facility to, among other things, amend the maximum permitted consolidated total leverage ratio as discussed below and to increase the limit on material project adjustments to EBITDA (as defined in the credit agreement). The proceeds of loans made under our credit agreement may be used for working capital and other general corporate purposes. All references herein to the credit agreement on or after June 28, 2013 refer to the amended and restated credit agreement, as amended on September 15, 2014.

Our credit agreement is guaranteed by all of our existing subsidiaries. Obligations under our credit agreement are secured by first priority liens on substantially all of our assets and those of the guarantors, including all material pipeline, gathering and processing assets, all material storage tanks and asphalt facilities, all material working capital assets and a pledge of all of our equity interests in our subsidiaries.

Our credit agreement includes procedures for adding financial institutions as revolving lenders or for increasing the revolving commitment of any currently committed revolving lender subject to an aggregate maximum of $500.0 million for all revolving loan commitments under our credit agreement.

The credit agreement will mature on June 28, 2018, and all amounts outstanding under our credit agreement shall become due and payable on such date. We may prepay all loans under our credit agreement at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The credit agreement requires mandatory prepayments of amounts outstanding thereunder with the net proceeds certain asset sales, property or casualty insurance claims, and condemnation proceedings, unless we reinvest 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 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 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%) plus an applicable margin that ranges from 1.0% to 2.0%.

We pay 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 we pay a commitment fee on the unused commitments under the credit agreement. The credit agreement does not have a floor for the alternate base rate or the eurodollar rate. The applicable margins for the interest rate, the letter of credit fee and the commitment fee vary quarterly based on our 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 will be 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 we issue 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 4.50 to 1.00; provided that:

- after we deliver the Knight Warrior Pipeline Initiation Certificate (as defined in the credit agreement, but generally meaning that we have spent at least $15.0 million of the projected capital expenditures for our Knight Warrior pipeline project), the maximum permitted consolidated total leverage ratio is 5.00 to 1.00 for the fiscal quarters ending March 31, 2015 through September 30, 2016, 4.75 to 1.00 for the fiscal quarter ending December 31, 2016, and 4.50 to 1.00 for each fiscal quarter thereafter;
- after we deliver the Knight Warrior Pipeline Leverage Election Certificate (as defined in the credit agreement, but generally meaning that we have spent at least 50% of the projected capital expenditures for the Knight Warrior pipeline project), we may elect to increase the maximum permitted consolidated total leverage ratio to 5.50 to 1.00 for two consecutive fiscal quarters ending on or before September 30, 2016; and
- if we make a specified acquisition (as defined in the credit agreement, but generally being an acquisition with consideration in excess of $15.0 million), we may elect to increase the maximum permitted consolidated total leverage ratio to 5.00 to 1.00 from and after the last day of the fiscal quarter immediately preceding the fiscal quarter in which such acquisition occurs to and including the last day of the second full fiscal quarter following the fiscal quarter in which such acquisition occurred.

From and after the date on which we issue 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 after we deliver the Knight Warrior Pipeline Initiation Certificate, the maximum permitted consolidated total leverage ratio is 5.50 to 1.00 for the fiscal quarters ending March 31, 2015 through September 30, 2016, and 5.00 to 1.00 for each fiscal quarter thereafter.

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 we issue qualified senior notes in an aggregate principal amount (when combined with all other qualified senior 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 our 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 our 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 our business;
- enter into operating leases; and
- make certain amendments to our partnership agreement.

At September 30, 2014, our consolidated total leverage ratio was 3.18 to 1.00 and our consolidated interest coverage ratio was 7.12 to 1.00. We were in compliance with all covenants of our credit agreement as of September 30, 2014.

The credit agreement permits us to make quarterly distributions of available cash (as defined in the our 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. We are currently allowed to make distributions to our unitholders in accordance with this covenant; however, we will only make distributions to the extent we have sufficient cash from operations after establishment of cash reserves as determined by the General Partner in accordance with our cash distribution policy, including the establishment of any reserves for the proper conduct of our business.

Each of the following is an event of default under the credit agreement:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;
- failure to observe any other agreement, obligation or covenant in the credit agreement or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- we, or any of our restricted subsidiaries, default under other indebtedness that exceeds a threshold amount;
- judgments against us or any of our restricted subsidiaries, in excess of a threshold amount;
- certain ERISA events involving us or our restricted subsidiaries resulting in a material adverse effect on us;
- bankruptcy or other insolvency events involving our General Partner, us or any of our restricted subsidiaries; and
- a change of control (as defined in the credit agreement, but generally being (i) our General Partner ceasing to own 100% of our general partner interest or ceasing to control us, or (ii) Vitol and Charlesbank ceasing to collectively own and control 50.0% or more of the membership interests of our General Partner).

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

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

Contractual Obligations. A summary of our contractual cash obligations over the next several fiscal years, as of September 30, 2014, is as follows:

	Payments Due by Period				
Contractual Obligations	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
	(in millions)				
Debt obligations[(1)]	$238.6	$7.1	$14.2	$217.3	$—
Operating lease obligations	34.4	7.1	8.3	17.3	1.7
Non-compete agreement[(2)]	0.1	0.1	—	—	—
Employee contract obligations[(3)]	0.2	0.1	0.1	—	—

(1) Represents required future principal repayments of borrowings of $212.0 million and variable rate interest payments of $26.6 million. At September 30, 2014, our borrowings had an interest rate of approximately 3.72%. This interest rate was used to calculate future interest payments. All amounts outstanding under our credit agreement mature in June 2018.

(2) Represents required future payments under a non-compete agreement related to our acquisition of certain field services assets.

(3) Represents required future payments related to employment agreements with certain employees.

Recent Accounting Pronouncements

For information regarding recent accounting developments that may affect our future financial statements, see Note 15 to our 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 facility.

As of October 30, 2014, we had $212.0 million outstanding under our credit facility 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 becomes effective January 28, 2015 and matures on January 28, 2019. Under the terms of the second interest rate swap agreement, we will pay a fixed rate of 1.97% and will receive one-month LIBOR with monthly settlement. The fair market value of the interest rate swaps at September 30, 2014 is a liability of $0.9 million and is recorded in long-term derivative liabilities on the consolidated balance sheet. 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 statements of operations.

During the nine months ended September 30, 2014, the weighted average interest rate under our credit agreement was 3.41%. As of September 30, 2014, borrowings under our credit facility bore interest at a weighted average interest rate of 3.72%.

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 September 30, 2014, 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 annual interest expense of approximately $1.1 million or decreased annual interest expense of $0.2 million, respectively.

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 September 30, 2014, were effective.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting that occurred during the three months ended September 30, 2014 that have materially affected, or are 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 13 to our financial statements, and is incorporated herein by reference thereto.

Item 1A. Risk Factors

Information about risk factors for the three months ended September 30, 2014 does not differ materially from that set forth in Part I, Item 1A, of our Annual Report on Form 10-K for the year ended December 31, 2013 except as listed below.

Risks Related to the Knight Warrior Pipeline Project

Construction and additional development of the Knight Warrior pipeline project subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our operating results, liquidity and financial position.

The Knight Warrior pipeline project will take more than a year to complete, and the construction of the project is subject to a number of factors not always within our control, including issues with obtaining rights-of-way from third-party landowners, the permitting processes, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Some of these factors could result in meaningful delays in the construction of the project. Delays in the completion of the project could have a material adverse effect on our business, financial condition, results of operations and liquidity. The construction of the Knight Warrior pipeline project will require the expenditure of significant amounts of capital, which is subject to variables that may significantly increase expected costs. Should the actual cost of the project exceed our estimates and contingencies, our liquidity and capital position could be adversely affected.

Our expansion projects may not immediately produce operating cash flows.

Expansion projects, including the Knight Warrior pipeline, require us to make significant capital investments over time. For example, our Knight Warrior pipeline project is estimated to cost approximately $300 million and is expected to be complete by March 2016. We will incur financing costs during the planning and construction phases of these projects; however, the operating cash flows we expect these projects to generate will not materialize, if at all, until sometime after the projects are completed and placed into service. As a result, to the extent we finance our projects with borrowings, our leverage may increase during the period prior to the generation of those operating cash flows and, to the extent we finance our projects with equity, our cash available for distribution on a common unit basis may decrease during the period prior to the generation of those operating cash flows. If we experience unanticipated or extended delays in generating operating cash flow from construction projects, we may need to reduce or reprioritize our capital budget in order to meet our capital requirements, and our liquidity and capital position could be adversely affected.

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.

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:	November 6, 2014	By:	/s/ Alex G. Stallings Alex G. Stallings Chief Financial Officer and Secretary
Date:	November 6, 2014	By:	/s/ James R. Griffin James R. Griffin Chief Accounting Officer

INDEX TO EXHIBITS

Exhibit Number	Exhibit Name
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, 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, 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, and incorporated herein by reference).
10.1##	Crude Oil Throughput and Deficiency Agreement, dated August 28, 2014 between Knight Warrior LLC and Eaglebine Crude Oil Marketing LLC.
10.2	First Amendment to Amended and Restated Credit Agreement, dated as of September 15, 2014, by and among the Partnership, Wells Fargo Bank, National Association, as Administrative Agent, and the several lenders from time to time party thereto (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed September 1, 2014, 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 September 30, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) Document and Entity Information; (ii) Consolidated Balance Sheet as of December 31, 2013 and September 30, 2014; (iii) Consolidated Statements of Operations for the nine months ended September 30, 2013 and 2014; (iv) Consolidated Statement of Changes in Partners' Capital for the nine months ended September 30, 2014; (v) Consolidated Statements of Cash Flows for the nine months ended September 30, 2013 and 2014; and (vi) Notes to Consolidated Financial Statements.

* Filed herewith.

\# Furnished herewith

\## Application has been made to the Securities and Exchange Commission for confidential treatment of certain provisions of this exhibit. Omitted material for which confidential treatment has been requested has been separately filed with the Securities and Exchange Commission.