
UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2011

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to _________

Commission File Number 001-33503

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

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

Two Warren Place
6120 South Yale Avenue, Suite 500
Tulsa, Oklahoma 74136
(Address of principal executive offices, zip code)

Registrant’s telephone number, including area code: (918) 237-4000

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 x

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 x

As of November 7, 2011, there were 21,538,462 Series A Preferred Units and 22,657,638 common units outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	As of December 31, 2010	As of September 30, 2011
		(unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,840	$ 1,010
Accounts receivable, net of allowance for doubtful accounts of $429 for both dates	8,824	12,980
Receivables from related parties, net of allowance for doubtful accounts of $0 for both dates	1,912	2,843
Insurance recovery receivable	13,000	13,000
Prepaid insurance	1,413	2,525
Other current assets	2,147	1,673
Total current assets	32,136	34,031
Property, plant and equipment, net of accumulated depreciation of $119,735 and $132,052 at December 31, 2010 and September 30, 2011, respectively	274,069	271,624
Goodwill	7,083	7,216
Debt issuance costs, net	6,675	5,494
Intangibles and other assets, net	3,875	2,410
Total assets	$ 323,838	$ 320,775
LIABILITIES AND PARTNERS' CAPITAL (DEFICIT)		
Current liabilities:		
Accounts payable	$ 8,829	$ 8,057
Accrued loss contingency (see Note 13)	20,200	19,976
Accrued interest payable	357	171
Accrued interest payable to related parties	1,214	5,187
Accrued property taxes payable	2,254	2,990
Unearned revenue	3,506	3,911
Unearned revenue with related parties	2,154	—
Accrued payroll	4,130	4,918
Other accrued liabilities	3,709	3,648
Convertible Debentures (see Note 5)	31,725	44,932
Fair value of derivative embedded within Convertible Debentures	27,550	—
Fair value of rights offering liability	10,441	8,603
Current portion of long-term payable to related parties	1,183	1,580
Total current liabilities	117,252	103,973
Long-term payable to related parties	4,317	3,112
Other long-term liabilities	150	150
Long-term debt (including $15.0 million with related parties for both dates)	239,862	226,000
Commitments and contingencies (Notes 5 and 13)		
Partners' capital (deficit):		

Series A Preferred Units (21,538,462 units issued and outstanding for both dates)		91,376		124,437
Common unitholders (21,890,224 units issued and outstanding for both dates)		478,575		475,990
Subordinated unitholders (12,570,504 and zero units issued and outstanding at December 31, 2010 and September 30, 2011, respectively)		(286,264)		—
General partner interest (2.0% and 3.0% interest at December 31, 2010 and September 30, 2011, respectively, with 1,127,755 general partner units outstanding for both dates)		(321,430)		(612,887)
Total Partners' deficit		(37,743)		(12,460)
Total liabilities and Partners' deficit	$	323,838	$	320,775

See accompanying notes to unaudited consolidated 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, 2010	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2011
	(unaudited)			
Service revenue:				
Third party revenue	$ 31,113	$ 35,124	$ 97,895	$ 99,748
Related party revenue	6,943	11,387	15,637	31,377
Total revenue	38,056	46,511	113,532	131,125
Expenses:				
Operating	23,441	27,617	73,442	85,726
General and administrative	3,883	4,679	11,037	14,065
Total expenses	27,324	32,296	84,479	99,791
Operating income	10,732	14,215	29,053	31,334
Other (income) expenses:				
Interest expense	13,530	9,120	39,502	27,284
Change in fair value of embedded derivative within convertible debt	—	(15,358)	—	(20,224)
Change in fair value of rights offering liability	—	(8,224)	—	(1,838)
Income (loss) before income taxes	(2,798)	28,677	(10,449)	26,112
Provision for income taxes	50	72	151	219
Net income (loss)	$ (2,848)	$ 28,605	$ (10,600)	$ 25,893
Allocation of net income (loss) for calculation of earnings per unit:				
General partner interest in net income (loss)	$ (57)	$ 643	$ (209)	$ 754
Preferred interest in net income	$ —	$ 2,975	$ —	$ 11,124
Beneficial conversion feature attributable to preferred units	$ —	$ 11,141	$ —	$ 33,061
Income (loss) available to common and subordinated unitholders	$ (2,791)	$ 13,846	$ (10,391)	$ (19,046)
Basic and diluted net income (loss) per common unit	$ (0.08)	$ 0.38	$ (0.30)	$ (0.56)
Basic and diluted net income (loss) per subordinated unit	$ (0.08)	$ 0.42	$ (0.30)	$ (0.52)
Weighted average common units outstanding - basic and diluted	21,728	21,890	21,728	21,890
Weighted average subordinated units outstanding - basic and diluted	12,571	10,248	12,571	11,788

See accompanying notes to unaudited consolidated financial statements.

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BLUEKNIGHT ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL (DEFICIT)

(in thousands)

	Common Unitholders	Subordinated Unitholders	Series A Preferred Unitholders (unaudited)	General Partner Interest	Total Partners' Deficit
Balance, December 31, 2010	$ 478,575	$ (286,264)	$ 91,376	$ (321,430)	$ (37,743)
Net income	11,540	5,674	8,149	530	25,893
Equity-based incentive compensation	246	124	—	7	377
Amortization of beneficial conversion feature of Preferred units	(21,697)	(11,364)	33,061	—	—
Distributions	—	—	(8,149)	(164)	(8,313)
Debt conversion option classified as equity	7,326	—	—	—	7,326
Contribution and cancellation of subordinated units	—	291,830	—	(291,830)	—
Balance, September 30, 2011	$ 475,990	$ —	$ 124,437	$ (612,887)	$ (12,460)

See accompanying notes to unaudited consolidated financial statements.

BLUEKNIGHT ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2011
	(unaudited)	
Cash flows from operating activities:		
Net income (loss)	$ (10,600)	$ 25,893
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	16,228	17,066
Amortization and write-off of debt issuance costs	3,640	1,461
Amortization of subordinated debenture discount	—	13,207
Decrease in fair value of embedded derivative within convertible debt	—	(20,224)
Decrease in fair value of rights offering liability	—	(1,838)
Asset impairment charge	779	—
Gain on sale of assets	(103)	(1,852)
Equity-based incentive compensation	27	377
Changes in assets and liabilities		
Decrease (increase) in accounts receivable	138	(4,156)
Decrease (increase) in receivables from related parties	130	(931)
Decrease in prepaid insurance	1,020	450
Decrease in other current assets	1,076	474
Decrease (increase) in other assets	(276)	1,118
Decrease in accounts payable	(1,169)	(2,036)
Increase (decrease) in accrued interest payable	6,377	(186)
Increase in accrued interest payable to related parties	61	3,973
Increase (decrease) in accrued property taxes	(570)	736
Increase (decrease) in unearned revenue	(2,649)	405
Increase (decrease) in unearned revenue from related parties	955	(2,154)
Increase in accrued payroll	588	788
Increase (decrease) in other accrued liabilities	832	(795)
Net cash provided by operating activities	16,484	31,776
Cash flows from investing activities:		
Acquisitions	—	(133)
Capital expenditures	(11,279)	(13,686)
Proceeds from sale of assets	1,628	2,244
Net cash used in investing activities	(9,651)	(11,575)
Cash flows from financing activities:		
Payment on insurance premium financing agreement	(174)	(768)
Debt issuance costs	(1,119)	(280)
Payments on capital lease obligations	(248)	—
Borrowings from related party	5,500	—
Payments on long-term payable to related party	—	(808)
Borrowings under credit facility	40,700	6,000
Payments under credit facility	(54,971)	(19,862)
Distributions	—	(8,313)
Net cash used in financing activities	(10,312)	(24,031)

Net decrease in cash and cash equivalents		(3,479)		(3,830)
Cash and cash equivalents at beginning of period		5,548		4,840
Cash and cash equivalents at end of period	$	2,069	$	1,010
Supplemental disclosure of cash flow information:				
Increase in accounts payable related to purchase of property, plant and equipment	$	189	$	1,264
Increase in accrued liabilities related to insurance premium financing agreement	$	407	$	1,278

See accompanying notes to unaudited consolidated financial statements.

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

1. ORGANIZATION AND NATURE OF BUSINESS

Blueknight Energy Partners, L.P. (formerly SemGroup Energy Partners, L.P.) and subsidiaries (the "Partnership") is a publicly traded master limited partnership with operations in twenty-three 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, which represent limited partnership interests in the Partnership, are listed on the NASDAQ Global Market. The Partnership was formed in February of 2007 as a Delaware master limited partnership initially to own, operate and develop a diversified portfolio of complementary midstream energy assets.

2. BASIS OF 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, 2010 and 2011, the consolidated statement of changes in partners' capital (deficit) for the nine months ended September 30, 2011, the statement of cash flows for the nine months ended September 30, 2010 and 2011, and the consolidated balance sheet as of September 30, 2011 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 present 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 2010 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, 2010 filed with the Securities and Exchange Commission (the "SEC") on March 16, 2011 (the "2010 Form 10-K"). Interim financial results are not necessarily indicative of the results to be expected for an annual period. The Partnership's significant accounting policies are consistent with those disclosed in Note 3 of the Notes to Consolidated Financial Statements in our 2010 Form 10-K.

3. RECENT EVENTS

On October 25, 2010, the Partnership entered into a Global Transaction Agreement by and among the Partnership, Blueknight Energy Partners, G.P., L.L.C., which is the Partnership's general partner (the "General Partner"), Vitol ("Vitol" refers to Vitol Holding B.V., its affiliates and subsidiaries other than the Partnership's general partner and the Partnership) and Charlesbank ("Charlesbank" refers to Charlesbank Capital Partners, LLC, its affiliates and subsidiaries other than the Partnership's general partner and the Partnership), pursuant to which the Partnership effected a refinancing of its existing debt. The Global Transaction Agreement contemplated three events comprised of Phase I Transactions, a unitholder vote and Phase II Transactions. Phase I transactions were completed concurrently with the execution of the Global Transaction Agreement. For a detailed description of the Global Transaction Agreement, see the Partnership's 2010 Form 10-K.

On May 12, 2011, the Partnership, the General Partner, Vitol and Charlesbank entered into the First Amendment to Global Transaction Agreement (the "Amendment") pursuant to which the Unitholder Vote Transactions and the Phase II Transactions contemplated in the Global Transaction Agreement were modified.

Pursuant to the Global Transaction Agreement, as amended by the Amendment, the General Partner filed a definitive proxy statement with the Securities and Exchange Commission (the "SEC") relating to a special meeting (the "Unitholder Meeting") that occurred on September 14, 2011 during which the Partnership's unitholders considered and voted upon (i) certain amendments to the Partnership's partnership agreement (the "Partnership Agreement Amendment Proposal") as more fully set forth below and (ii) an amendment to the General Partner's Long-Term Incentive Plan to increase the number of common units issuable under such plan by 1,350,000 common units from 1,250,000 common units to 2,600,000 common units (the "LTIP Proposal"). Pursuant to the Partnership Agreement Amendment Proposal, the Partnership's partnership agreement would be amended to:

- reset (1) the minimum quarterly distribution to $0.11 per unit per quarter from $0.3125 per unit per quarter, (2) the first target distribution to $0.1265 per unit per quarter from $0.3594 per unit per quarter, (3) the second target distribution to $0.1375 per unit per quarter from $0.3906 per unit per quarter and (4) the third target distribution to $0.1825 per unit per quarter from $0.4688 per unit per quarter;

- waive the cumulative common unit arrearage;

- remove provisions in the partnership agreement relating to the subordinated units, including concepts such as a subordination period (and any provisions that expressly apply only during the subordination period) and common unit arrearage, in connection with the transfer to the Partnership, and its subsequent cancellation, of all of the Partnership's outstanding subordinated units;

- provide that distributions shall not accrue or be paid to the holders of the Partnership's incentive distribution rights for an eight quarter period beginning with the quarter in which the special meeting occurs;

- provide that during the period beginning on the date of this special meeting and ending on June 30, 2015 (the "Senior Security Restriction Period"), the Partnership will not issue any class or series of partnership securities that, with respect to distributions on such partnership securities or distributions upon liquidation of the Partnership, ranks senior to the common units during the Senior Security Restriction Period, or "Senior Securities", without the consent of the holders of at least a majority of the outstanding common units (excluding the common units held by the General Partner and its affiliates and excluding any Senior Securities that are convertible into common units), subject to certain exceptions; and

- make certain other amendments relating to the conversion of the Partnership's Series A Preferred Units (the "Preferred Units").

On September 14, 2011, the Partnership's unitholders approved the proposals outlined above. As a result, (i) the General Partner adopted the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership (the "Amended and Restated Partnership Agreement") to reflect the approval of the Partnership Agreement Amendment Proposal, (ii) Vitol and Charlesbank transferred all of the Partnership's outstanding subordinated units to the Partnership and the Partnership cancelled such subordinated units and (iii) the Partnership was obligated to undertake an approximately $77 million rights offering.

On October 3, 2011, the Partnership commenced the rights offering. Pursuant to the terms of the rights offering, the Partnership distributed to its common unitholders of record as of the close of business on September 27, 2011, 0.5412 rights for each outstanding common unit, with each whole right entitling the holder to acquire, for a subscription price of $6.50, a newly issued Preferred Unit. The rights offering expired on October 31, 2011.

The results of the rights offering indicate that the rights offering was over-subscribed and, accordingly, on November 9, 2011, the Partnership issued a total of 11,846,990 Preferred Units to unitholders that exercised their rights. The Partnership received net proceeds of approximately $77 million from the rights offering. The net proceeds from the rights offering, after deducting expenses, were used to redeem convertible debentures in the aggregate principal amount of $50 million plus accrued interest thereon that the Partnership issued to Vitol and Charlesbank (the "Convertible Debentures") and to repurchase an aggregate of 3,225,494 Preferred Units from Vitol and Charlesbank. The Partnership expects that Preferred Units subscribed for in the rights offering will be mailed to participants or credited through DTC on or about Wednesday, November 9, 2011. In addition, the Partnership expects that the

Preferred Units will begin trading on the NASDAQ Global Market on or about Thursday, November 10, 2011 under the symbol “BKEPP.”

4. PROPERTY, PLANT AND EQUIPMENT

	Estimated Useful Lives (Years)	December 31, 2010	September 30, 2011
		(dollars in thousands)	
Land	N/A	$ 15,611	$ 16,981
Land improvements	10-20	5,268	5,731
Pipelines and facilities	5-31	149,402	152,927
Storage and terminal facilities	10-35	166,538	170,226
Transportation equipment	3-10	24,177	20,839
Office property and equipment and other	3-31	21,978	23,500
Pipeline linefill and tank bottoms	N/A	7,763	7,493
Construction-in-progress	N/A	3,067	4,633
Property, plant and equipment, gross		393,804	402,330
Assets held for sale, net		—	928
Accumulated depreciation		(119,735)	(131,634)
Property, plant and equipment, net		$ 274,069	$ 271,624

Depreciation expense for the nine months ended September 30, 2010 and 2011 was $16.2 million and $17.0 million, respectively.

5. DEBT

On October 25, 2010, the Partnership entered into a new credit agreement, which includes a $200.0 million term loan facility and a $75.0 million revolving loan facility. Vitol is a lender under the credit agreement and has committed to loan the Partnership $15.0 million pursuant to such agreement. The entire amount of the term loan and approximately $43.9 million of the revolver was drawn on the transaction date in connection with repaying all existing indebtedness under the Partnership's prior credit agreement. The proceeds of loans made under the credit agreement may be used for working capital and other general corporate purposes of the Partnership.

On April 5, 2011, the Partnership entered into a Joinder Agreement whereby the Partnership's revolving credit facility was increased from $75.0 million to $95.0 million. As of November 7, 2011, approximately $22.7 million of revolver borrowings and letters of credit were outstanding under the credit facility, leaving the Partnership with approximately $72.3 million available capacity for additional revolver borrowings and letters of credit under the credit facility.

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 $200.0 million for all revolving loan commitments under the credit agreement.

The credit agreement will mature on October 25, 2014, 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, casualty events and debt incurrences, and, in certain circumstances, with a portion of the Partnership's excess cash flow (as defined in the credit agreement). These mandatory prepayments will be applied to the term loan under the credit agreement until it is repaid in full, then applied to reduce commitments under the revolving loan facility.

Through May 15, 2011, borrowings under the credit agreement bore interest, at the Partnership's option, at either (i) the ABR (the highest of the administrative agent's prime rate, the federal funds rate plus 0.5%, or the one-month eurodollar rate (as defined in the credit agreement) plus 1%), plus an applicable margin of 3.25%, or (ii) the eurodollar rate plus an applicable margin of 4.25%. After approximately May 15, 2011, the applicable margin for loans accruing interest based on the ABR ranges from 3.0% to 3.5%, and the applicable margin for loans accruing interest based on the eurodollar rate ranges from 4.0% to 4.5%, in each case depending on the Partnership's consolidated total leverage ratio (as defined in the credit agreement). 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 of 0.50% per annum on the unused availability under the credit agreement. The credit agreement does not have a floor for the ABR or the eurodollar rate. In connection with entering into the credit agreement, the Partnership paid certain upfront fees to the lenders thereunder, and the Partnership paid certain arrangement and other fees to the arranger and administrative agent of the credit agreement. Vitol received its pro rata portion of such fees as a lender under the credit agreement.

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 (except for the consolidated interest coverage ratio, which builds to a four-quarter test).

The maximum permitted consolidated total leverage ratio is as follows:

- 4.75 to 1.00 for the fiscal quarters ending September 30, 2011 and December 31, 2011; and
- 4.50 to 1.00 for the fiscal quarter ending March 31, 2012 and each fiscal quarter thereafter.

The minimum permitted consolidated interest coverage ratio (as defined in the credit agreement) is 3.00 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

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

- create, incur or assume liens;
- engage in mergers or acquisitions;
- repurchase the Partnership's equity, make distributions to unitholders and make certain other restricted payments;
- make investments;
- modify the terms of the Convertible Debentures (as defined below) and certain other indebtedness, or prepay certain indebtedness;
- engage in transactions with affiliates;
- enter into certain burdensome contracts;
- 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, 2011, the Partnership's leverage ratio was 3.76 and the interest coverage ratio was 5.01. The Partnership was in compliance with all covenants of its credit agreement as of September 30, 2011.

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: (i) no default or event of default exists under the credit agreement, (ii) the Partnership has, on a pro forma basis after giving effect to such distribution, at least $10.0 million of availability under the revolving loan facility, and (iii) the Partnership's consolidated total leverage ratio, on a pro forma basis, would not be greater than (x) 4.5 to 1.0 for any fiscal quarter on or prior to the fiscal quarter ending June 30, 2011, (y) 4.25 to 1.0 for the fiscal quarters ending September 30, 2011 and December 31, 2011, or (z) 4.00 to 1.0 for any fiscal quarter ending on or after March 31, 2012. The Partnership is currently allowed to make distributions to its unitholders in accordance with these covenants; 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 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 6 for additional information regarding distributions.

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

- 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 Partnership's, or any of its subsidiaries', default under other indebtedness that exceeds a threshold amount;
- judgments against the Partnership or any of its subsidiaries, in excess of a threshold amount;
- certain ERISA events involving the Partnership or any of its subsidiaries, in excess of a threshold amount;
- bankruptcy or other insolvency events involving the Partnership or any of its subsidiaries; and
- a change in control (as defined in the credit agreement).

If an event of default relating to bankruptcy or other insolvency events occurs, 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.

It will constitute a change of control under the credit agreement if either Vitol or Charlesbank ceases to own, directly or indirectly, exactly 50% of the membership interests of the General Partner or if the General Partner ceases to be controlled by both Vitol and Charlesbank.

Interest expense related to debt issuance cost amortization for the three and nine month periods ended September 30, 2010 was $1.3 million and $3.6 million, respectively, and for the three and nine month periods ended September 30, 2011 was $0.5 million and $1.5 million, respectively. The Partnership capitalized debt issuance costs of $1.1 million during the nine month period ended September 30, 2010, and $0.3 million during the nine months ended September 30, 2011, respectively.

During the three months ended September 30, 2011, the weighted average interest rate under the credit agreement incurred by the Partnership was 4.6% and the total weighted average interest rate, including interest associated with the Convertible Debentures and related debt discount and the Vitol Throughput Capacity Agreement was 12.4% resulting in interest expense of approximately $9.1 million.

In October of 2010 the Partnership issued the Convertible Debentures in a private placement in the aggregate principal amount of $50.0 million. If not previously redeemed, the Convertible Debentures, including all outstanding principal and unpaid interest, will convert to Preferred Units on December 31, 2011. The Partnership redeemed teh Convertible Debentures on November 9, 2011. This conversion feature was considered an embedded derivative, which the Partnership was required to separately value. The Partnership had previously bifurcated this embedded derivative and estimated the fair value each reporting period. In connection with the establishment of the conversion price for the Preferred Units following the special meeting of the Partnership's unitholders in September 2011, the number of Preferred Units issuable upon conversion of the Convertible Debentures would have been an amount equal to (i) the sum of the outstanding principal and any accrued and unpaid interest being converted, divided by (ii) 6.50. The establishment of the conversion rate resulted in the embedded derivative meeting the scope exception in ASC 815-15 –

Embedded Derivatives, and, therefore, the Partnership has reclassified the embedded derivative as partners' capital as of September 30, 2011. The discount created by allocating a portion of the issuance proceeds to the embedded derivative continues to be amortized to interest expense over the term of the Convertible Debentures using the effective interest method.

The Partnership estimated the fair value of the embedded derivative liability to be $27.6 million at December 31, 2010. At September 14, 2011 the fair value of this derivative liability was estimated to be $7.3 million, and subsequently, as noted above, the embedded derivative was reclassified as partners' capital as of September 30, 2011.

Changes to the fair value of the embedded derivative are reflected on the Partnership's consolidated statements of operations as "Change in fair value of embedded derivative within convertible debt." The value of the embedded derivative is contingent on changes in the expected fair value of the Partnership's preferred units. The Partnership recorded other income of $15.4 million and $20.2 million due to the change in the fair value of this embedded derivative in the three and nine months ended September 30, 2011, respectively.

In addition, the recording of the embedded derivative liability related to the Convertible Debentures resulted in the Partnership recording a $20.9 million debt discount on Convertible Debentures. The debt discount is amortized to interest expense through the mandatory conversion date of December 31, 2011 using the effective interest method. The Partnership recognized non-cash interest expense of $4.5 million and $13.2 million in the three and nine months ended September 30, 2011, respectively, due to the amortization of the debt discount.

6. DISTRIBUTIONS

The Partnership has not made a cash distribution to its common unitholders since May 15, 2008 due, in part, to the events of default that existed under its former credit agreement, restrictions under such credit agreement, and the uncertainty of its future cash flows relating to SemCorp's bankruptcy filings ("SemCorp" refers to SemGroup Corporation and its predecessors including SemGroup, L.P., subsidiaries and affiliates other than the Partnership and the General Partner during periods in which the Partnership and the General Partner were affiliated with SemGroup, L.P.). As a result of the approval of the Partnership Agreement Amendment Proposal on September 14, 2011, all cumulative common unit arrearages were eliminated. The Partnership's common unitholders will be required to pay taxes on their share of the Partnership's taxable income even though they did not receive a cash distribution for the quarters ended June 30, 2008 through September 30, 2011. The Partnership is currently allowed to make distributions to its unitholders in accordance with its debt covenants; 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 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. Based on current estimates, management anticipates that it will recommend to the board of directors of the General Partner (the "Board") that the Partnership resume paying distributions on the Partnership's common units beginning with the fourth quarter of 2011 (which distribution would be paid in the first quarter of 2012), however, there can be no assurance that such distribution will be paid.

On October 24, 2011, the Board approved a distribution of $0.14 per Preferred Unit, or a total distribution of $3.0 million. The Partnership paid this distribution on the preferred units on November 7, 2011 to Preferred Unitholders of record as of October 30, 2011.

7. NET INCOME PER COMMON AND SUBORDINATED 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 loss per common and subordinated unit (in thousands, except per unit data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2011	2010	2011
Net income (loss)	$ (2,848)	$ 28,605	$ (10,600)	$ 25,893
Less: Beneficial conversion feature attributable to preferred units	—	11,141	—	33,061
Less: Preferred interest in net income	—	2,975	—	11,124

Less: General partner interest in net income (loss)		(57)		643			(209)		754	
Net income (loss) available to common and subordinated unitholders	$	(2,791)	$	13,846		$	(10,391)	$	(19,046)	
Basic and diluted weighted average number of units:										
Common units		21,728		21,890			21,728		21,890	
Subordinated units		12,571		10,248			12,571		11,788	
Restricted and phantom units		13		456			13		380	
Basic and diluted net income (loss) per common unit	$	(0.08)	$	0.38		$	(0.30)	$	(0.56)	
Basic and diluted net income (loss) per subordinated unit	$	(0.08)	$	0.42	(1)	$	(0.30)	$	(0.52)	(1)

(1) On September 14, 2011, Vitol and Charlesbank transferred all of the Partnership's outstanding subordinated units to the Partnership and the Partnership cancelled such subordinated units. Net income (loss) per subordinated unit represents income (loss) through the September 14, 2011 cancellation of the subordinated units.

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8. RELATED PARTY TRANSACTIONS

The Partnership provides crude oil gathering, transportation, terminalling and storage services to Vitol. For the three and nine months ended September 30, 2010, the Partnership recognized revenues of $6.9 million and $15.6 million, respectively, for services provided to Vitol. For the three and nine months ended September 30, 2011, the Partnership recognized revenues of $11.4 million and $31.4 million, respectively, for services provided to Vitol. As of September 30, 2011, the Partnership had receivables from Vitol of $2.8 million.

Vitol Storage Agreements

In connection with the Partnership's acquisition of certain of its crude oil storage assets from SemCorp in May 2008, the Partnership was assigned from SemCorp a storage agreement with Vitol under which the Partnership provides crude oil storage services to Vitol (the "2008 Vitol Storage Agreement"). The initial term of the 2008 Vitol Storage Agreement was from June 1, 2008 through June 30, 2010. This agreement was amended in 2010 to extend the term of the agreement until June 1, 2011 and again in 2011 to extend the term of the agreement to June 1, 2012. Because Vitol was a third party (and not a related or affiliated party) at the time of entering into the 2008 Vitol Storage Agreement, such agreement was not approved by the Board or the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions. Vitol became a related party when it acquired the Partnership's General Partner in November 2009. Since the amendments occurred subsequent to the Vitol Change of Control, they were reviewed and approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the partnership agreement. The Partnership earned revenues of approximately $3.2 million and $3.3 million from Vitol with respect to services provided pursuant to the 2008 Vitol Storage Agreement for the three month periods ended September 30, 2010 and 2011, respectively. The Partnership earned revenues of approximately $9.2 million and $9.9 million from Vitol with respect to services provided pursuant to the 2008 Vitol Storage Agreement for the nine month periods ended September 30, 2010 and 2011, respectively. The Partnership believes that the rates it charges Vitol under the 2008 Vitol Storage Agreement are fair and reasonable to the Partnership and its unitholders and are comparable with the rates the Partnership charges third parties.

In March of 2010, the Partnership entered into a second crude oil storage services agreement with Vitol under which the Partnership began providing additional crude oil storage services to Vitol effective May 1, 2010 (the "2010 Vitol Storage Agreement"). The initial term of the 2010 Vitol Storage Agreement is five years commencing on May 1, 2010, subject to automatic renewal periods for successive one year periods until terminated by either party with ninety days prior notice. The 2010 Vitol Storage Agreement was reviewed and approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the partnership agreement. The Partnership generated revenues under this agreement of approximately $3.0 million and $3.1 million during the three month periods ended September 30, 2010 and 2011, respectively. The Partnership generated revenues under this agreement of approximately $5.0 million and $9.2 million during the nine month periods ended September 30, 2010 and 2011, respectively. The Partnership believes that the rates it charges Vitol under the 2010 Vitol Storage Agreement are fair and reasonable to the Partnership and its unitholders and are comparable with the rates the Partnership charges third parties.

Vitol Master Lease Agreement

In July of 2010, the Partnership and Vitol entered into a Master Agreement (the "Master Agreement") relating to the lease of certain vehicles by the Partnership from Vitol. Pursuant to the Master Agreement, the Partnership may lease certain vehicles, including light duty trucks, tractors, tank trailers and bobtail tank trucks, from Vitol for periods ranging from 36 months to 84 months depending on the type of vehicle. The Partnership will have the opportunity to purchase each vehicle at the end of the lease at the estimated residual value of such vehicle. Leases under the Master

Agreement are accounted for as operating leases. During the three and nine months ended September 30, 2011, the Partnership recorded expenses under this agreement of approximately $0.1 million and $0.4 million, respectively. The Master Agreement was approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of its partnership agreement. In September of 2011, the Partnership entered into a new master lease agreement with an unrelated third party and terminated the Master Agreement with Vitol.

Vitol Throughput Capacity Agreement

In August of 2010, the Partnership and Vitol entered into a Throughput Capacity Agreement (the "ENPS Throughput Agreement"). Pursuant to the ENPS Throughput Agreement, Vitol purchased 100% of the throughput capacity on the Partnership's Eagle North Pipeline System ("ENPS"). The Partnership put ENPS in service in December of 2010. In September 2010, Vitol paid the Partnership a prepaid fee equal to $5.5 million and Vitol will pay additional usage fees for every barrel delivered by or on behalf of Vitol on ENPS. This $5.5 million fee received from Vitol is accounted for as a long-term payable to a related party and is reflected as such on the Partnership's consolidated balance sheet as of September 30, 2011. In addition, if the payments made by Vitol in any contract year under the ENPS Throughput Agreement are in the aggregate less than $2.4 million, then Vitol will pay the Partnership a deficiency payment equal to $2.4 million minus the aggregate amount of all payments made by Vitol during such contract year. The ENPS Throughput Agreement has a term that extends for four years after ENPS is completed and may be extended by mutual agreement of the parties for additional one-year terms. If the capacity on ENPS is unavailable for use by Vitol for more than 60 days, whether consecutive or nonconsecutive, during the term of the ENPS Throughput Agreement, then Vitol shall have the right to terminate the ENPS Throughput Agreement within six months after such lack of capacity. The Partnership has previously contracted to provide throughput services on ENPS to a third party and Vitol's rights to the capacity of ENPS are subordinate to the rights of such third party. In addition, for so long as a default by Vitol relating to payments under the ENPS Throughput Agreement has not occurred and is continuing, the Partnership will remit to Vitol any and all tariffs and deficiency payments received by the Partnership or its affiliates from such third party pursuant to its agreement with the Partnership. The ENPS Throughput Agreement was approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of its partnership agreement.

During the three and nine months ended September 30, 2010, the Partnership incurred interest expense under this agreement of approximately $0.1 million. During the three and nine months ended September 30, 2011, the Partnership incurred interest expense under this agreement of approximately $0.2 million and $0.6 million, respectively. The agreement has an effective annual interest rate of 14.1% and matures on December 31, 2014.

Vitol's Commitment under the Partnership's Credit Agreement

Vitol is a lender under the Partnership's current credit agreement and has committed to loan the Partnership $15.0 million pursuant to such agreement. During the three and nine months ended September 30, 2011, Vitol received its pro rata portion of the interest payments in connection with being a lender under the credit agreement and received approximately $0.2 million and $0.5 million, respectively, in connection therewith.

9. LONG-TERM INCENTIVE PLAN

In July of 2007, the General Partner adopted the Blueknight Energy Partners G.P., L.L.C. Long-Term Incentive Plan (the "Plan"). The compensation committee of the Board administers the Plan. The Plan authorizes the grant of an aggregate of 1.25 million common units deliverable upon vesting. On September 14, 2011, the Partnership's unitholders approved an amendment to the Plan to increase the number of common units issuable under such plan by 1,350,000 common units from 1,250,000 common units to 2,600,000 common units. Although other types of awards are contemplated under the Plan, currently outstanding awards include "phantom" units, which convey the right to receive common units upon vesting, and "restricted" units, which are grants of common units restricted until the time of vesting. The phantom unit awards also include distribution equivalent rights ("DERs").

Subject to applicable earning criteria, a DER entitles the grantee to a cash payment equal to the cash distribution paid on an outstanding common unit prior to the vesting date of the underlying award. Recipients of restricted 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 March 2011, grants for 299,900 phantom common units were made, all of which vest on January 1, 2014. 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 \$8.25 per unit, which is the closing market price on the March 10, 2011 grant date of the awards. The value of these award grants was approximately \$2.5 million on their grant date, and the unrecognized estimated compensation cost at September 30, 2011 was \$1.6 million, which will be recognized over the remaining vesting period. As of September 30, 2011, the Partnership expects approximately 75% of these awards will vest. The Partnership's equity-based incentive compensation expense for the three and nine months ended September 30, 2011 was \$0.2 million and \$0.4 million, respectively.

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

	Number of Shares	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2010	7,500	$ 7.30
Granted	299,900	8.25
Vested	—	—
Forfeited	(1,000)	8.25
Nonvested at September 30, 2011	306,400	$ 8.23

10. EMPLOYEE BENEFIT PLAN

Under the Partnership's 401(k) Plan, which was formed in 2009, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the 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 $0.2 million and $0.4 million, respectively, for the three months ended September 30, 2010 and 2011, respectively, for discretionary contributions under the plan. The Partnership recognized expense of $0.8 million and $0.9 million, respectively, for the nine months ended September 30, 2010 and 2011, respectively, for discretionary contributions under the 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, and to minimize the use of unobservable inputs when determining fair value.

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

Fair Value Measurements as of December 31, 2010

Description	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities:				
Fair value of derivative embedded within the Convertible Debentures	$ 27,550	$ —	$ —	$ 27,550
Fair value of rights offering liability	$ 10,441	$ —	$ —	$ 10,441
Total	$ 37,991	$ —	$ —	$ 37,991

	Fair Value Measurements as of September 30, 2011			
Description	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities:				
Fair value of rights offering liability	$ 8,603	$ —	$ —	$ 8,603
Total	$ 8,603	$ —	$ —	$ 8,603

The fair value of the embedded derivative within the Convertible Debentures was derived using a valuation model and has been classified as Level 3. The valuation model used is a discounted cash flow model (income approach) that assumes future distribution payments by the Partnership and utilizes interest rates and credit spreads for subordinated debt to preferred stock to determine the fair value of the derivative embedded within the Convertible Debentures. The change in fair value of the derivative liability for the three and nine months ended September 30, 2011 of $15.4 million and $20.2 million, respectively, is included in other (income) expense in the Partnership's consolidated statements of operations. In connection with the establishment of the conversion price for the Preferred Units following the special meeting of the Partnership's unitholders in September 2011, the number of Preferred Units issuable upon conversion of the Convertible Debentures will be an amount equal to (i) the sum of the outstanding principal and any accrued and unpaid interest being converted, divided by (ii) 6.50. The establishment of the conversion rate resulted in the embedded derivative meeting the scope exception in ASC 815-15 – Embedded Derivatives, and, therefore, the Partnership has reclassified the embedded derivative as partners' capital as of September 30, 2011.

The fair value of the rights offering liability related to certain rights that have been offered to common unitholders under the approved Global Transaction Agreement was derived using a valuation model and has been classified as Level 3. The valuation model used is a probability-weighted model (income approach) and assumes the number of rights that are exercised as well as the expected fair value of the Preferred Units at the time such rights are exercised. The change in fair value of the rights offering liability for the three and nine months ended September 30, 2011 of $8.2 million and $1.8 million, respectively, is included in other (income) expense in the Partnership's consolidated statements of operations.

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)	
	For the Three Months Ended September 30, 2011	For the Nine Months Ended September 30, 2011
Beginning Balance	$ 39,511	$ 37,991
Total gains or losses (realized/unrealized)		
Included in earnings	(23,582)	(22,062)
Included in other comprehensive income	—	—
Purchases, issuances, and settlements(1)	(7,326)	(7,326)
Transfers in and/or out of Level 3	—	—
Balance at September 30, 2011	$ 8,603	$ 8,603
	$ (8,224)	$ (1,838)

The amount of total income for the period included in earnings attributable to the change in unrealized gains for liabilities still held at the reporting date	

(1) As noted above, the Partnership reclassified the embedded derivative within Convertible Debentures to partners' capital as of September 30, 2011.

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. During the fourth quarter of 2010, the Partnership changed the structure of its internal organization in a manner that caused the composition of its reportable segments to change. Previously, the crude oil pipeline services segment and the crude oil trucking and producer field services segment were presented on a combined basis. The change in the Partnership's internal organization was prompted by the December 2010 acquisition of a producer field services business and the December 2010 placement of the ENPS into service. All periods prior to this change in the Partnership's internal organization have been restated to reflect the Partnership's current operating segments.

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 ENPS, 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. In December 2010, the Partnership placed into service a third pipeline system, ENPS, originating in Cushing, Oklahoma and terminating in Ardmore, Oklahoma.

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 terminalling and storage facilities located in twenty-two 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 (loss) 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 between segments. Income (loss) 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):

	Crude Oil Terminalling and Storage Services	Crude Oil Pipeline Services	Crude Oil Trucking and Producer Field Services	Asphalt Services	Total	
Three Months Ended September 30, 2010						
Service revenue						
Third party revenue	$ 3,274	$ 2,702	$ 10,331	$ 14,806	$ 31,113	
Related party revenue	6,393	394	156	—	6,943	
Total revenue for reportable segments	9,667	3,096	10,487	14,806	38,056	
Operating expenses (excluding depreciation and amortization)	1,155	2,450	9,657	4,864	18,126	
Operating margin (excluding depreciation and amortization)	8,512	646	830	9,942	19,930	(1)
Total assets (end of period)	77,359	71,455	18,223	128,919	295,956	
Three Months Ended September 30, 2011						
Service revenue						
Third party revenue	$ 2,941	$ 4,408	$ 10,170	$ 17,605	$ 35,124	
Related party revenue	6,683	1,220	3,484	—	11,387	
Total revenue for reportable segments	9,624	5,628	13,654	17,605	46,511	
Operating expenses (excluding depreciation and amortization)	1,143	2,977	12,126	5,720	21,966	
Operating margin (excluding depreciation and amortization)	8,481	2,651	1,528	11,885	24,545	(1)
Total assets (end of period)	75,304	102,730	16,071	126,670	320,775	
Nine months Ended September 30, 2010						
Service revenue						
Third party revenue	$ 14,777	$ 8,609	$ 31,297	$ 43,212	$ 97,895	
Related party revenue	14,759	650	228	—	15,637	
Total revenue for reportable segments	29,536	9,259	31,525	43,212	113,532	
Operating expenses (excluding depreciation and amortization)	2,888	7,772	30,318	16,236	57,214	
Operating margin (excluding depreciation and amortization)	26,648	1,487	1,207	26,976	56,318	(1)
Total assets (end of period)	77,359	71,455	18,223	128,919	295,956	
Nine months Ended September 30, 2011						
Service revenue						
Third party revenue	$ 8,316	$ 13,301	$ 32,634	$ 45,497	$ 99,748	
Related party revenue	20,748	3,401	7,228	—	31,377	
Total revenue for reportable segments	29,064	16,702	39,862	45,497	131,125	
	3,261	11,768	36,635	16,996	68,660	

Operating expenses (excluding depreciation and amortization)						
Operating margin (excluding depreciation and amortization)	25,803	4,934	3,227	28,501	62,465	(1)
Total assets (end of period)	75,304	102,730	16,071	126,670	320,775	

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

	Three Months Ended September 30,		Nine months Ended September 30,	
	2010	2011	2010	2011
Operating margin (excluding depreciation and amortization)	$ 19,930	$ 24,545	$ 56,318	$ 62,465
Depreciation and amortization	5,315	5,651	16,228	17,066
General and administrative expenses	3,883	4,679	11,037	14,065
Interest expense	13,530	9,120	39,502	27,284
Change in fair value of embedded derivative within convertible debt	—	(15,358)	—	(20,224)
Change in fair value of contingent dividends	—	(8,224)	—	(1,838)
Income (loss) before income taxes	$ (2,798)	$ 28,677	$ (10,449)	$ 26,112

13. COMMITMENTS AND CONTINGENCIES

The Partnership is subject to various legal actions and claims, including a securities class action and other lawsuits, an SEC investigation and a Grand Jury investigation due to events related to SemCorp's bankruptcy filings.

On May 3, 2011, the Partnership entered into a Stipulation of Settlement (the "Stipulation") to settle the consolidated securities class action litigation, In Re: SemGroup Energy Partners, L.P. Securities Litigation, Case No. 08-MD-1989-GKF-FHM (the "Class Action Litigation"), pending in the U.S. District Court for the Northern District of Oklahoma. As set forth more fully in the Stipulation, when given final approval by the court, among other things, the shareholder class will receive a total payment of approximately $28.0 million from the defendants. On June 9, 2011, the Court entered an order preliminarily approving, subject to further consideration at a settlement hearing, the proposed settlement pursuant to the Stipulation involving, among other things, a dismissal of the Class Action Litigation with prejudice. The Court held a hearing on October 5, 2011 and granted final approval of the proposed settlement and issued a final judgment (the "Judgment") in accordance with the Stipulation. The Judgment became final on November 7, 2011.

In the fourth quarter of 2010, the Partnership recorded a contingent loss of $20.2 million related to its portion of the settlement and a related insurance recovery receivable of $13.0 million. This contingent loss and insurance recovery receivable are reflected on the Partnership's balance sheet as of September 30, 2011. The net loss of $7.2 million attributable to this action was recognized in the fourth quarter of 2010. In June of 2011, the Partnership paid $0.5 million towards the settlement in escrow. This $0.5 million is reflected as a current asset on the Partnership's balance sheet as of September 30, 2011 and will be applied to the accrued settlement liability in October of 2011 as a result of the final approval of the proposed settlement. Pursuant to the Stipulation and the Judgment, on October 12, 2011, the Partnership issued and transferred 767,414 common units with a value equal to approximately $5.2 million to lead plaintiff's counsel in the Class Action Litigation. The transfer of the 767,414 common units is the final payment to the class by the Partnership required by the Stipulation and the Judgment. Furthermore, in October of 2011, the Partnership recognized the $13.0 million of insurance proceeds associated with the previously recorded insurance recovery receivable when the settlement was funded by the insurers. No parties admit any wrongdoing as part of the settlement.

On July 21, 2008, the Partnership received a letter from the staff of the Securities and Exchange Commission (the "SEC") giving notice that the SEC is conducting an inquiry relating to the Partnership and requesting, among other things, that the Partnership voluntarily preserve, retain and produce to the SEC certain documents and information relating primarily to the Partnership's disclosures respecting SemCorp's liquidity issues, which were the subject of the Partnership's July 17, 2008 press release. On October 21, 2008, the Partnership received a subpoena from the SEC pursuant to a formal order of investigation requesting certain documents relating to, among other things, SemCorp's liquidity issues. The Partnership received a subpoena from the SEC in connection with the investigation requesting that the Partnership produce additional documents by November 20, 2010 and additional documents were produced in January 2011. The Partnership has been cooperating, and intends to continue cooperating, with the SEC in its investigation. On October 18, 2011, the SEC announced that it had reached a settlement with Thomas L. Kivisto, a former member of the Board, with respect to certain asserted claims against Mr. Kivisto.

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 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 up to the net profits derived from the disputed pipelines. There has been no determination of the extent of potential damages for the Partnership's use of such 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 parties are engaged in discovery. The Partnership intends to vigorously defend these claims. No trial date has been set by the court.

In March and April 2009, nine current or former executives of SemCorp and certain of its affiliates filed wage claims with the Oklahoma Department of Labor against the Partnership's general partner. Their claims arise from the Partnership's general partner's Long-Term Incentive Plan, Employee Phantom Unit Agreement ("Phantom Unit Agreement"). Most claimants alleged that phantom units previously awarded to them vested upon the Change of Control that occurred in July 2008. One claimant alleged that his phantom units vested upon his termination. The claimants contended the Partnership's general partner's failure to deliver certificates for the phantom units within 60 days after vesting caused them to be damaged, and they sought recovery of approximately $2.0 million in damages and penalties. On April 30, 2009, all of the wage claims were dismissed on jurisdictional grounds by the Department of Labor.

On July 8, 2009, the nine executives filed suit against the Partnership's general partner in Tulsa County district court claiming they are entitled to recover the value of phantom units purportedly due them under the Phantom Unit Agreement. The claimants assert claims against the Partnership's general partner for alleged failure to pay wages and breach of contract and seek to recover the alleged value of units in the total amount of approximately $1.3 million, plus additional damages and attorneys' fees. The Partnership has distributed phantom units to certain of the claimants. On April 14, 2010, a Tulsa County district court judge ruled in favor of seven of the claimants, and awarded them approximately $1.0 million in damages. The Partnership has appealed this ruling. On October 22, 2010, the Partnership's general partner was ordered to pay $0.2 million in attorneys' fees. The Partnership has also appealed this order.

The Official Committee of Unsecured Creditors of SemCrude, L.P. ("Unsecured Creditors Committee") filed an adversary proceeding in connection with SemCorp's bankruptcy cases against Thomas L. Kivisto, Gregory C. Wallace, and Westback Purchasing Company, L.L.C. In that proceeding, filed February 18, 2009, the Unsecured Creditors Committee asserted various claims against the defendants on behalf of SemCorp's bankruptcy estate, including claims based upon theories of fraudulent transfer, breach of fiduciary duties, waste, breach of contract, and unjust enrichment. On June 8, 2009, the Unsecured Creditors Committee filed a Second Amended Complaint asserting additional claims against Kevin L. Foxx and Alex G. Stallings, among others, based upon certain findings and recommendations in the examiner's report. On October 6, 2009, a Third Amended Complaint was filed, and in December 2009, the Litigation Trust was substituted as the Plaintiff in the action. The claims in the Third Amended Complaint against Mr. Foxx and Mr. Stallings are based upon theories of fraudulent transfer, unjust enrichment, waste, breach of fiduciary duty, and breach of contract. Messrs. Foxx and Stallings moved to dismiss the claims against them.

On July 14, 2010, the Litigation Trust filed another adversary proceeding against Mr. Foxx, seeking to avoid certain transfers from SemCorp to Mr. Foxx and to bar Mr. Foxx from asserting claims in SemCorp's bankruptcy.

Messrs. Kivisto, Wallace, Cooper, Foxx and Stallings have reached an agreement with the Litigation Trust to settle the claims against them in the adversary proceedings described above. The agreement calls for the payment of $30 million to the Trust out of the proceeds of certain SemCorp insurance policies. In exchange, the Trust will provide a release of claims against Messrs. Kivisto, Wallace, Cooper, Foxx and Stallings. The court approved the settlement over an objection, which was subsequently appealed. The objector, the Trust, and Messrs. Kivisto, Wallace, Cooper, Foxx and Stallings reached an agreement to resolve that appeal on October 11, 2011. Pursuant to that agreement, the court dismissed the appeal, and the settlement became final, on October 26, 2011.

On July 24, 2009, the Partnership filed suit against Navigators Insurance Company ("Navigators") and Darwin National Assurance Company ("Darwin") in Tulsa County district court. In that suit, the Partnership is seeking a declaratory judgment that Darwin and Navigators did not have the right to rescind binders issued to the Partnership for three excess insurance policies in its Directors and Officers insurance program for the period from July 18, 2008 to July 18, 2009. The face amount of two of the policies was $10,000,000, and the face amount of the third policy was $5,000,000. The suit seeks a declaratory judgment that the binders were enforceable insurance contracts of Navigators and Darwin that have not been rescinded or cancelled. The suit also alleges that the attempted rescissions were in breach of contract and violated the duty of good faith and fair dealing, for which the Partnership is seeking the recovery of damages and attorneys' fees. This case has been temporarily stayed pursuant to the terms of a Settlement Agreement and Release (the "Settlement Agreement") between the Partnership, Navigators, and Darwin.
The Settlement Agreement was entered into as part of the settlement of the Class Action Litigation. The Court held a hearing on October 5, 2011 and granted final approval of the proposed Class Action Litigation settlement and issued the final Judgment in accordance with the Stipulation signed in the Class Action Litigation. Pursuant to the Stipulation, the Judgment became final on November 7, 2011. Pursuant to the Settlement Agreement, the Partnership will dismiss with prejudice the suit against Navigators and Darwin on or before November 17, 2011.

Koch Industries, Inc. (together with its subsidiaries, “Koch”), a previous owner of the Partnership’s asphalt facility located in Northumberland, Pennsylvania, has alleged that the Partnership has responsibility to assess the polychlorinated biphenyl (“PCB”) contamination at such facility although the contamination occurred prior to the Partnership becoming the owner of such facility. Koch claims that it was absolved of its responsibility to assess and clean up the site during SemCorp’s bankruptcy proceedings. The Partnership contends that Koch retained responsibility for such environmental issues and that SemCorp’s bankruptcy proceedings did not absolve Koch of these liabilities. On July 6, 2011, the Partnership filed an adversary complaint in connection with SemCorp’s bankruptcy cases against Koch seeking a declaration that SemCorp’s bankruptcy proceedings did not impact Koch’s responsibility to assess and clean the Northumberland site. A responsive pleading has been filed by Koch. The Partnership intends to vigorously defend against Koch’s allegation that the Partnership should be required to assess or clean up the PCB contamination.

On July 11, 2011, ExxonMobil filed suit against the Partnership in Harris County District Court, State of Texas, requesting damages in excess of $35,000 from the Partnership and other, third party service providers in connection with the relocation of existing pipelines of ExxonMobil and the Partnership. The Partnership has filed its answer to the claims and asserted cross-claims against third party service providers including the subcontractors of ExxonMobil. ExxonMobil had previously sent a settlement demand seeking approximately $1.9 million in damages. The Partnership intends to vigorously defend these claims.

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 not be covered by insurance.

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

The Partnership has contractual obligations to perform dismantlement and removal activities in the event that some of its asphalt product and residual fuel oil terminalling and storage assets are abandoned. These obligations include varying levels of activity including completely removing the assets and returning the land to its original state. The Partnership has determined that the settlement dates related to the retirement obligations are indeterminate. The assets with indeterminate settlement dates have been in existence for many years and with regular maintenance will continue to be in service for many years to come. Also, it is not possible to predict when demands for the Partnership’s terminalling and storage services will cease, and the Partnership does not believe that such demand will cease for the foreseeable future. Accordingly, the Partnership believes the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, the Partnership cannot reasonably estimate the fair value of the associated asset retirement obligations. Management believes that if the Partnership’s asset retirement obligations were settled in the foreseeable future the 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 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 and the tax credits and other items that give rise to significant portions of the deferred tax assets at September 30, 2011 are presented below (dollars in thousands):

Deferred tax assets	
Difference in bases of property, plant and equipment	$ 1,231,008
Net operating loss carryforwards	51,158
Deferred tax asset	1,282,166
Less: valuation allowance	(1,282,166)
Net deferred tax asset	$ —

Given the Partnership’s subsidiary taxed as a corporation has no earnings history to determine the likelihood of realizing the benefits of the deferred tax assets and the fact that the Partnership anticipates this subsidiary will generate net operating losses for the foreseeable future, the Partnership has provided a full valuation allowance against its deferred tax asset.

15. RECENTLY ISSUED ACCOUNTING STANDARDS

In January 2010, the FASB issued ASU 2010-06, “Improving Disclosures about Fair Value Measurements,” which requires separate disclosure of purchases, sales, issuances and settlements in the reconciliation of the Partnership’s Level 3 fair value measurements. The Partnership adopted this guidance with its March 31, 2011, Quarterly Report, and the impact was not material. Other provisions of ASU 2010-06 were adopted in 2010.

In May 2011, the FASB issued ASU 2011-04, “Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS),” which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and IFRS. This new guidance changes some fair value measurement principles and disclosure requirements. The Partnership is evaluating the impact of this guidance, which will be adopted beginning with the Partnership’s March 31, 2012, Quarterly Report.

In September 2011, the FASB issued ASU 2011-08, “Testing for Goodwill Impairment,” which allow an entity to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. Under these assessments, an entity would not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The Partnership is evaluating the impact of this guidance, and plans to adopt this guidance beginning with the Partnership’s December 31, 2011 annual impairment test.

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. (f/k/a/ SemGroup Energy Partners, L.P.), together with its subsidiaries, (2) our "General Partner" refers to Blueknight Energy Partners G.P., L.L.C. (f/k/a SemGroup Energy Partners G.P., L.L.C.), (3) "SemCorp" refers to SemGroup Corporation and its predecessors (including SemGroup, L.P.), subsidiaries and affiliates (other than our General Partner and us during periods in which we were affiliated with SemGroup, L.P.), (4) Vitol refers to Vitol Holding B.V., its affiliates and subsidiaries (other than our General Partner and us) and (5) 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, 2010, which was filed with the Securities and Exchange Commission (the "SEC") on March 16, 2011 (the "2010 Form 10-K").

Forward-Looking Statements

This report contains "forward-looking statements" within the meaning of the federal securities laws. 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," "conti 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 2010 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-three 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. Our common units, which represent limited partnership interests in our partnership, are listed on the NASDAQ Global Market. We were formed in February 2007 as a Delaware master limited partnership initially to own, operate and develop a diversified portfolio of complementary midstream energy assets.

Our Revenues

We have been pursuing opportunities to provide crude oil terminalling and storage services, crude oil pipeline services, crude oil trucking and producer field services and asphalt services to third parties. For the three months ended September 30, 2011, we derived approximately 24% of our revenues from services we provided to Vitol, with the remainder of our services being provided to third parties.

We have successfully increased the utilization of our Mid-Continent pipeline system, and throughput during the second quarter of 2011 reached effective capacity on segments of the system. While we see opportunity to increase the utilization of our crude oil trucking and producer field services assets due to high demand for our services in the markets we currently serve, demand outpaces supply for qualified drivers in this industry and is delaying our realization of complete utilization of these assets. We are actively pursuing additional drivers, and we anticipate increased utilization of these assets for the remainder of 2011. However, there can be no assurance that our efforts will be successful. Furthermore, effective August 1, 2011, we renegotiated the rates for the majority of our crude oil trucking services contracts, and have realized increased revenues in the third quarter of 2011 as a result.

We have long-term contracts in place for 43 of our 45 asphalt facilities. The majority of the leases and storage agreements related to these facilities have terms that expire at or near the end of 2016. 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.

We continue to pursue additional revenues with third parties and believe our gathering and transportation volumes have stabilized. We are aggressively pursuing incremental volumes for our systems; however, these additional efforts may not be successful. If we are unable to generate sufficient third party revenues, we will continue to experience lower volumes in our system 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, our results of operations and ability to conduct our business.

Our Expenses

Our maintenance expenditures are increasing due both to a tank inspection program that we implemented in the first quarter of 2011 in response to new regulation of the asphalt industry and to previously deferred maintenance of our crude oil pipeline systems. We currently anticipate maintenance capital expenditures to be approximately \$11.0 million to \$12.0 million in 2011, of which we have spent \$7.7 million as of September 30, 2011.

We experienced increased interest expenses and other costs due to the events of default that existed under our prior credit agreement and from entering into associated amendments to such prior credit agreement. In October of 2010, we entered into a new credit agreement and have experienced decreased interest expense in 2011 as a result. Please see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources” in the 2010 Form 10-K for a discussion of these agreements and the associated expenses.

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 and the net operating loss (“NOL”) carryforwards 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 taxed as a corporation has no earnings history to determine the likelihood of realizing the benefits of the deferred tax assets and the fact that we anticipate this subsidiary generating net operating losses for the foreseeable future, we have provided a full valuation allowance against our deferred tax asset as of September 30, 2011.

Recent Events

Global Transaction Agreement

On October 25, 2010 (the "Transaction Date"), we entered into a Global Transaction Agreement by and among us, our General Partner, Vitol and Charlesbank, pursuant to which we effected a refinancing of our existing debt. The Global Transaction Agreement contemplated three sets of transactions comprised of the Phase I Transactions, the Unitholder Vote Transactions, and the Phase II Transactions, each as defined in the Global Transaction Agreement. The Phase I Transactions were completed concurrently with the execution of the Global Transaction Agreement. For a detailed description of the Global Transaction Agreement, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations —Recent Events" in our 2010 Form 10-K.

On May 12, 2011, we, our General Partner, Vitol and Charlesbank entered into the First Amendment to Global Transaction Agreement (the "Amendment") pursuant to which the Unitholder Vote Transactions and the Phase II Transactions contemplated in the Global Transaction Agreement were modified.

Pursuant to the Global Transaction Agreement, as amended by the amendment, our General Partner has filed a definitive proxy statement with the Securities and Exchange Commission (the "SEC") relating to a special meeting (the "Unitholder Meeting") that was held on September 14, 2011 during which our unitholders considered and voted upon (i) certain amendments to our partnership agreement (the "Partnership Agreement Amendment Proposal") as more fully set forth below and (ii) an amendment to our General Partner's Long-Term Incentive Plan to increase the number of common units issuable under such plan by 1,350,000 common units from 1,250,000 common units to 2,600,000 common units (the "LTIP Proposal"). Pursuant to the Partnership Agreement Amendment Proposal, our partnership agreement would be amended to:

- reset (1) the minimum quarterly distribution to $0.11 per unit per quarter from $0.3125 per unit per quarter, (2) the first target distribution to $0.1265 per unit per quarter from $0.3594 per unit per quarter, (3) the second target distribution to $0.1375 per unit per quarter from $0.3906 per unit per quarter and (4) the third target distribution to $0.1825 per unit per quarter from $0.4688 per unit per quarter;

- waive the cumulative common unit arrearage;

- remove provisions in the partnership agreement relating to the subordinated units, including concepts such as a subordination period (and any provisions that expressly apply only during the subordination period) and common unit arrearage, in connection with the transfer to us, and our subsequent cancellation, of all of our outstanding subordinated units;

- provide that distributions shall not accrue or be paid to the holders of our incentive distribution rights for an eight quarter period beginning with the quarter in which the special meeting occurs;

- provide that during the period beginning on the date of this special meeting and ending on June 30, 2015 (the "Senior Security Restriction Period"), we will not issue any class or series of partnership securities that, with respect to distributions on such partnership securities or distributions upon liquidation of our partnership, ranks senior to the common units during the Senior Security Restriction Period, or "Senior Securities", without the consent of the holders of at least a majority of the outstanding common units (excluding the common units held by our General Partner and its affiliates and excluding any Senior Securities that are convertible into common units), subject to certain exceptions; and

- make certain other amendments relating to the conversion of our Series A Preferred Units (the “Preferred Units”).

On September 14, 2011, our unitholders approved the proposals outlined above. As a result, (i) our General Partner adopted the Fourth Amended and Restated Agreement of Limited Partnership of Blueknight Energy Partners, L.P. (the “Amended and Restated Partnership Agreement”) to reflect the approval of the Partnership Agreement Amendment Proposal, (ii) Vitol and Charlesbank transferred all of our outstanding subordinated units to us and we cancelled such subordinated units and (iii) we were obligated to undertake an approximately $77 million rights offering.

On October 3, 2011, we commenced the rights offering. Pursuant to the terms of the rights offering, we distributed to our common unitholders of record as of the close of business on September 27, 2011, 0.5412 rights for each outstanding common unit, with each whole right entitling the holder to acquire, for a subscription price of $6.50, a newly issued Preferred Unit. The rights offering expired on October 31, 2011.

The results of the rights offering indicate that the rights offering was over-subscribed and, accordingly, on November 8, 2011, we issued a total of 11,846,990 Preferred Units to unitholders that exercised their rights. We received net proceeds of approximately $77 million from the rights offering. The net proceeds from the rights offering, after deducting expenses, were used to redeem convertible debentures in the aggregate principal amount of $50 million plus accrued interest thereon that we issued to Vitol and Charlesbank and to repurchase an aggregrate of 3,225,494 Preferred Units from Vitol and Charlesbank. We expect that Preferred Units subscribed for in the rights offering will be mailed to participants or credited through DTC on or about Wednesday, November 9, 2011. In addition, we expect that the Preferred Units will begin trading on the NASDAQ Global Market on or about Thursday, November 10, 2011 under the symbol “BKEPP.”

Distributions

We have not made a distribution to our common unitholders or subordinated unitholders since May 15, 2008 due, in part, to the events of default that existed under our former credit agreement, restrictions under such credit agreement, and the uncertainty of our future cash flows relating to SemCorp’s bankruptcy filings. Our unitholders will be required to pay taxes on their share of our taxable income even though they did not receive a distribution for the quarters ended June 30, 2008 through March 31, 2011, and will not receive a distribution for the quarter ended September 30, 2011. Based on current estimates, management anticipates that it will recommend to our board of directors that we resume paying distributions on our common units beginning with the fourth quarter of 2011 (which distribution would be paid in the first quarter of 2012). However, there can be no assurance that such distribution will be paid. Due to the anticipated increase in spending on maintenance capital expenditures as well as legal and professional fees related to the refinancing, management will not recommend to our board of directors that we pay a distribution on our common units relating to the third quarter of 2011. The amount of distributions paid and the decision to make any distribution will be determined by our board of directors, which will have 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. As a result of the approval of the Partnership Agreement Amendment Proposal, the cumulative arrearage in minimum quarterly distributions was eliminated.

On October 24, 2011, the Board approved a distribution of $0.14 per Preferred Unit, or a total distribution of $3.0 million. We paid this distribution on the Preferred Units on November 7, 2011 to preferred unitholders of record as of October 30, 2011.

Results of Operations

The table below summarizes our financial results for the three and nine months ended September 30, 2010 and 2011:

	Three Months ended September 30, 2010	Three Months ended September 30, 2011	Nine months Ended September 30, 2010	Nine months Ended September 30, 2011
	(in thousands)			
Service revenues:				
Crude oil terminalling and storage revenues:				
Third party	$ 3,274	$ 2,941	$ 14,777	$ 8,316
Related party	6,393	6,683	14,759	20,748
Total crude oil terminalling and storage	9,667	9,624	29,536	29,064
Crude oil pipeline services revenues:				
Third party	2,702	4,408	8,609	13,301
Related party	394	1,220	650	3,401
Total crude oil pipeline services revenues	3,096	5,628	9,259	16,702
Crude oil trucking and producer field services revenues:				
Third party	10,331	10,170	31,297	32,634
Related Party	156	3,484	228	7,228
Total crude oil trucking and producer field services revenues	10,487	13,654	31,525	39,862
Asphalt services revenues:				
Third party	14,806	17,605	43,212	45,497
Related party	—	—	—	—
Total asphalt services	14,806	17,605	43,212	45,497
Total revenues	38,056	46,511	113,532	131,125
Operating expenses:				
Crude oil terminalling and storage	2,221	2,214	6,156	6,362
Crude oil pipelines services	3,147	4,199	9,921	15,402
Crude oil trucking and field services	10,194	12,418	32,048	37,835
Asphalt services	7,879	8,786	25,317	26,127
Total operating expenses	23,441	27,617	73,442	85,726
General and administrative expenses	3,883	4,679	11,037	14,065
Operating income:	10,732	14,215	29,053	31,334
Other (income) expense				
Interest expense	13,530	9,120	39,502	27,284
Change in fair value of embedded derivative within convertible debt	—	(15,358)	—	(20,224)
Change in fair value of rights offering liability	—	(8,224)	—	(1,838)
Income tax expense	50	72	151	219
Net income (loss)	$ (2,848)	$ 28,605	$ (10,600)	$ 25,893

Three Months Ended September 30, 2011 Compared to the Three Months Ended September 30, 2010

Service revenues. Service revenues include revenues from crude oil terminalling and storage services, crude oil pipeline services, crude oil trucking and producer field services and asphalt services. Service revenues, including reimbursement revenues for fuel and power, property tax, and insurance expenses related to the operations of our liquid asphalt facilities of $1.9 million and $1.8 million for the three months ended September 30, 2011 and 2010, respectively, were $46.5 million for the three months ended September 30, 2011, compared to $38.1 million for the three months ended September 30, 2010, an increase of $8.4 million, or 22%.

Crude oil terminalling and storage revenue was consistent at $9.6 million for the three months ended September 30, 2011 compared to $9.7 million for the three months ended September 30, 2010. We anticipate our crude oil terminalling and storage revenue for the remainder of 2011 will be consistent with the third quarter of 2011.

Crude oil pipeline services revenue increased by $2.5 million to $5.6 million for the three months ended September 30, 2011 compared to $3.1 million for the three months ended September 30, 2010. Revenues from the Eagle North pipeline system, which was placed in service in December 2010, account for $1.2 million of this increase. We also earned approximately $0.3 million of revenue related to reimbursed pipeline expense projects. The remaining increase in revenue is due to increased utilization of our assets, and throughput reached effective capacity on segments of our Mid-Continent system beginning in the second quarter of 2011.

Crude oil trucking and producer field services revenue increased by $3.2 million to $13.7 million for the three months ended September 30, 2011 compared to $10.5 million for the three months ended September 30, 2010. This increase is due to incremental revenues of $1.9 million attributed to the producer field services business we acquired in December of 2010. In addition, higher rates for the majority of our crude oil trucking service contracts became effective August 1, 2011.

Our asphalt services revenue, including reimbursement of fuel and power, property tax and insurance premiums, increased by $2.8 million to $17.6 million for the three months ended September 30, 2011 compared to $14.8 million for the three months ended September 30, 2010. This increase is primarily due to several of our customers exceeding throughput thresholds that triggered additional fees during the quarter. We anticipate fourth quarter throughput volumes to also surpass the thresholds, but not to the same extent as in the third quarter.

Operating expenses. Operating expenses increased by $4.2 million, or 18%, to $27.6 million for the three months ended September 30, 2011, compared to $23.4 million for the three months ended September 30, 2010. Crude oil terminalling and storage operating expenses of $2.2 million for the three months ended September 30, 2011 were consistent with operating expenses for the three months ended September 30, 2010. Our crude oil pipeline services operating expenses increased by $1.1 million to $4.2 million for the three months ended September 30, 2011, compared to $3.1 million for the three months ended September 30, 2010. Our crude oil trucking and producer field services operating expenses increased by $2.2 million to $12.4 million for the three months ended September 30, 2011, compared to $10.2 million for the three months ended September 30, 2010. Our asphalt operating expenses increased $0.9 million to $8.8 million for the three months ended September 30, 2011, compared to $7.9 million for the three months ended September 30, 2010.

Repair and maintenance expenses increased by $0.9 million to $3.2 million for the three months ended September 30, 2011. This increase was primarily to a tank inspection program that we implemented in the first quarter of 2011 in response to new regulation of the asphalt industry.

Salaries and wages increased by $1.5 million to $9.8 million for the three months ended September 30, 2011, compared to $8.3 million for the three months ended September 30, 2010, as we were in the process of transitioning away from services provided by SemCorp, establishing our operational management team and directly employing our own personnel throughout 2010 and the first six months of 2011. This transition was completed in the second quarter of 2011.

Furthermore, fuel expenses increased by $1.0 million to $2.8 million for the three months ended September 30, 2011 as compared to the third quarter of 2010. Partially offsetting operating expenses is the recognition of $1.1 million in gains on the sale of assets during the three months ended September 30, 2011.

General and administrative expenses. General and administrative expenses increased by $0.8 million, or 21%, to $4.7 million for the three months ended September 30, 2011, compared to $3.9 million for the three months ended September 30, 2010. This increase is primarily attributable to an increase in compensation expense to $2.3 million for the three months ended September 30, 2011 compared to $1.1 million for the three months ended September 30, 2010 due to an increase in our headcount as we transitioned away from SemCorp and established our operational management team. This was offset by a decrease in legal, financial advisory and other professional expenses of $0.4 million to $1.7 million for the three months ended September 30, 2011, compared to the three months ended September 30, 2010.

Interest expense. Interest expense represents interest on borrowings under our credit facility as well as amortization of debt issuance costs and the debt discount related to our Convertible Debentures. Interest expense decreased by $4.4 million to $9.1 million for the three months ended September 30, 2011 compared to $13.5 million for the three months ended September 30, 2010. Decreases in the weighted average interest rate of our credit facility and the weighted average debt outstanding due to the refinancing of our credit facility in October 2010 resulted in decreased interest expense of $10.9 million for the three months ended September 30, 2011 compared to the three months ended September 30, 2010. Also, as a result of the refinancing, amortization of our debt issuance costs decreased by $0.8 million for the three months ended September 30, 2011 when compared to the three months ended September 30, 2010. These decreases were partially offset by non-cash interest expense related to the Convertible Debentures, including the related debt discount, of $5.7 million for the three months ended September 30, 2011. The three months ended September 30, 2010 also include $1.5 million of capitalized interest whereas we did not capitalize any interest in the three months ended September 30, 2011.

Other (income) expense. Other income for the three months ended September 30, 2011 included an $8.2 million decrease in the fair value of the rights offering liability and a $15.4 million decrease in the fair value of the embedded derivative liability derived from the conversion option in the Convertible Debentures.

Nine months Ended September 30, 2011 Compared to the Nine months Ended September 30, 2010

Service revenues. Service revenues, including reimbursement revenues for fuel and power, property tax, and insurance expenses related to the operations of our liquid asphalt facilities of $5.4 million and $5.5 million for the nine months ended September 30, 2011 and 2010, respectively, were $131.1 million for the nine months ended September 30, 2011, compared to $113.5 million for the nine months ended September 30, 2010, an increase of $17.6 million, or 16%.

Crude oil terminalling and storage revenue decreased by $0.4 million to $29.1 million for the nine months ended September 30, 2011, compared to $29.5 million for the nine months ended September 30, 2010. We expect crude oil terminalling and storage revenue to remain consistent for the remainder of 2011.

Crude oil pipeline services revenue increased by $7.4 million to $16.7 million for the nine months ended September 30, 2011 compared to $9.3 million for the nine months ended September 30, 2010. Revenues from the Eagle North pipeline system, which was placed in service in December 2010, account for $2.8 million of this increase. We also earned $1.7 million in revenue related to reimbursed pipeline expense projects. The remaining increase in revenue is due to increased utilization of our assets, with throughput reaching effective capacity on segments of our Mid-Continent system during the second quarter of 2011.

Crude oil trucking and producer field services revenue increased by $8.4 million to $39.9 million for the nine months ended September 30, 2011 compared to $31.5 million for the nine months ended September 30, 2010. The majority of this increase is due to incremental revenues of $6.4 million attributed to the producer field services business we acquired in December of 2010. In addition, higher rates for the majority of our crude oil trucking service contracts became effective August 1, 2011.

Our asphalt services revenue increased by $2.3 million to $45.5 million for the nine months ended September 30, 2011, compared to $43.2 million for the nine months ended September 30, 2010. This revenue is inclusive of fuel reimbursement revenues related to fuel and power consumed to operate our asphalt facilities of $5.4 million and $5.5 million for the nine months ended September 30, 2011 and 2010, respectively. The increase in service revenues is primarily due to several of our customers exceeding throughput thresholds that triggered additional fees during the third quarter of 2011. We anticipate fourth quarter throughput volumes to also surpass the thresholds, but not to the same extent as in the third quarter.

Operating expenses. Operating expenses increased by $12.3 million, or 17%, to $85.7 million for the nine months ended September 30, 2011, compared to $73.4 million for the nine months ended September 30, 2010. Crude oil terminalling and storage operating expenses increased by $0.2 million to $6.4 million for the nine months ended September 30, 2011, compared to $6.2 million for the nine months ended September 30, 2010. Our crude oil pipeline services operating expenses increased by $5.5 million to $15.4 million for the nine months ended September 30, 2011 compared to $9.9 million for the nine months ended September 30, 2010. Our crude oil trucking and producer field services operating expenses increased by $5.8 million to $37.8 million for the nine months ended September 30, 2011, compared to $32.0 million for the nine months ended September 30, 2010. Our asphalt operating expenses increased by $0.8 million to $26.1 million for the nine months ended September 30, 2011 compared to $25.3 million for the nine months ended September 30, 2010.

Compensation expense increased by $4.4 million to $29.0 million for the nine months ended September 30, 2011 as compared to $24.6 million for the nine months ended September 30, 2010. This increase is a result of directly employing our own personnel as we transitioned away from the services provided by SemCorp under a shared services agreement. We completed this transition in the second quarter of 2011.

Repair and maintenance expenses increased by $4.5 million to $10.9 million for the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010 due to both a tank inspection program that we implemented in the first quarter of 2011 in response to new regulation of the asphalt industry and previously deferred maintenance of our crude oil pipeline systems. Approximately $1.7 million of the repair and maintenance expense in the nine months ended September 30, 2011 is offset by reimbursed pipeline expense projects reflected as revenue in our statement of operations. Included in the repair and maintenance expense for the nine months ended September 30, 2011 is $1.4 million of expenses associated with leaks that occurred on our pipeline systems.

In addition, fuel expense increased $2.8 million to $8.3 million for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 due primarily to increased prices. Operating expenses for the nine months ended September 30, 2010 include a $0.8 million impairment charge related to an asphalt facility located in Morehead City, North Carolina that we sold in April of 2010. Partially offsetting operating expenses is the recognition of $1.9 million in gains on the sale of assets during the nine months ended September 30, 2011 in connection with the disposal and replacement of depreciated assets.

General and administrative expenses. General and administrative expenses increased by $3.1 million, or 28%, to $14.1 million for the nine months ended September 30, 2011 compared to $11.0 million for the nine months ended September 30, 2010. This increase is primarily attributable to an increase in compensation expense of $3.5 million to $6.9 million for the nine months ended September 30, 2011 compared to $3.4 million for the nine months ended September 30, 2010 due to an increase in our headcount as we transitioned away from SemCorp and established our operational management team. This was offset by a decrease in legal, financial advisory and other professional expenses of $0.7 million to $5.1 million for the nine months ended September 30, 2011, compared to the nine months ended September 30, 2010.

Interest expense. Interest expense represents interest on borrowings under our credit facility as well as amortization of debt issuance costs and the debt discount related to our Convertible Debentures. Total interest expense of $27.3 million for the nine months ended September 30, 2011 decreased by $12.2 million compared to total interest expense of $39.5 million for the nine months ended September 30, 2010. Decreases in the weighted average interest rate of our credit facility and the weighted average debt outstanding due to the refinancing of our credit facility in October 2010 resulted in decreased interest expense of $30.2 million for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. Also, in relation to the refinancing, amortization of our debt issuance costs decreased by $2.2 million for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. These decreases were partially offset by non-cash interest expense related to the Convertible Debentures, including the related debt discount, of $17.1 million for the nine months ended September 30, 2011. The nine months ended September 30, 2010 also included $2.8 million of capitalized interest whereas we did not capitalize any interest in the nine months ended September 30, 2011. We also incurred $0.6 million in related party interest related to the ENPS Throughput Agreement for the nine months ended September 30, 2011 compared to $0.1 million for the nine months ended September 30, 2010.

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.

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, 2010 and 2011:

	Nine months Ended September 30,	
	2010	2011

	(in millions)			
Net cash provided by operating activities	$	16.5	$	31.8
Net cash used in investing activities		(9.7)		(11.6)
Net cash used in financing activities		(10.3)		(24.0)

Operating Activities. Net cash provided by operating activities was $31.8 million for the nine months ended September 30, 2011, as compared to the $16.5 million for the nine months ended September 30, 2010. The increase in net cash provided by operating activities is primarily due to an increase in net income to $25.9 million for the nine months ended September 30, 2011 from a net loss of $10.6 million for the nine months ended September 30, 2010. The increase in net income was primarily the result of lower interest expense as a result of the refinancing of our debt in the fourth quarter of 2010 and unrealized gains associated with the change in the estimated fair value of both the embedded derivative within the Convertible Debentures and the rights offering liability.

Investing Activities. Net cash used in investing activities was $11.6 million for the nine months ended September 30, 2011, as compared to the $9.7 million for the nine months ended September 30, 2010. The change in cash used in investing activities is primarily due to an increase in capital expenditures.

Financing Activities. Net cash used in financing activities was $24.0 million for the nine months ended September 30, 2011, as compared to $10.3 million for the nine months ended September 30, 2010. Net cash used in financing activities for the nine months ended September 30, 2011 is primarily comprised of $8.3 million of distributions to holders of our Preferred Units and net repayments on long term debt of $14.7 million.

Our Liquidity and Capital Resources

Cash flow from operations and our credit facility are our primary sources of liquidity. At September 30, 2011, we had approximately $68.3 million of availability under our revolving credit facility. At September 30, 2011, we had a working capital deficit of $69.9 million. This is primarily a function of both the $44.9 million of Convertible Debentures, which we redeemed with the use of proceeds from the rights offering, and our approach to cash management. On April 5, 2011, our revolving credit facility was increased from $75.0 million to $95.0 million. As of November 7, 2011, we have aggregate unused credit availability under our revolving credit facility of approximately $72.3 million and cash on hand of approximately $1.8 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 $6.0 million in the nine months ended September 30, 2011, compared to $7.4 million in the nine months ended September 30, 2010. We expect expansion capital expenditures for organic growth projects to be approximately $7.0 million to $8.0 million in 2011. Maintenance capital expenditures totaled $7.7 million in the nine months ended September 30, 2011 compared to $4.2 million in the three months ended September 30, 2010. We expect maintenance capital expenditures to be approximately $11.0 million to $12.0 million in 2011.

Our Ability to Grow Depends on Our Ability to Access External Expansion Capital. Our partnership agreement provides 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 expect that substantially all of our cash generated from operations will be used to reduce our debt or pay distributions. Accordingly, 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 October 25, 2010, we entered into a new credit agreement, which we refer to as our credit agreement. Our credit agreement includes a $200.0 million term loan facility and a revolving loan facility. On April 5, 2011, the revolving loan facility was increased from $75.0 million to $95.0 million. Vitol is a lender under our credit agreement and has committed to loan us $15.0 million pursuant to such agreement. The entire amount of the term loan and approximately $43.9 million of the revolver was drawn on October 25, 2010 in connection with repaying all existing indebtedness under our prior credit agreement. The proceeds of loans made under our credit agreement may be used for working capital and other general corporate purposes.

The 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.

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 $200.0 million for all revolving loan commitments under our credit agreement.

The credit agreement will mature on October 25, 2014, 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 of certain asset sales, casualty events and debt incurrences, and, in certain circumstances, with a portion of our excess cash flow (as defined in the credit agreement). These mandatory prepayments will be applied to the term loan under our credit agreement until it is repaid in full, then applied to reduce commitments under the revolving loan facility.

Until May 15, 2011, borrowings under our credit agreement bore interest, at our option, at either (i) the ABR (the highest of the administrative agent's prime rate, the federal funds rate plus 0.5%, or the one-month eurodollar rate (as defined in the credit agreement) plus 1%), plus an applicable margin of 3.25%, or (ii) the eurodollar rate plus an applicable margin of 4.25%. After May 15, 2011, the applicable margin for loans accruing interest based on the ABR ranges from 3.0% to 3.5%, and the applicable margin for loans accruing interest based on the eurodollar rate ranges from 4.0% to 4.5%, in each case depending on our consolidated total leverage ratio (as defined in the credit agreement). 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 of 0.50% per annum on the unused availability under the credit agreement. The credit agreement does not have a floor for the ABR or the eurodollar rate. In connection with entering into our credit agreement, we paid certain upfront fees to the lenders thereunder, and we paid certain arrangement and other fees to the arranger and administrative agent of our credit agreement. Vitol received its pro rata portion of such fees as a lender under our credit agreement. During the three months ended September 30, 2011, our weighted average interest rate under the credit agreement was 4.6% and our total weighted average interest rate, including interest under our Convertible Debentures and the throughput capacity agreement with Vitol related to our Eagle North pipeline system was 12.4%, resulting in interest expense of approximately $9.1 million.

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 (except for the consolidated interest coverage ratio, which builds to a four-quarter test).

The maximum permitted consolidated total leverage ratio is as follows:

- 4.75 to 1.00 for the fiscal quarters ending September 30, 2011 and December 31, 2011; and
- 4.50 to 1.00 for the fiscal quarter ending March 31, 2012 and each fiscal quarter thereafter.

The minimum permitted consolidated interest coverage ratio (as defined in the credit agreement) is 3.00 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

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 partnership's equity, make distributions to unitholder and make certain other restricted payments;
- make investments;
- modify the terms of the Convertible Debentures and certain other 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, 2011, our leverage ratio was 3.76 to 1.00 and the interest coverage ratio was 5.01 to 1.00. We were in compliance with all covenants of our credit agreement as of September 30, 2011.

The credit agreement permits us to make quarterly distributions of available cash (as defined in our partnership agreement) to unitholders so long as: (i) no default or event of default exists under our credit agreement, (ii) we have, on a pro forma basis after giving effect to such distribution, at least $10.0 million of availability under the revolving loan facility, and (iii) our consolidated total leverage ratio, on a pro forma basis, would not be greater than (x) 4.25 to 1.00 for the fiscal quarters ending September 30, 2011 and December 31, 2011, or (y) 4.00 to 1.00 for any fiscal quarter ending on or after March 31, 2012. We are currently allowed to make distributions to our unitholders in accordance with these covenants; however, we will only make distributions to the extent we have sufficient cash from operations after establishment of cash reserves as determined by our 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;
- our, or any of our subsidiaries', default under other indebtedness that exceeds a threshold amount;
- judgments against us or any of our subsidiaries, in excess of a threshold amount;
- certain ERISA events involving us or any of our subsidiaries, in excess of a threshold amount;
-

bankruptcy or other insolvency events involving us or any of our subsidiaries; and

- a change in control (as defined in the credit agreement).

If an event of default relating to bankruptcy or other insolvency events occurs, all indebtedness 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 the credit agreement, or if we are unable to make any of the representations and warranties in the credit agreement, we will be unable to borrow funds or have letters of credit issued under the credit agreement.

It will constitute a change of control under our credit agreement if either Vitol or Charlesbank ceases to own, directly or indirectly, exactly 50% of the membership interests of our general partner or if our general partner ceases to be controlled by both Vitol and Charlesbank.

Convertible Debentures.   In connection with the Global Transaction Agreement, we issued and sold the Convertible Debentures to Vitol and Charlesbank for $25 million each, resulting in gross proceeds to us of $50 million. On Novembe 9, 2011, we redeemed the Convertible Debentures with proceeds from our rights offering. Our obligations under the Convertible Debentures were subordinate to our obligations under our credit agreement. The Convertible Debentures bore interest at 10% until October 25, 2011. After such time, the Convertible Debentures bore interest at 12%. Interest could only be paid in cash with the proceeds from an equity offering. Each Convertible Debenture was redeemable in whole or in part by us at any time prior to December 31, 2011 at a price equal to $25 million plus any accrued and unpaid interest, but our credit agreement provides that any such redemption may only be made with the proceeds from an equity offering, such as the rights offering. If not otherwise redeemed, the Convertible Debentures would have matured on December 31, 2011 and, on such date, all outstanding principal and any accrued and unpaid interest would have automatically converted into Preferred Units. The number of Preferred Units issuable on conversion of the Convertible Debentures would have been an amount equal to (i) the sum of the outstanding principal and any accrued and unpaid interest being converted, divided by (ii) 6.50.

Contractual Obligations. A summary of our contractual cash obligations over the next several fiscal years, as of September 30, 2011, 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)	$ 258.2	$ 10.5	$ 21.0	$ 226.7	$ —
Convertible Debentures(2)	49.7	49.7	—	—	—
Operating lease obligations	9.8	4.2	4.5	0.7	0.4
Related party Throughput Capacity Agreement(3)	5.7	2.2	3.3	0.2	—
Non-compete agreement(4)	0.2	0.1	0.1	—	—

(1) Represents required future principal repayments of borrowings of $226.0 million and variable rate interest payments of $32.2 million. At September 30, 2011, our borrowings had an interest rate of approximately 4.49%. This interest rate was used to calculate future interest payments. All amounts outstanding under the credit facility mature in October 2014.

(2) Represents $44.9 million in outstanding Convertible Debentures and $4.8 million of accrued and unpaid interest as of September 30, 2011. The Convertible Debentures mature on December 31, 2011 and, on such date, all outstanding principal and any accrued and unpaid interest automatically converts into Preferred Units. The Convertible Debentures were redeemed on November 9, 2011.

(3) Represents required future repayments of the Vitol prepaid fee related to the throughput capacity agreement for our Eagle North pipeline system of $4.7 million and interest of $1.0 million. This agreement matures at December 31, 2014.

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

Recent Accounting Pronouncements

For information regarding recent accounting developments that may affect our future financial statements, see Note 15 of the Notes to Unaudited Consolidated Financial Statements included in Part I, Item I of this quarterly support.

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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 November 7, 2011 we had $222.7 million outstanding under our credit facility that was subject to a variable interest rate. Until May 15, 2011, borrowings under our credit agreement bore interest, at our option, at either (i) the ABR (the highest of the administrative agent's prime rate, the federal funds rate plus 0.5%, or the one-month eurodollar rate (as defined in the credit agreement) plus 1%), plus an applicable margin of 3.25%, or (ii) the eurodollar rate plus an applicable margin of 4.25%. After May 15, 2011, the applicable margin for loans accruing interest based on the ABR ranges from 3.0% to 3.5%, and the applicable margin for loans accruing interest based on the eurodollar rate ranges from 4.0% to 4.5%, in each case depending on our consolidated total leverage ratio (as defined in the credit agreement).

During the three months ended September 30, 2011, the weighted average interest rate under the credit agreement incurred by us was 4.6% and the total weighted average interest rate, including interest associated with the Convertible Debentures and the throughput capacity agreement with Vitol related to our Eagle North pipeline system, was 12.4% resulting in interest expense of approximately $9.1 million.

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. Additionally, if domestic interest rates continue to increase, the interest rates on any of our future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Based on borrowings as of September 30, 2011 and the terms of our credit agreement, an increase or decrease of 100 basis points in the interest rate will result in increased or decreased annual interest expense of approximately $2.3 million.

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, 2011, 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, 2011 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

For a discussion of certain litigation and similar proceedings, please refer to Note 13, "Commitments and Contingencies," of the Notes to Unaudited Consolidated Financial Statements, which is incorporated by reference herein.

Item 1A. Risk Factors

The risk factor set forth in "Part II, Item 1A. Risk Factors" in our Quarterly Report on Form 10-Q for the period ending March 31, 2011, which updated the corresponding risk factor in "Part I, Item 1A. Risk Factors" in our 2010 Form 10-K, regarding the relisting of our common units on the NASDAQ Global Market, is no longer applicable. Our common units were relisted on the NASDAQ Global Market effective May 16, 2011.

In addition, with the completion of our rights offering, we expect our Preferred Units will begin trading on the NASDAQ Global Market on or about Thursday, November 10, 2011 under the symbol "BKEPP." The following risk factors relate to the Preferred Units.

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to make cash distributions to holders of our Preferred Units at the preference distribution rate.

In order to make cash distributions on our Preferred Units at the preference distribution rate of $0.17875 per unit per quarter, or $0.715 per unit per year, we will require available cash of approximately $5.4 million per quarter, or $21.5 million per year, assuming that this rights offering is subscribed in full. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions on our Preferred Units at the preference rate. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things, the risks described in our 2010 Form 10-K.

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

- the level of capital expenditures we make;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our credit facility or other debt agreements; and
- the amount of cash reserves established by our general partner.

The conversion rate applicable to the Preferred Units will not be adjusted for all events that may be dilutive.

The number of our common units issuable upon conversion of the Preferred Units is subject to adjustment only for subdivisions, splits or certain combinations of our common units. The number of common units issuable upon conversion is not subject to adjustment for other events, such as employee option grants, offerings of our common units for cash or in connection with acquisitions or other transactions that may increase the number of outstanding common units and dilute the ownership of existing common unitholders. The terms of the Preferred Units do not restrict our ability to offer common units in the future or to engage in other transactions that could dilute our common units.

We have rights to require our preferred unitholders to convert their Preferred Units into common units, and we may exercise this mandatory conversion right at an undesirable time.

We have the right in certain circumstances, including if a certain number of Preferred Units are converted to common units or if certain distribution levels or trading price levels on the common units are reached, to force the conversion of all outstanding Preferred Units to common units. At the closing of this rights offering, Vitol and Charlesbank, the owners of our general partner, will own enough Preferred Units such that if they converted all of them to common units, we could then force all remaining outstanding Preferred Units to convert to common units. As a result, our preferred unitholders may be required to convert their Preferred Units at an undesirable time and may not receive their expected return on investment.

Holders of the Preferred Units will not have rights to distributions as holders of common units until they acquire our common units.

Until our preferred unitholders acquire common units upon conversion of the Preferred Units, such preferred unitholders will have no rights with respect to distributions on our common units. Upon conversion, our preferred unitholders will be entitled to exercise the rights of a holder of our common units only as to matters for which the record date occurs after the date on which such Preferred Units were converted to our common units.

The Preferred Units are limited partner interests in our partnership and therefore are subordinate to any indebtedness.

The Preferred Units are limited partner interests in our partnership and do not constitute indebtedness. As such, the Preferred Units will rank junior to all indebtedness and other non-equity claims on our partnership with respect to assets available to satisfy claims on our partnership, including in a liquidation of our partnership.

Holders of our Preferred Units and common units have limited voting rights and are not entitled to elect our General Partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or the Board, and have no right to elect our general partner or the Board on an annual or other continuing basis. The Board is chosen by Vitol and Charlesbank. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. Amendments to our partnership agreement may be proposed only by or with the consent of our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our Preferred Units or common units are dissatisfied, they cannot initially remove our general partner without its consent.

Our unitholders will be unable initially to remove our general partner without its consent because our general partner and its affiliates will own a sufficient number of units upon completion of this rights offering to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove the general partner. After we close the rights offering, we expect that Vitol and Charlesbank will collectively own approximately 35% of our aggregate outstanding Preferred Units and common units.

Our partnership agreement restricts the voting rights of unitholders, other than our General Partner and its affiliates, including Vitol and Charlesbank, owning 20% or more of any class of our Partnership Securities.

Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the Board, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions.

Affiliates of our General Partner may sell Preferred Units in the public markets, which sales could have an adverse impact on the trading price of the Preferred Units.

We expect that after we close the rights offering, Vitol and Charlesbank will collectively own approximately 18.3 million Preferred Units. The sale of these units in the public markets could have an adverse impact on the price of the

Preferred Units or on any trading market that may develop.

Our general partner has a limited call right that may require our preferred unitholders to sell their Preferred Units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the Preferred Units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the Preferred Units held by unaffiliated persons at a price not less than their then-current market price. As a result, our preferred unitholders may be required to sell their Preferred Units at an undesirable time or price and may not receive any return on their investment. Our preferred unitholders also may incur a tax liability upon a sale of their units. After the closing of the rights offering, we expect that our general partner and its affiliates will own approximately 61% of the Preferred Units.

There is currently no established public trading market for the Preferred Units and our preferred unitholders' investment may be illiquid for an indefinite amount of time.

There is currently no market for the Preferred Units. The Preferred Units have been approved for listing on Nasdaq under the symbol "BKEPP" and we expect trading to begin on November 10, 2011. The continuing listing of the Preferred Units on Nasdaq will depend upon the Preferred Units continuing to meet Nasdaq's listing standards. Furthermore, there is no assurance that an active trading market for the Preferred Units will develop or, if developed, be maintained. As a result, we cannot provide any assurance about the price at which our preferred unitholders will be able to sell the Preferred Units, or about whether our preferred unitholders will be able to sell such units at all, and our preferred unitholders might be unable to sell their Preferred Units at a price equal to, or higher than, the subscription price, if at all. Any market price for the Preferred Units that may develop will be subject to significant fluctuation in response to the depth and liquidity of the market for the Preferred Units, variations in our quarterly and annual operating results, developments affecting our business, general trends in our industry, actions taken by competitors, investor perception, the overall performance of the stock market, general economic and market conditions, and other factors.

Furthermore, since the Preferred Units do not have a maturity date and is not redeemable at our preferred unitholders' option, our preferred unitholders may, unless they convert their Preferred Units into common units (or our partnership forces the conversion of such Preferred Units into common units), be required to hold their Preferred Units indefinitely if they are unable to sell the Preferred Units on terms acceptable to such preferred unitholders.

The price of our common units, and therefore of the Preferred Units, may fluctuate significantly, which may make it difficult for our preferred unitholders to resell the Preferred Units, or common units issuable upon conversion thereof, when our preferred unitholders want or at prices they find attractive.

The price of our common units on Nasdaq has historically fluctuated significantly. We expect that the market price of our common units will continue to fluctuate. Because the Preferred Units are convertible into common units, volatility or depressed prices for our common units could have a similar effect on the trading price of the Preferred Units. Holders who receive common units pursuant to the terms of the Preferred Units will also be subject to the risk of volatility and depressed prices.

Market interest rates may affect the value of our convertible preferred stock.

One of the factors that will influence the price of our Preferred Units will be the distribution yield on our Preferred Units relative to market interest rates. An increase in market interest rates could cause the market price of the Preferred Units to go down. The trading price of the Preferred Units will also depend on many other factors, which may change from time to time, including:

- the market for similar securities;
- government action or regulation;
- general economic conditions or conditions in the financial markets; and
- our financial condition, performance and prospects.

Upon conversion of Preferred Units to common units, preferred unitholders could under certain limited circumstances receive a gross income allocation that may materially increase the taxable income allocated to such preferred unitholders.

Under our partnership agreement and in accordance with proposed Treasury Regulations, immediately after the conversion of a Preferred Unit, we will adjust the capital accounts of all of our partners to reflect any positive difference (“Unrealized Gain”) or negative difference (“Unrealized Loss”) between the fair market value and the carrying value of our assets at such time as if such Unrealized Gain or Unrealized Loss had been recognized on an actual sale of each such asset for an amount equal to its fair market value at the time of such conversion. Such Unrealized Gain or Unrealized Loss (or items thereof) will be allocated first to the preferred unitholder in respect of common units received upon the conversion until the capital account of each such common unit is equal to the per unit capital account for each existing common unit. This allocation of Unrealized Gain or Unrealized Loss will not be taxable to the preferred unitholder or to any other unitholders. If the Unrealized Gain or Unrealized Loss allocated as a result of the conversion of a Preferred Unit is not sufficient to cause the capital account of each common unit received upon such conversion to equal the per unit capital account for each existing common unit, then capital account balances will be reallocated among the unitholders as needed to produce this result. In the event that such a reallocation is needed, a preferred unitholder would be allocated taxable gross income in an amount equal to the amount of any such reallocation to it.

Item 5. Other Information

On November 9, 2011, we issued 11,846,990 Preferred Units to the unitholders that exercised their rights in the rights offering and received gross proceeds of approximately $77 million related thereto. Approximately 96% of basic subscription rights were exercised, leaving approximately 470,000 Preferred Units available to fulfill over-subscriptions. Because over-subscription requests exceeded the number of Preferred Units available for subscription, the subscription agent allocated the Preferred Units available pursuant to over-subscription rights in accordance with the procedures described in the prospectus supplement dated September 27, 2011. Preferred Units subscribed for were distributed to record holders, including DTC. The Partnership expects DTC to credit the accounts of DTC participants on or about Wednesday, November 9, 2011. The Preferred Units are expected to begin trading on the NASDAQ Global Market on or about Thursday, November 10, 2011 under the symbol “BKEPP.” As set forth in more detail below, we used the net proceeds received from the rights offering, after deducting expenses, to redeem the Convertible Debentures and to repurchase an aggregate of 3,225,494 Preferred Units from Vitol and Charlesbank.

On November 8, 2011, we delivered notices of redemption to Vitol and Charlesbank indicating our intent to redeem the Convertible Debentures on November 9, 2011. In accordance with the redemption notices, on November 9, 2011, we redeemed both of the Convertible Debentures at a redemption price of 100 percent of the principal amount outstanding plus unpaid interest accrued prior to November 9, 2011, or a total of approximately $55.2 million. We originally issued and sold the Convertible Debentures in connection with the refinancing of our debt in October 2010.

On November 9, 2011, we repurchased 1,612,747 Preferred Units from each of Vitol and Charlesbank, or an aggregate of 3,225,494 repurchased Preferred Units, for which we paid an aggregate purchase price of approximately $21.2 million. Such repurchase was made with proceeds from the rights offering and in accordance with the Global Transaction Agreement, as amended by the Amendment. Following the issuance of the Preferred Units in connection with the rights offering and our repurchase of the Preferred Units from Vitol and Charlesbank, there are 30,159,958 Preferred Units outstanding.

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 9, 2011	By:	/s/ Alex G. Stallings Alex G. Stallings Chief Financial Officer and Secretary
Date: November 9, 2011	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 October 25, 2010 (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).
4.1	Specimen Common Unit Certificate (included in Exhibit 3.2).
4.2	Specimen Series A Preferred Unit Certificate (filed as Exhibit 4.3 to the Partnership's Current Report on Form 8-K, filed September 27, 2011, and incorporated herein by reference).
4.3	Specimen Right Certificate (filed as Exhibit 4.2 to the Partnership's Current Report on Form 8-K, filed September 27, 2011, and incorporated herein by reference).
4.4	Rights Agent Agreement, dated as of September 27, 2011, between Blueknight Energy Partners, L.P. and American Stock Transfer & Trust Company, LLC, as rights agent (filed as Exhibit 4.1 to the Partnership's Current Report on Form 8-K, filed September 27, 2011, and incorporated herein by reference).
10.1	Consulting Services Agreement, dated August 17, 2011 to be effective as of July 1, 2011, by and between BKEP Pipeline, L.L.C. and Vitol Midstream LLC (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed August 18, 2011, and incorporated herein by reference).
10.2	Operating and Maintenance Agreement, dated August 17, 2011 to be effective as of July 1, 2011, by and between BKEP Pipeline, L.L.C. and Vitol Midstream LLC (filed as Exhibit 10.2 to the Partnership's Current Report on Form 8-K, filed August 18, 2011, and incorporated herein by reference).
10.3	Blueknight Energy Partners G.P., L.L.C. Long-Term Incentive Plan (as amended and restated effective June 9, 2011) (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed September 14, 2011, 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."

* Filed herewith.