Sprague Resources LP
Form 10-Q
November 07, 2016
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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, 2016
or
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period to
Commission file number: 001-36137

Sprague Resources LP
(Exact name of registrant as specified in its charter)

Delaware	45-2637964
(State of incorporation)	(I.R.S. Employer Identification No.)

185 International Drive
Portsmouth, New Hampshire 03801
(Address of principal executive offices)
Registrant's telephone number, including area code: (800) 225-1560

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

Indicated 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 Regulations S-T 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

The registrant had 11,241,851 common units and 10,071,970 subordinated units outstanding as of November 1, 2016.

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Part I – FINANCIAL INFORMATION
Item 1 — Condensed Consolidated Financial Statements
Sprague Resources LP
Condensed Consolidated Balance Sheets
(in thousands except units)

	September 30, 2016 (Unaudited)	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$ 3,449	$ 30,974
Accounts receivable, net	133,321	160,848
Inventories	266,728	241,320
Fair value of derivative assets	98,299	157,714
Other current assets	46,200	57,006
Total current assets	547,997	647,862
Property, plant and equipment, net	250,713	250,909
Intangibles, net	24,676	22,113
Other assets, net	14,926	16,160
Goodwill	70,550	63,288
Total assets	$ 908,862	$ 1,000,332
Liabilities and unitholders' equity		
Current liabilities:		
Accounts payable	$ 63,307	$ 91,387
Accrued liabilities	42,571	47,840
Fair value of derivative liabilities	58,533	37,178
Due to General Partner	7,573	14,021
Current portion of working capital facilities	196,851	332,500
Current portion of capital leases and other debt	1,424	1,213
Total current liabilities	370,259	524,139
Working capital facilities - less current portion	104,561	—
Acquisition facility	262,400	283,400
Capital leases and other debt - less current portion	4,480	3,987
Other liabilities	14,637	14,995
Due to General Partner	1,194	1,264
Deferred income taxes	14,999	15,062
Total liabilities	772,530	842,847
Commitments and contingencies (Note 9)		
Unitholders' equity:		
Common unitholders - public (9,197,649 units and 8,977,378 units issued and outstanding, as of September 30, 2016 and December 31, 2015, respectively)	180,732	189,483
Common unitholders - affiliated (2,034,378 units issued and outstanding)	(3,325)	(1,370)
Subordinated unitholders - affiliated (10,071,970 units issued and outstanding)	(28,669)	(18,989)
Accumulated other comprehensive loss, net of tax	(12,406)	(11,639)
Total unitholders' equity	136,332	157,485
Total liabilities and unitholders' equity	$ 908,862	$ 1,000,332

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

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Sprague Resources LP
Unaudited Condensed Consolidated Statements of Operations
(in thousands except unit and per unit amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net sales	$422,779	$558,022	$1,623,173	$2,818,123
Cost of products sold (exclusive of depreciation and amortization)	383,211	498,537	1,463,938	2,604,969
Operating expenses	15,725	17,870	49,078	54,394
Selling, general and administrative	19,735	19,894	62,099	71,193
Depreciation and amortization	5,329	5,188	16,001	15,365
Total operating costs and expenses	424,000	541,489	1,591,116	2,745,921
Operating (loss) income	(1,221)	16,533	32,057	72,202
Other (expense) income	(19)	—	(114)	514
Interest income	40	138	379	367
Interest expense	(6,685)	(6,399)	(20,179)	(20,624)
(Loss) income before income taxes	(7,885)	10,272	12,143	52,459
Income tax provision	(909)	(1,692)	(861)	(2,490)
Net (loss) income	(8,794)	8,580	11,282	49,969
Incentive distributions declared	(488)	(105)	(1,144)	(154)
Limited partners’ interest in net (loss) income	$(9,282)	$8,475	$10,138	$49,815
Net (loss) income per limited partner unit:				
Common - basic	$(0.44)	$0.40	$0.48	$2.37
Common - diluted	$(0.44)	$0.39	$0.46	$2.32
Subordinated - basic and diluted	$(0.44)	$0.40	$0.48	$2.37
Units used to compute net (loss) income per limited partner unit:				
Common - basic	11,229,805	10,999,848	11,189,987	10,965,400
Common - diluted	11,229,805	11,253,395	11,506,830	11,199,128
Subordinated - basic and diluted	10,071,970	10,071,970	10,071,970	10,071,970
Distribution declared per common and subordinated units	$0.5625	$0.5025	$1.6425	$1.4625

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

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Sprague Resources LP
Unaudited Condensed Consolidated Statements of Comprehensive (Loss) Income
(in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net (loss) income	$(8,794)	$8,580	$11,282	$49,969
Other comprehensive loss, net of tax:				
Unrealized gain (loss) on interest rate swaps				
Net gain (loss) arising in the period	460	(428)	(1,176)	(1,388)
Reclassification adjustment related to losses realized in income	384	126	1,182	384
Net change in unrealized gain (loss) on interest rate swaps	844	(302)	6	(1,004)
Tax effect	(15)	8	—	29
	829	(294)	6	(975)
Foreign currency translation adjustment	(925)	(156)	(773)	(1,405)
Other comprehensive loss	(96)	(450)	(767)	(2,380)
Comprehensive (loss) income	$(8,890)	$8,130	$10,515	$47,589

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

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Sprague Resources LP
Unaudited Condensed Consolidated Statements of Unitholders' Equity (Deficit)
(in thousands)

	Common-Public	Common-Sprague Holdings	Subordinated-Sprague Holdings	Incentive Distribution Rights	Accumulated Other Comprehensive Loss	Total
Balance at December 31, 2014	$171,055	$(5,566)	$(39,762)	$—	$(9,833)	$115,894
Net income	33,218	7,558	37,418	154	—	78,348
Other comprehensive loss	—	—	—	—	(1,806)	(1,806)
Unit-based compensation	1,284	292	1,446	—	—	3,022
Distributions paid	(17,172)	(3,906)	(19,337)	(154)	—	(40,569)
Common units issued with annual bonus	2,088	479	2,372	—	—	4,939
Units withheld for employee tax obligations	(990)	(227)	(1,126)	—	—	(2,343)
Balance at December 31, 2015	189,483	(1,370)	(18,989)	—	(11,639)	157,485
Net income	4,515	999	4,945	823	—	11,282
Other comprehensive loss	—	—	—	—	(767)	(767)
Unit-based compensation	1,359	301	1,489	—	—	3,149
Distributions paid	(14,605)	(3,250)	(16,090)	(823)	—	(34,768)
Payments for distribution equivalents	(110)	(25)	(123)	—	—	(258)
Common units issued with annual bonus	1,748	392	1,939	—	—	4,079
Units withheld for employee tax obligations	(1,658)	(372)	(1,840)	—	—	(3,870)
Balance at September 30, 2016	$180,732	$(3,325)	$(28,669)	$—	$(12,406)	$136,332

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

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Sprague Resources LP
Unaudited Condensed Consolidated Statements of Cash Flows
(in thousands)

	Nine Months Ended September 30,	
	2016	2015
Cash flows from operating activities		
Net income	$11,282	$49,969
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (includes amortization of deferred debt issuance costs)	18,961	18,033
Provision for doubtful accounts	237	1,785
Loss (gain) on sale of assets and insurance recoveries	106	(482)
Deferred income taxes	(69)	773
Non-cash unit-based compensation	1,664	5,231
Changes in assets and liabilities:		
Accounts receivable	27,086	147,912
Inventories	(25,064)	161,139
Prepaid expenses and other assets	13,949	16,113
Fair value of commodity derivative instruments	95,121	44,050
Due to General Partner and affiliates	(5,960)	(2,148)
Accounts payable, accrued liabilities and other	(30,218)	(124,713)
Net cash provided by operating activities	107,095	317,662
Cash flows from investing activities		
Purchases of property, plant and equipment	(11,436)	(11,044)
Acquisitions, net of cash acquired	(29,065)	—
Proceeds from property insurance settlement and sale of assets	147	407
Net cash used in investing activities	(40,354)	(10,637)
Cash flows from financing activities		
Net payments under credit agreements	(51,897)	(260,259)
Payments on capital lease liabilities and term debt	(939)	(1,061)
Payments on long-term terminal obligations	(449)	(310)
Debt issue costs	(2,089)	(1,938)
Distributions to unitholders	(34,768)	(29,870)
Payments for distribution equivalents	(258)	—
Foreign exchange on capital lease obligations	7	(226)
Units withheld for employee tax obligations	(3,870)	(2,343)
Net cash used in financing activities	(94,263)	(296,007)
Effect of exchange rate changes on cash balances held in foreign currencies	(3)	(123)
Net change in cash and cash equivalents	(27,525)	10,895
Cash and cash equivalents, beginning of period	30,974	4,080
Cash and cash equivalents, end of period	$3,449	$14,975
Supplemental disclosure of cash flow information		
Cash paid for interest	$17,730	$18,307
Cash paid for taxes	$755	$3,490

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

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Sprague Resources LP
Notes to Unaudited Condensed Consolidated Financial Statements
(in thousands unless otherwise stated)
1. Description of Business and Summary of Significant Accounting Policies
Partnership Businesses
Sprague Resources LP (the "Partnership") is a Delaware limited partnership formed on June 23, 2011 to engage in activities for which limited partnerships may be organized under the Delaware Revised Limited Partnership Act including, but not limited to, actions to form a limited liability company and/or acquire assets owned by Sprague Operating Resources LLC, a Delaware limited liability company and the Partnership's operating company. The Partnership is a wholesale and commercial distributor engaged in the purchase, storage, distribution and sale of refined products and natural gas, and also provides storage and handling services for a broad range of materials.
Unless the context otherwise requires, references to "Sprague Resources" and the "Partnership" refer to Sprague Resources LP and its subsidiaries. Unless the context otherwise requires, references to "Axel Johnson" or the "Parent" refer to Axel Johnson Inc. and its controlled affiliates, collectively, other than Sprague Resources, its subsidiaries and its General Partner. References to "Sprague Holdings" refer to Sprague Resources Holdings LLC, a wholly owned subsidiary of Axel Johnson and the owner of the General Partner. References to the "General Partner" refer to Sprague Resources GP LLC.
The Partnership owns, operates and/or controls a network of 19 refined products and materials handling terminals located in the Northeast United States and in Quebec, Canada. The Partnership also utilizes third-party terminals in the Northeast United States through which it sells or distributes refined products pursuant to rack, exchange and throughput agreements. The Partnership has four business segments: refined products, natural gas, materials handling and other operations. The refined products segment purchases a variety of refined products, such as heating oil, diesel fuel, residual fuel oil, kerosene, jet fuel, gasoline and asphalt (primarily from refining companies, trading organizations and producers), and sells them to wholesale and commercial customers. The natural gas segment purchases, sells and distributes natural gas to commercial and industrial customers in the Northeast and Mid-Atlantic United States. The Partnership purchases the natural gas it sells from natural gas producers and trading companies.
The materials handling segment offloads, stores and prepares for delivery a variety of customer-owned products, including asphalt, clay slurry, salt, gypsum, crude oil, residual fuel oil, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment. The Partnership's other operations include the purchase and distribution of coal, certain commercial trucking activities and the heating equipment service business.
As of September 30, 2016, the Parent, through its ownership of Sprague Holdings, owns 2,034,378 common units and 10,071,970 subordinated units, representing an aggregate of 57% of the limited partner interest in the Partnership. Sprague Holdings also owns the General Partner, which in turn owns a non-economic interest in the Partnership. Sprague Holdings currently holds incentive distribution rights ("IDRs") that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash the Partnership distributes from distributable cash flow in excess of $0.474375 per unit per quarter. The maximum distribution of 50% does not include any distributions that Sprague Holdings may receive on any limited partnership units that it owns. See Notes 11 and 12.
Basis of Presentation
The Condensed Consolidated Financial Statements include the accounts of the Partnership and its wholly-owned subsidiaries. Intercompany transactions between the Partnership and its subsidiaries have been eliminated. The accompanying unaudited condensed consolidated financial statements were prepared in accordance with the requirements of the Securities and Exchange Commission ("SEC") for interim financial information. As permitted under those rules, certain notes or other financial information that are normally required by U.S. generally accepted accounting principles ("GAAP") to be included in annual financial statements have been condensed or omitted from these interim financial statements. These interim financial statements should be read in conjunction with the consolidated financial statements and related notes of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2015 as filed with the SEC on March 10, 2016 (the "2015 Annual Report").

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in the balance sheet and the reported revenues and expenses in the income statement. Actual results could differ from those estimates. Among the estimates made by management are asset valuations, the fair value of derivative assets and liabilities, environmental, and legal obligations.

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The Partnership's significant accounting policies are described in Note 1 “Description of Business and Summary of Significant Accounting Policies” in the Partnership’s audited consolidated financial statements, included in the 2015 Annual Report, and are the same as are used in preparing these unaudited interim condensed consolidated financial statements.

The condensed consolidated financial statements included herein reflect all normal and recurring adjustments which, in the opinion of management, are necessary for a fair presentation of the Partnership’s consolidated financial position at September 30, 2016 and December 31, 2015 and the consolidated results of operations and cash flows for the three and nine months ended September 30, 2016 and 2015, respectively. The unaudited results of operations for the interim periods reported are not necessarily indicative of results to be expected for the full year. Demand for some of the Partnership’s refined petroleum products, specifically heating oil and residual oil for space heating purposes, and to a lesser extent natural gas, are generally higher during the first and fourth quarters of the calendar year which may result in significant fluctuations in the Partnership’s quarterly operating results.

Recent Accounting Pronouncements

In August 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2016-09 Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments which addresses eight specific cash flow issues with the objective of reducing diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash Flows, and other Topics. This ASU is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years and is to be applied retrospectively to all periods presented. Early application is permitted, including adoption in an interim period. The Partnership is evaluating the impact this new standard will have on the consolidated statement of cash flows.

In March 2016, the FASB issued ASU 2016-09 Compensation- Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting, which addresses areas for simplification involving several aspects of the accounting for share-based payment transactions including, among other things, income tax consequences of excess benefits and deficiencies, classification of awards as either equity or liabilities, classification on the statement of cash flows, and the use of forfeiture estimates. The Partnership has not yet adopted the provisions of this ASU, which is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. Early application is permitted. The Partnership has determined that the impact of this new standard on the Partnership's result of operations will not be significant.

In February 2016, the FASB issued ASU 2016-02 Leases (Topic 842), which, among other things, requires lessees to recognize at the commencement date of a lease a liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis, and a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. Under the new guidance, lessor accounting is largely unchanged. This ASU is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application is permitted. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The modified retrospective approach would not require any transition accounting for leases that expired before the earliest comparative period presented. Lessees and lessors may not apply a full retrospective transition approach. The Partnership is currently evaluating both the impact of this new standard on the consolidated financial statements and the transition method it will utilize upon adoption.

In October 2015, the FASB issued ASU 2015-16, Simplifying the Accounting for Measurement-Period Adjustments which requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The Partnership adopted the application of this ASU in 2016 which resulted in no impact to its consolidated financial statements relating to the Partnership's previous acquisitions.

In July 2015, the FASB issued ASU 2015-11, Simplifying the Measurement of Inventory, which requires that inventory within the scope of the guidance be measured at the lower of cost or net realizable value. The Partnership has not yet adopted the provisions of this ASU which is effective for fiscal years beginning after December 15, 2016 and interim periods within those fiscal years. The Partnership has determined that the impact of this new standard on the consolidated financial statements will not be significant.

In April 2015, the FASB issued ASU 2015-6, Earnings Per Share (Topic 260): Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions (a consensus of the Emerging Issues Task Force). The Partnership adopted the application of this ASU in 2016 which resulted in no changes to the presentation of earnings per unit or related disclosures in connection with the Partnership’s 2014 dropdown transaction.

In April 2015, the FASB issued ASU 2015-3, Simplifying the Presentation of Debt Issuance Costs, ("ASU 2015-3") which requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. In August 2015, the FASB issued ASU 2015-15 to reflect SEC commentary that given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to line-of-credit arrangements, the SEC would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The Partnership has adopted the application of these ASUs by electing to continue its policy of deferring and presenting debt issuance costs related to its revolving credit agreement as an asset and amortizing the deferred debt issuance costs ratably over the term of the arrangement as addressed by the SEC commentary in ASU 2015-15.

In May 2014, the FASB issued ASU 2014-9, Revenue from Contracts with Customers (Topic 606), which revises the principles of revenue recognition from one based on the transfer of risks and rewards to when a customer obtains control of a good or service. The FASB has issued several ASUs subsequent to ASU 2014-9 in order to clarify implementation guidance but did not change the core principle of the guidance in Topic 606. These ASUs are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early application for public entities is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. The Partnership continues to evaluate both the impact of these new standards on the consolidated financial statements and the transition method it will utilize for adoption.

2. Business Combinations

Santa Buckley Energy, Inc.

On February 1, 2016, the Partnership purchased the natural gas business of Santa Buckley Energy, Inc. ("SBE") for $17.5 million, not including the purchase of natural gas inventory, utility security deposits, and other adjustments. Total consideration at closing was $29.1 million. SBE markets natural gas to commercial, industrial and municipal consumers in the Northeast United States. The acquisition was accounted for as a business combination and was financed with borrowings under the Partnership's credit facility. The operations of SBE are included in the Partnership's natural gas segment since the acquisition date.

At the time of the acquisition, a preliminary allocation of the purchase price to the assets acquired and liabilities assumed was made based on available information and incorporating management's best estimates. The Partnership subsequently updated and finalized the purchase allocation, and the effect on previously reported operating results was not significant. The Partnership recognized less than $0.1 million of acquisition related costs that were expensed and are included in selling, general and administrative expense.

The following table summarizes the fair values of the assets acquired and liabilities assumed:

Derivative assets	$22,678
Other current assets and prepaids	2,168
Intangibles and other	6,539
Natural gas transportation assets	8,040
Total identifiable assets acquired	39,425
Accrued liabilities	219
Derivative liabilities	15,007
Natural gas transportation liabilities	2,396
Total liabilities assumed	17,622
Net identifiable assets acquired	21,803
Goodwill	7,262
Net assets acquired	$29,065

The Partnership determined the fair value of intangible assets using income approaches that incorporated projected cash flows as well as excess earnings and lost profits methods. The Partnership determined the fair value of derivative assets, derivative liabilities and natural gas transportation assets and liabilities by applying the Partnership's existing valuation methodologies. The Partnership’s analysis of fair value factors indicated that for substantially all other assets and liabilities that book value approximated fair value.

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The goodwill recognized is primarily attributable to SBE's reputation in the Northeast United States and the residual cash flow the Partnership believes that it will be able to generate. The goodwill is expected to be deductible for tax purposes.

3. Accumulated Other Comprehensive Loss, Net of Tax

Amounts included in accumulated other comprehensive loss, net of tax, consisted of the following:

	September 30, 2016	December 31, 2015
Fair value of interest rate swaps, net of tax	$(820)	$(826)
Cumulative foreign currency translation adjustment	(11,586)	(10,813)
Accumulated other comprehensive loss, net of tax	$(12,406)	$(11,639)

4. Inventories

	September 30, 2016	December 31, 2015
Petroleum and related products	$254,122	$215,048
Asphalt	8,991	20,677
Coal	2,355	3,713
Natural gas	1,260	1,882
Inventories	$266,728	$241,320

5. Credit Agreement

	September 30, 2016	December 31, 2015
Working capital facilities	$301,412	$332,500
Acquisition facility	262,400	283,400
Total credit agreement	563,812	615,900
Less: current portion of working capital facilities	(196,851)	(332,500)
Long-term portion	$366,961	$283,400

On March 10, 2016, Sprague Resources LLC, the operating company of the Partnership and Kildair Service ULC ("Kildair") entered into an amendment to its amended and restated revolving credit agreement (the "Credit Agreement") that matures on December 9, 2019. Obligations under the Credit Agreement are secured by substantially all of the assets of the Partnership and its subsidiaries. The revolving credit facilities under the Credit Agreement contain, among other items, the following:

- U.S. dollar revolving working capital facility of up to $1.0 billion to be used for working capital loans and letters of credit in the principal amount equal to the lesser of the Partnership's borrowing base and $1.0 billion;
- Multicurrency revolving working capital facility of up to $120.0 million to be used by Kildair for working capital loans and letters of credit in the principal amount equal to the lesser of Kildair's borrowing base and $120.0 million;
- Revolving acquisition facility of up to $550.0 million to be used for loans and letters of credit to fund capital expenditures and acquisitions and other general corporate purposes related to the Partnership's current businesses; and
- Subject to certain conditions, the U.S. dollar or multicurrency revolving working capital facilities may be increased by $200.0 million. Additionally, subject to certain conditions, the revolving acquisition facility may be increased by $200.0 million.

Indebtedness under the Credit Agreement bears interest, at the Partnership's option, at a rate per annum equal to either the Eurocurrency Base Rate (which is the LIBOR Rate for loans denominated in U.S. dollars and CDOR for loans denominated in Canadian dollars, in each case adjusted for certain regulatory costs) for interest periods of one, two, three or six months plus a specified margin or an alternate rate plus a specified margin.

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For the U.S. dollar working capital facility and the acquisition facility, the alternate rate is the Base Rate which is the higher of (a) the U.S. Prime Rate as in effect from time to time, (b) the Federal Funds rate as in effect from time to time plus 0.50% and (c) the one-month Eurocurrency Rate for U.S. dollars as in effect from time to time plus 1.00%. For the Canadian dollar working capital facility, the alternate rate is the Prime Rate which is the higher of (a) the Canadian Prime Rate as in effect from time to time and (b) the one-month Eurocurrency Rate for U.S. dollars as in effect from time to time plus 1.00%.

The working capital facilities are subject to borrowing base reporting and as of September 30, 2016 and December 31, 2015, had a borrowing base of $446.7 million and $542.6 million, respectively. As of September 30, 2016 and December 31, 2015, outstanding letters of credit were $18.7 million and $23.6 million, respectively. As of September 30, 2016, excess availability under the working capital facilities was $126.6 million and excess availability under the acquisition facilities was $287.6 million.

The weighted average interest rate was 3.2% and 2.9% at September 30, 2016 and December 31, 2015, respectively. No amounts are due under the Credit Agreement until the maturity date, however, the current portion of the credit agreement at September 30, 2016 and December 31, 2015 represents the amounts of the working capital facility intended to be repaid during the following twelve month period.

The Credit Agreement contains certain restrictions and covenants among which are a minimum level of net working capital, fixed charge coverage and debt leverage ratios and limitations on the incurrence of indebtedness. The Credit Agreement limits the Partnership’s ability to make distributions in the event of a default as defined in the Credit Agreement. As of September 30, 2016, the Partnership is in compliance with these covenants.

6. Related Party Transactions

The General Partner charges the Partnership for the reimbursements of employee costs and related employee benefits and other overhead costs supporting the Partnership’s operations which amounted to $21.0 million and $22.5 million for the three months ended September 30, 2016 and 2015, and $66.8 million and $76.2 million for the nine months ended September 30, 2016 and 2015, respectively. Through the General Partner, the Partnership also participates in the Parent’s pension and other post-retirement benefits. At September 30, 2016 and December 31, 2015, total amounts due to the General Partner with respect to these benefits and overhead costs were $8.8 million and $15.3 million, respectively.

7. Segment Reporting

The Partnership has four reporting operating segments that comprise the structure used by the chief operating decision makers (CEO and CFO/COO) to make key operating decisions and assess performance. These segments are refined products, natural gas, materials handling and other activities.

The Partnership’s refined products segment purchases a variety of refined products, such as heating oil, diesel fuel, residual fuel oil, asphalt, kerosene, jet fuel and gasoline (primarily from refining companies, trading organizations and producers), and sells them to its customers. The Partnership has wholesale customers who resell the refined products they purchase from the Partnership and commercial customers who consume the refined products they purchase. The Partnership’s wholesale customers consist of home heating oil retailers and diesel fuel and gasoline resellers. The Partnership’s commercial customers include federal and state agencies, municipalities, regional transit authorities, large industrial companies, real estate management companies, hospitals and educational institutions.

The Partnership’s natural gas segment purchases natural gas from natural gas producers and trading companies and sells and distributes natural gas to commercial and industrial customers primarily in the Northeast and Mid-Atlantic United States.

The Partnership’s materials handling segment offloads, stores, and/or prepares for delivery a variety of customer-owned products, including asphalt, clay slurry, salt, gypsum, crude oil, residual fuel oil, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment. These services are fee-based activities which are generally conducted under multi-year agreements.

The Partnership’s other activities include the purchase, sale and distribution of coal, commercial trucking activities unrelated to its refined products segment and a heating equipment service business. Other activities are not reported separately as they represent less than 10% of consolidated net sales and adjusted gross margin.

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The Partnership evaluates segment performance based on adjusted gross margin, a non-GAAP measure, which is net sales less cost of products sold (exclusive of depreciation and amortization) increased by unrealized hedging losses and decreased by unrealized hedging gains, in each case with respect to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts.

Based on the way the business is managed, it is not reasonably possible for the Partnership to allocate the components of operating costs and expenses among the operating segments. There were no significant intersegment sales for any of the years presented below.

The Partnership had no single customer that accounted for more than 10% of total net sales for the three and nine months ended September 30, 2016 and 2015, respectively. The Partnership's foreign sales, primarily sales of refined products, asphalt and natural gas to its customers in Canada, were $55.2 million and $55.4 million for the three months ended September 30, 2016 and 2015, and $124.1 million and $163.4 million for the nine months ended September 30, 2016 and 2015, respectively.

Summarized financial information for the Partnership's reportable segments is presented in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands)			
Net sales:				
Refined products	$350,528	$488,639	$1,331,197	$2,499,335
Natural gas	55,868	52,568	240,256	265,805
Materials handling	11,304	12,027	35,848	33,905
Other operations	5,079	4,788	15,872	19,078
Net sales	$422,779	$558,022	$1,623,173	$2,818,123
Adjusted gross margin(1):				
Refined products	$38,693	$31,852	$104,070	$124,101
Natural gas	2,773	4,423	43,734	40,556
Materials handling	11,305	12,027	35,826	33,899
Other operations	1,985	2,024	6,257	6,648
Adjusted gross margin	54,756	50,326	189,887	205,204
Reconciliation to operating (loss) income(2):				
Add: unrealized (loss) gain on inventory(3)	(14,636)	575	(26,592)	(5,102)
Add: unrealized gain (loss) on prepaid forward contracts(4)	120	(2,248)	1,161	(2,248)
Add: unrealized (loss) gain on natural gas transportation contracts(5)	(672)	10,832	(5,221)	15,300
Operating costs and expenses not allocated to operating segments:				
Operating expenses	(15,725)	(17,870)	(49,078)	(54,394)
Selling, general and administrative	(19,735)	(19,894)	(62,099)	(71,193)
Depreciation and amortization	(5,329)	(5,188)	(16,001)	(15,365)
Operating (loss) income	(1,221)	16,533	32,057	72,202
Other (expense) income	(19)	—	(114)	514
Interest income	40	138	379	367
Interest expense	(6,685)	(6,399)	(20,179)	(20,624)
Income tax provision	(909)	(1,692)	(861)	(2,490)
Net (loss) income	$(8,794)	$8,580	$11,282	$49,969

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(1) The Partnership trades, purchases, stores and sells energy commodities that experience market value fluctuations. To manage the Partnership's underlying performance, including its physical and derivative positions, management utilizes adjusted gross margin, which is a non-GAAP financial measure. Adjusted gross margin is also used by external users of the Partnership's consolidated financial statements to assess the Partnership's economic results of operations and its commodity market value reporting to lenders. In determining adjusted gross margin, the Partnership adjusts its segment results for the impact of unrealized hedging gains and losses with regard to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts, which are not marked to market for the purpose of recording unrealized gains or losses in net income (loss). These adjustments align the unrealized hedging gains and losses to the period in which the revenue from the sale of inventory, prepaid fixed forwards and the utilization of transportation contracts relating to those hedges is realized in net income (loss). Adjusted gross margin has no impact on reported volumes or net sales.

(2) Reconciliation of adjusted gross margin to operating income, the most directly comparable GAAP measure.

(3) Inventory is valued at the lower of cost or market. The fair value of the derivatives the Partnership uses to economically hedge its inventory declines or appreciates in value as the value of the underlying inventory appreciates or declines, which creates unrealized hedging losses (gains) with respect to the derivatives that are included in net income (loss).

(4) The unrealized hedging gain (loss) on prepaid forward contracts represents the Partnership's estimate of the change in fair value of the prepaid forward contracts which are not recorded in net income (loss) until the forward contract is settled in the future (i.e., when the commodity is delivered to the customer). As these contracts are prepaid, they do not qualify as derivatives. The fair value of the derivatives the Partnership uses to economically hedge its prepaid forward contracts declines or appreciates in value as the value of the underlying forward contract appreciates or declines, which creates unrealized hedging gains (losses) with respect to the derivatives that are included in net income (loss).

(5) The unrealized hedging gain (loss) on natural gas transportation contracts represents the Partnership's estimate of the change in fair value of the natural gas transportation contracts which are not recorded in net income (loss) until the transportation is utilized in the future (i.e., when natural gas is delivered to the customer), as these contracts do not qualify as derivatives. As the fair value of the natural gas transportation contracts decline or appreciate, the offsetting physical or financial derivative will also appreciate or decline creating unmatched unrealized hedging (losses) gains in net income (loss) as of each period end.

Segment Assets

Due to the commingled nature and uses of the Partnership's fixed assets, the Partnership does not track its fixed assets between its refined products and materials handling operating segments or its other activities. There are no significant fixed assets attributable to the natural gas reportable segment.

At September 30, 2016, goodwill recorded for the Refined Products, Natural Gas, Materials Handling and Other Operations segments amounted to $36.6 million, $25.9 million, $6.9 million and $1.2 million, respectively.

8. Financial Instruments and Off-Balance Sheet Risk

As of September 30, 2016 and December 31, 2015, the carrying amounts of cash, cash equivalents and accounts receivable approximated fair value because of the short maturity of these instruments. As of September 30, 2016 and December 31, 2015, the carrying value of the Partnership's margin deposits with brokers approximates fair value and consists of initial margin with futures transaction brokers, along with variation margin, which is paid or received on a daily basis, and is included in other current assets. As of September 30, 2016 and December 31, 2015, the carrying value of the Partnership's debt approximated fair value due to the variable interest nature of these instruments.

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Derivative Instruments

The Partnership utilizes derivative instruments consisting of futures contracts, forward contracts, swaps, options and other derivatives individually or in combination, to mitigate its exposure to fluctuations in prices of refined petroleum products and natural gas. The use of these derivative instruments within the Partnership's risk management policy may generate gains or losses from changes in market prices. The Partnership enters into futures and over-the-counter ("OTC") transactions either on regulated exchanges or in the OTC market. Futures contracts are exchange-traded contractual commitments to either receive or deliver a standard amount or value of a commodity at a specified future date and price, with some futures contracts based on cash settlement rather than a delivery requirement. Futures exchanges typically require margin deposits as security. OTC contracts, which may or may not require margin deposits as security, involve parties that have agreed either to exchange cash payments or deliver or receive the underlying commodity at a specified future date and price. The Partnership posts initial margin with futures transaction brokers, along with variation margin, which is paid or received on a daily basis, and is included in other current assets. In addition, the Partnership may either pay or receive margin based upon exposure with counterparties. Payments made by the Partnership are included in other current assets, whereas payments received by the Partnership are included in accrued liabilities. Substantially all of the Partnership's commodity derivative contracts outstanding as of September 30, 2016 will settle prior to March 31, 2018.

The Partnership enters into some master netting arrangements to mitigate credit risk with significant counterparties. Master netting arrangements are standardized contracts that govern all specified transactions with the same counterparty and allow the Partnership to terminate all contracts upon occurrence of certain events, such as a counterparty's default. The Partnership has elected not to offset the fair value of its derivatives, even where these arrangements provide the right to do so.

The Partnership's derivative instruments are recorded at fair value, with changes in fair value recognized in net income (loss) each period. The Partnership's fair value measurements are determined using the market approach and includes non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and the Partnership's credit is considered for payable balances.

The Partnership determines fair value using a hierarchy for the inputs used to measure the fair value of financial assets and liabilities based on the source of the input, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using significant unobservable inputs (Level 3). Multiple inputs may be used to measure fair value; however, the level of fair value is based on the lowest significant input level within this fair value hierarchy.

Details on the methods and assumptions used to determine the fair values are as follows:

Fair value measurements based on Level 1 inputs: Measurements that are most observable and are based on quoted prices of identical instruments obtained from the principal markets in which they are traded. Closing prices are both readily available and representative of fair value. Market transactions occur with sufficient frequency and volume to assure liquidity.

Fair value measurements based on Level 2 inputs: Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. Measurements based on Level 2 inputs include OTC derivative instruments that are priced on an exchange traded curve, but have contractual terms that are not identical to exchange traded contracts. The Partnership utilizes fair value measurements based on Level 2 inputs for its fixed forward contracts, over-the-counter commodity price swaps, interest rate swaps and forward currency contracts.

Fair value measurements based on Level 3 inputs: Measurements that are least observable are estimated from significant unobservable inputs determined from sources with little or no market activity for comparable contracts or for positions with longer durations.

The Partnership does not offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against the fair value of derivative instruments executed with the same counterparty under the same master netting arrangement. The Partnership had no right to reclaim or obligation to return cash collateral as of September 30, 2016 and December 31, 2015.

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The following table presents financial assets and financial liabilities of the Partnership measured at fair value on a recurring basis:

	As of September 30, 2016			
	Fair Value Measurement	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Financial assets:				
Commodity fixed forwards	$97,944	$ —	$ 97,944	$ —
Commodity swaps and options	4	—	4	—
Commodity derivatives	97,948	—	97,948	—
Interest rate swaps	344	—	344	—
Other	7	—	7	—
Total	$98,299	$ —	$ 98,299	$ —
Financial liabilities:				
Commodity exchange contracts	$92	$ 92	$ —	$ —
Commodity fixed forwards	56,730	—	56,730	—
Commodity swaps and options	531	—	531	—
Commodity derivatives	57,353	92	57,261	—
Interest rate swaps	1,180	—	1,180	—
Total	$58,533	$ 92	$ 58,441	$ —

	As of December 31, 2015			
	Fair Value Measurement	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Financial assets:				
Commodity fixed forwards	$157,389	$ —	$ 157,389	$ —
Commodity swaps and options	51	—	51	—
Commodity derivatives	157,440	—	157,440	—
Interest rate swaps	274	—	274	—
Total	$157,714	$ —	$ 157,714	$ —
Financial liabilities:				
Commodity fixed forwards	$31,801	$ —	$ 31,801	$ —
Commodity swaps and options	4,250	—	4,250	—
Commodity derivatives	36,051	—	36,051	—
Interest rate swaps	1,115	—	1,115	—
Other	12	—	12	—
Total	$37,178	$ —	$ 37,178	$ —

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The Partnership enters into derivative contracts with counterparties, some of which are subject to master netting arrangements, which allow net settlements under certain conditions. The Partnership presents derivatives at gross fair values in the Condensed Consolidated Balance Sheets. The maximum amount of loss due to credit risk that the Partnership would incur if its counterparties failed completely to perform according to the terms of the contracts, based on the net fair value of these financial instruments, exclusive of cash collateral, was $95.4 million at September 30, 2016. Information related to these offsetting arrangements is as follows:

	As of September 30, 2016					
				Gross Amount Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Assets/ Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Assets/ Liabilities in the Balance Sheet	Financial Instruments	Cash Collateral Posted	Net Amount
Commodity derivative assets	$97,948	$—	$ 97,948	$ (2,918)	$ (256)	$ 94,774
Interest rate swap derivative assets	344	—	344	—	—	344
Other assets	7	—	7	—	—	7
Fair value of derivative assets	$98,299	$—	$ 98,299	$ (2,918)	$ (256)	$ 95,125
Commodity derivative liabilities	$(57,353)	$—	$ (57,353)	$ 2,918	$ —	$ (54,435)
Interest rate swap derivative liabilities	(1,180)	—	(1,180)	—	—	(1,180)
Fair value of derivative liabilities	$(58,533)	$—	$ (58,533)	$ 2,918	$ —	$ (55,615)

	As of December 31, 2015					
				Gross Amount Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Assets/ Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Assets/ Liabilities in the Balance Sheet	Financial Instruments	Cash Collateral Posted	Net Amount
Commodity derivative assets	$157,440	$ —	$ 157,440	$ (1,811)	$ (1,798)	$ 153,831
Interest rate swap derivative assets	274	—	274	—	—	274
Fair value of derivative assets	$157,714	$ —	$ 157,714	$ (1,811)	$ (1,798)	$ 154,105
Commodity derivative liabilities	$(36,051)	$ —	$ (36,051)	$ 1,811	$ —	$ (34,240)
Interest rate swap derivative liabilities	(1,115)	—	(1,115)	—	—	(1,115)
Other liabilities	(12)	—	(12)	—	—	(12)
Fair value of derivative liabilities	$(37,178)	$ —	$ (37,178)	$ 1,811	$ —	$ (35,367)

The following table presents total realized and unrealized gains (losses) on derivative instruments utilized for commodity risk management purposes included in cost of products sold (exclusive of depreciation and amortization):

	Three Months Ended September	Nine Months Ended September

	30,		30,	
	2016	2015	2016	2015
Refined products contracts	$2,957	$47,481	$(2,176)	$74,086
Natural gas contracts	(3,370)	11,435	16,472	12,596
Total	$(413)	$58,916	$14,296	$86,682

There were no discretionary trading activities for the three and nine months ended September 30, 2016 and 2015. The following table presents gross volume of commodity derivative instruments outstanding for the periods indicated:

	As of September 30, 2016		As of December 31, 2015	
	Refined Products (Barrels)	Natural Gas (MMBTUs)	Refined Products (Barrels)	Natural Gas (MMBTUs)
Long contracts	10,687	137,403	12,067	123,711
Short contracts	(15,006)	(80,173)	(16,558)	(75,785)

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Interest Rate Derivatives

The Partnership has entered into interest rate swaps to manage its exposure to changes in interest rates on its Credit Agreement. The Partnership’s interest rate swaps hedge actual and forecasted LIBOR borrowings and have been designated as cash flow hedges. Counterparties to the Partnership’s interest rate swaps are large multinational banks and the Partnership does not believe there is a material risk of counterparty non-performance.

The Partnership's interest rate swap agreements outstanding as of September 30, 2016 were as follows:

Interest Rate Swap Agreements

Beginning	Ending	Notional Amount
January 2016	January 2017	$250,000
September 2016	April 2017	$25,000
January 2017	January 2018	$150,000
January 2018	January 2019	$100,000

There was no material ineffectiveness determined for the cash flow hedges for the three and nine months ended September 30, 2016 and 2015.

The Partnership records unrealized gains and losses on its interest rate swaps as a component of accumulated other comprehensive loss, net of tax, which is reclassified to earnings as interest expense when the payments are made. As of September 30, 2016, the amount of unrealized losses, net of tax, expected to be reclassified to earnings during the following twelve-month period was $0.7 million.

9. Commitments and Contingencies

Legal, Environmental and Other Proceedings

The Partnership is involved in various lawsuits, other proceedings and environmental matters, all of which arose in the normal course of business. The Partnership believes, based upon its examination of currently available information, its experience to date, and advice from legal counsel, that the individual and aggregate liabilities resulting from the resolution of these contingent matters will not have a material adverse impact on the Partnership’s consolidated results of operations, financial position or cash flows.

10. Equity-Based Compensation

The board of directors of the General Partner has approved an annual bonus program which is provided to substantially all employees. Under this program bonuses for the majority of participants will be settled in cash with others receiving a combination of cash and common units. The Partnership records the expected bonus payment as a liability until a grant date has been established and awards finalized, which occurs in the first quarter of the year following the year for which the bonus is earned. Approximately $5.0 million of the annual bonus expense accrual as of December 31, 2015 was subsequently settled by issuing 239,641 common units (market value of $4.1 million) and the Partnership withheld from the recipients 78,623 common units (market value of $1.3 million) to satisfy minimum tax withholding obligations. The Partnership estimates that less than $0.1 million of the annual bonus expense recorded during the nine months ended September 30, 2016 will be settled in common units.

The board of directors of the General Partner grants performance-based phantom unit awards to key employees that vest if certain performance criteria are met. Upon vesting, a holder of performance-based phantom units is entitled to receive a number of common units of the Partnership equal to a percentage (between 0 and 200%) of the phantom units granted, based on the Partnership’s achieving pre-determined performance criteria. The Partnership uses authorized but unissued units to satisfy its unit-based obligations.

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Phantom unit awards granted during the years ended December 31, 2015 and 2014, include a market condition criteria that considers the Partnership's total unitholder return ("TUR") over the vesting period, compared with the total unitholder return of a peer group of other master limited partnership energy companies over the same period. These awards are equity awards with both service and market-based conditions, which results in compensation cost being recognized over the requisite service period, provided that the requisite service period is fulfilled, regardless of when, if ever, the market based conditions are satisfied. The fair value of the TUR based phantom units was estimated at the date of grant based on a Monte Carlo model that estimates the most likely performance outcome based on the terms of the award. The key inputs in the model include the market price of the Partnership's common units as of the valuation date, the historical volatility of the market price of the Partnership's common units, the historical volatility of the market price of the common units or common stock of the peer companies and the correlation between changes in the market price of the Partnership's common units and those of the peer companies.

The TUR based phantom units with a performance period ending as of December 31, 2015 vested at the 200% level and as a result 74,050 common units (vested market value of $1.4 million) were issued during January 2016. In connection with these vested awards, the Partnership withheld from the recipients 24,683 units (vested market value of $0.5 million) to satisfy minimum tax withholding obligations.

Phantom unit awards granted in 2016 vest on December 31, 2018 and include a performance criteria that considers the Partnership's operating cash flow, as defined therein ("OCF"), over the vesting period. The number of common units that may be received in settlement of each phantom unit award can range between 0 and 200% of the number of phantom units granted based on the level of OCF achieved during the vesting period. These awards are equity awards with performance and service conditions which result in compensation cost being recognized over the requisite service period once payment is determined to be probable. Compensation expense related to the OCF based awards is estimated each reporting period by multiplying the number of common units underlying such awards that, based on the Partnership's estimate of OCF, are probable to vest, by the grant-date fair value of the award and is recognized over the requisite service period using the straight-line method. The fair value of the OCF based phantom units was the grant date closing price listed on the New York Stock Exchange. The number of units that the Partnership estimates are probable to vest could change over the vesting period. Any such change in estimate is recognized as a cumulative adjustment calculated as if the new estimate had been in effect from the grant date.

The Partnership's long-term incentive phantom unit awards include tandem distribution equivalent rights ("DERs") which entitle the participant to a cash payment upon vesting that is equal to any cash distribution paid on a common unit between the grant date and the date the phantom units were settled. Payments made in connection with DERs are recorded as a reduction to unitholders' equity and totaled $0.3 million during the nine months ended September 30, 2016.

Total unrecognized compensation cost related to performance-based phantom unit awards totaled $4.1 million as of September 30, 2016 which is expected to be recognized over a period of 27 months.

A summary of the Partnership's unit awards subject to vesting during the nine months ended September 30, 2016 is set forth below:

	Time Based and Restricted Units		Phantom Units (TUR-based)		Phantom Units (OCF-based)	
	Units	Weighted Average Grant Date Fair Value (per unit)	Units	Weighted Average Grant Date Fair Value (per unit)	Units	Weighted Average Grant Date Fair Value (per unit)
Nonvested at December 31, 2015	12,141	$ 19.63	215,051	$ 33.40	—	$ —
Granted	—	—	—	$ —	166,900	$ 17.52
Forfeited	—	—	(3,000)	(36.88)	—	—
Vested	(9,919)	(20.16)	—	—	—	—
Nonvested at September 30, 2016	2,222	$ 17.33	212,051	$ 33.35	166,900	$ 17.52

Unit-based compensation recorded in unitholders' equity for the three months ended September 30, 2016 and 2015 was $0.8 million and $0.7 million, respectively, and for the nine months ended September 30, 2016 and 2015 was $2.6 million and $2.1 million, respectively, and is included in selling, general and administrative expenses.

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The following table provides information with respect to changes in the Partnership's units:

	Common Units		
	Public	Sprague Holdings	Subordinated Units
Balance as of December 31, 2014	8,777,922	2,034,378	10,071,970
Units issued in connection with employee bonus	133,634	—	—
Units issued in connection with phantom and performance awards	58,358	—	—
Director vested awards	7,464	—	—
Balance as of December 31, 2015	8,977,378	2,034,378	10,071,970
Units issued in connection with employee bonus	161,018	—	—
Units issued in connection with phantom and performance awards	55,581	—	—
Employee vested awards	3,672	—	—
Balance as of September 30, 2016	9,197,649	2,034,378	10,071,970

11. Earnings Per Unit

Earnings per unit applicable to limited partners (including subordinated unitholders) is computed by dividing limited partners' interest in net income (loss), after deducting any incentive distributions, by the weighted-average number of outstanding common and subordinated units. The Partnership's net income is allocated to the limited partners in accordance with their respective ownership percentages, after giving effect to priority income allocations for incentive distributions, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the limited partners based on their respective ownership interests. Payments made to the Partnership's unitholders are determined in relation to actual distributions declared and are not based on the net income (loss) allocations used in the calculation of earnings (loss) per unit. Quarterly net income (loss) per limited partner and per unit amounts are stand-alone calculations and may not be additive to year to date amounts due to rounding and changes in outstanding units.

In addition to the common and subordinated units, the Partnership has also identified the IDRs and unvested unit awards as participating securities and uses the two-class method when calculating the net income per unit applicable to limited partners, which is based on the weighted-average number of units outstanding during the period. Diluted earnings per unit includes the effects of potentially dilutive units on the Partnership's common units, consisting of unvested unit awards. Basic and diluted earnings per unit applicable to subordinated limited partners are the same because there are no potentially dilutive subordinated units outstanding.

The following table shows the weighted average common units outstanding used to compute net income per common unit for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Weighted average limited partner common units - basic	11,229,805	10,999,848	11,189,987	10,965,400
Dilutive effect of unvested restricted and phantom units	—	253,547	316,843	233,728
Weighted average limited partner common units - dilutive	11,229,805	11,253,395	11,506,830	11,199,128

The following tables provide a reconciliation of net income and the assumed allocation of net income to the limited partners' interest for purposes of computing net income per unit for the periods presented:

	Three Months Ended September 30, 2016			
	Common	Subordinated	IDR	Total
	(in thousands, except for per unit amounts)			
Net loss				$(8,794)

Distributions declared	$6,324	$ 5,665	$488	$12,477
Assumed net loss from operations after distributions	(11,217)	(10,054)	—	(21,271)
Assumed net loss to be allocated	$(4,893)	$ (4,389)	$488	$(8,794)
Loss per unit - basic	$(0.44)	$ (0.44)		
Loss per unit - diluted	$(0.44)	$ (0.44)		

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	Three Months Ended September 30, 2015			
	Common	Subordinated	IDR	Total
	(in thousands, except for per unit amounts)			
Net income				$8,580
Distributions declared	$5,533	$ 5,061	$105	$10,699
Assumed net loss from operations after distributions	(1,109)	(1,010)	—	(2,119)
Assumed net income to be allocated	$4,424	$ 4,051	$105	$8,580
Income per unit - basic	$0.40	$ 0.40		
Income per unit - diluted	$0.39	$ 0.40		

	Nine Months Ended September 30, 2016			
	Common	Subordinated	IDR	Total
	(in thousands, except for per unit amounts)			
Net income				$11,282
Distributions declared	$18,455	$ 16,542	$1,144	$36,141
Assumed net loss from operations after distributions	(13,119)	(11,740)	—	(24,859)
Assumed net income to be allocated	$5,336	$ 4,802	$1,144	$11,282
Income per unit - basic	$0.48	$ 0.48		
Income per unit - diluted	$0.46	$ 0.48		

	Nine Months Ended September 30, 2015			
	Common	Subordinated	IDR	Total
	(in thousands, except for per unit amounts)			
Net income				$49,969
Distributions declared	$16,102	$ 14,730	$154	$30,986
Assumed net income from operations after distributions	9,863	9,120	—	18,983
Assumed net income to be allocated	$25,965	$ 23,850	$154	$49,969
Income per unit - basic	$2.37	$ 2.37		
Income per unit - diluted	$2.32	$ 2.37		

12. Partnership Distributions

The Partnership agreement sets forth the calculation to be used to determine the amount and priority of cash distributions that the common and subordinated unitholders will receive.

Cash distributions paid to unitholders and for incentive distributions for the periods indicated were as follows:

For the Quarter Ended	Payment Date	Cash Distributed Per Unit	Common	Subordinated	IDR	Total
December 31, 2015	February 12, 2016	$0.5175	$ 5,724	$ 5,212	$167	$11,103
March 31, 2016	May 13, 2016	$0.5325	$ 5,981	$ 5,363	$275	$11,619
June 30, 2016	August 12, 2016	$0.5475	$ 6,150	$ 5,515	$381	$12,046

In addition, on October 28, 2016, the Partnership declared a cash distribution for the three months ended September 30, 2016, of $0.5625 per unit, totaling $12.5 million (including a $0.5 million IDR distribution). Such distributions are to be paid on November 14, 2016, to unitholders of record on November 8, 2016.

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

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q (“Quarterly Report”) and any information incorporated by reference, contains statements that we believe are “forward-looking statements”. Forward looking statements are statements that express our belief, expectations, estimates, or intentions, as well as those statements we make that are not statements of historical fact. Forward-looking statements provide our current expectations and contain projections of results of operations, or financial condition, and/or forecasts of future events. Words such as “may”, “assume”, “forecast”, “position”, “seek”, “predict” “strategy”, “expect”, “intend”, “plan”, “estimate”, “anticipate”, “believe”, “project”, “budget”, “outlook”, “potential”, “will”, “ “continue”, and similar expressions are used to identify forward-looking statements. They can be affected by assumptions used or by known or unknown risks or uncertainties which could cause our actual results to differ materially from those contained in any forward-looking statement. Consequently, no forward-looking statements can be guaranteed. You are cautioned not to place undue reliance on any forward-looking statements.

Factors that could cause actual results to differ from those in the forward-looking statements include, but are not limited to: (i) changes in federal, state, local, and foreign laws or regulations including those that permit us to be treated as a partnership for federal income tax purposes, those that govern environmental protection and those that regulate the sale of our products to our customers; (ii) changes in the marketplace for our products or services resulting from events such as dramatic changes in commodity prices, increased competition, increased energy conservation, increased use of alternative fuels and new technologies, changes in local, domestic or international inventory levels, seasonality, changes in supply, weather and logistics disruptions, or general reductions in demand; (iii) security risks including terrorism and cyber-risk; (iv) adverse weather conditions, particularly warmer winter seasons and cooler summer seasons, climate change, environmental releases and natural disasters; (v) adverse local, regional, national, or international economic conditions, unfavorable capital market conditions, and detrimental political developments such as the inability to move products between foreign locales and the United States; (vi) nonpayment or nonperformance by our customers or suppliers; (vii) shutdowns or interruptions at our terminals and storage assets or at the source points for the products we store or sell, disruptions in our labor force, as well as disruptions in our information technology systems; (viii) unanticipated capital expenditures in connection with the construction, repair, or replacement of our assets; (ix) our ability to integrate acquired assets with our existing assets and to realize anticipated cost savings and other efficiencies and benefits; (x) our ability to successfully complete our organic growth and acquisition projects and to realize the anticipated financial benefits. These are not all of the important factors that could cause actual results to differ materially from those expressed in our forward-looking statements. Other known or unpredictable factors could also have material adverse effects on future results. Consequently, all of the forward-looking statements made in this Quarterly Report are qualified by these cautionary statements, and we cannot assure you that actual results or developments that we anticipate will be realized or, even if realized, will have the expected consequences to or effect on us or our business or operations. In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Quarterly Report may not occur.

When considering these forward-looking statements, please note that we provide additional cautionary discussion of risks and uncertainties in our Annual Report on Form 10-K for the year ended December 31, 2015, as filed with the U.S. Securities and Exchange Commission (“SEC”) on March 10, 2016 (the “2015 Annual Report”), in Part I, Item 1A “Risk Factors”, in Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations”, and in Part II, Item 7A “Quantitative and Qualitative Disclosures About Market Risk”.

Forward-looking statements contained in this Quarterly Report speak only as of the date of this Quarterly Report (or other date as specified in this Quarterly Report) or as of the date given if provided in another filing with the SEC. We undertake no obligation, and disclaim any obligation, to publicly update, review or revise any forward-looking statements to reflect events or circumstances after the date of such statements. All forward looking statements attributable to us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in our existing and future periodic reports filed with the SEC.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the Partnership's financial statements and related notes thereto as of and for the three and nine months ended September 30, 2016 contained elsewhere in this Quarterly Report and the audited financial statements and related notes included in our 2015 Annual Report.

A reference to a "Note" herein refers to the accompanying Notes to the Condensed Consolidated Financial Statements contained in Part I, Item 1. "Condensed Consolidated Financial Statements" of this Quarterly Report.

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Overview

We are a Delaware limited partnership formed in June 2011 by Sprague Holdings and our General Partner to engage in the purchase, storage, distribution and sale of refined products and natural gas, and to provide storage and handling services for a broad range of materials.

We are one of the largest independent wholesale distributors of refined products in the Northeast United States based on aggregate terminal capacity. We own, operate and/or control a network of 19 refined products and materials handling terminals strategically located throughout the Northeast United States and in Quebec, Canada that have a combined storage capacity of 14.2 million barrels for refined products and other liquid materials, as well as 2.0 million square feet of materials handling capacity. We also have an aggregate of 2.0 million barrels of additional storage capacity attributable to 47 storage tanks not currently in service. These tanks are not necessary for the operation of our business at current levels. In the event that such additional capacity were desired, additional time and capital would be required to bring any of such storage tanks into service. Furthermore, we have access to more than 60 third-party terminals in the Northeast United States through which we sell or distribute refined products pursuant to rack, exchange and throughput agreements.

We operate under four business segments: refined products, natural gas, materials handling and other operations. We evaluate the performance of our segments using adjusted gross margin which is a non-GAAP financial measure used by management and external users of our Consolidated and Combined Financial Statements to assess the economic results of operations. For a description of how we define adjusted gross margin see “Adjusted Gross Margin and Adjusted EBITDA.” For a reconciliation of adjusted gross margin and adjusted EBITDA to the GAAP measure most directly comparable thereto see the reconciliation tables included in “Results of Operations.” See "Segment Reporting" included under Note 7 to our Unaudited Consolidated Condensed Financial Statements for a presentation of our financial results by reportable segment.

In our refined products segment we purchase a variety of refined products, such as heating oil, diesel fuel, residual fuel oil, kerosene, jet fuel, gasoline and asphalt (primarily from refining companies, trading organizations and producers), and sell them to our customers. We have wholesale customers who resell the refined products we sell to them and commercial customers who consume the refined products directly. Our wholesale customers consist of more than 1,000 home heating oil retailers and diesel fuel and gasoline resellers. Our commercial customers include federal and state agencies, municipalities, regional transit authorities, large industrial companies, real estate management companies, hospitals, educational institutions and asphalt paving companies. For the three months ended September 30, 2016 and 2015, we sold 237.5 million and 287.6 million gallons, respectively, of refined products; and, for the nine months ended September 30, 2016 and 2015, we sold 1.0 billion and 1.3 billion gallons, respectively.

In our natural gas segment we purchase, sell and distribute natural gas to approximately 16,000 commercial and industrial customer locations across 13 states in the Northeast and Mid-Atlantic United States. We purchase the natural gas from natural gas producers and trading companies. For the three months ended September 30, 2016 and 2015, we sold 11.8 million Bcf and 10.5 million Bcf, respectively, of natural gas; and, for the nine months ended September 30, 2016 and 2015, we sold 44.8 million and 42.7 million Bcf, respectively.

Our materials handling segment is a fee-based business and is generally conducted under multi-year agreements. We offload, store and/or prepare for delivery a variety of customer-owned products, including asphalt, crude oil, clay slurry, salt, gypsum, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment. For the three months ended September 30, 2016 we offloaded, stored and/or prepared for delivery 0.8 million short tons of products and 78.3 million gallons of liquid materials. For the three months ended September 30, 2015, we offloaded, stored and/or prepared for delivery 0.8 million short tons of products and 62.2 million gallons of liquid materials. For the nine months ended September 30, 2016 we offloaded, stored and/or prepared for delivery 2.0 million short tons of products and 234.7 million gallons of liquid materials. For the nine months ended September 30, 2015, we offloaded, stored and/or prepared for delivery 1.9 million short tons of products and 187.0 million gallons of liquid materials.

Our other operations segment includes the marketing and distribution of coal conducted in our Portland, Maine terminal, commercial trucking activity conducted by our Canadian subsidiary and our heating equipment service business.

We take title to the products we sell in our refined products and natural gas segments. In order to manage our exposure to commodity price fluctuations, we use derivatives and forward contracts to maintain a position that is substantially balanced between product purchases and product sales. We do not take title to any of the products in our materials handling segment.

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As of September 30, 2016, the Parent, through its ownership of Sprague Holdings, owns 2,034,378 common units and 10,071,970 subordinated units, representing an aggregate of 57% of the limited partner interest in the Partnership. Sprague Holdings also owns the General Partner, which in turn owns a non-economic interest in the Partnership. Sprague Holdings currently holds the incentive distribution rights ("IDRs") that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash the Partnership distributes from distributable cash flow in excess of $0.474375 per unit per quarter. The maximum distribution of 50% does not include any distributions that Sprague Holdings may receive on any limited partnership units that it owns.

On September 30, 2016, our General Partner entered into an agreement with an affiliate of our Parent for software services. Per the agreement, the Partnership's total contractual commitment is $0.3 million payable through September 30, 2019. After the initial three-year term, unless terminated by the Partnership, the agreement will automatically renew for a period of 12 months.

Non-GAAP Financial Measures

We present the non-GAAP financial measures EBITDA, adjusted EBITDA and adjusted gross margin in this Quarterly Report.

For a description of how we define EBITDA, adjusted EBITDA, and adjusted gross margin see below under "How Management Evaluates Our Results of Operations." For a reconciliation of EBITDA, adjusted EBITDA and adjusted gross margin to the GAAP measures most directly comparable thereto, see below "Results of Operations".

How Management Evaluates Our Results of Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include: (1) adjusted gross margin and adjusted EBITDA, (2) operating expenses, (3) selling, general and administrative (or SG&A) expenses and (4) heating degree days.

EBITDA

We define EBITDA as net income (loss) before interest, income taxes, depreciation and amortization. EBITDA is used as a supplemental financial measure by external users of our financial statements, such as investors, trade suppliers, research analysts and commercial banks to assess:

- The financial performance of our assets, operations and return on capital without regard to financing methods, capital structure or historical cost basis;
- The ability of our assets to generate sufficient revenue, that when rendered to cash, will be available to pay interest on our indebtedness and make distributions to our equity holders;
- Repeatable operating performance that is not distorted by non-recurring items or market volatility; and
- The viability of acquisitions and capital expenditure projects.

EBITDA is not prepared in accordance with GAAP. EBITDA should not be considered an alternative to net income (loss), or operating income or any other measure of financial performance presented in accordance with GAAP. EBITDA excludes some, but not all, items that affect net income (loss) and operating income (loss).

Adjusted Gross Margin and Adjusted EBITDA

Management trades, purchases, stores and sells energy commodities that experience market value fluctuations. To manage the Partnership's underlying performance, including its physical and derivative positions, management utilizes adjusted gross margin, which is a non-GAAP financial measure. Adjusted gross margin is also used by external users of our consolidated financial statements to assess our economic results of operations and its commodity market value reporting to lenders. In determining adjusted gross margin, management adjusts its segment results for the impact of unrealized hedging gains and losses with regard to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts, which are not marked to market for the purpose of recording unrealized gains or losses in net income (loss). These adjustments align the unrealized hedging gains and losses to the period in which the revenue from the sale of inventory, prepaid fixed forwards and the utilization of transportation contracts relating to those hedges is realized in net income (loss). Adjusted gross margin has no impact on reported volumes or net sales.

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Adjusted gross margin and adjusted EBITDA are used as supplemental financial measures by management to describe our operations and economic performance to investors, trade suppliers, research analysts and commercial banks to assess:

- The economic results of our operations;
- The market value of our inventory and natural gas transportation contracts for financial reporting to our lenders, as well as for borrowing base purposes; and
- Repeatable operating performance that is not distorted by non-recurring items or market volatility.

Adjusted gross margin and adjusted EBITDA are not prepared in accordance with GAAP. Adjusted gross margin and adjusted EBITDA should not be considered as alternatives to net income (loss) or income from operations or any other measure of financial performance presented in accordance with GAAP.

Management evaluates our segment performance based on adjusted gross margin. Based on the way we manage our business, it is not reasonably possible for us to allocate the components of operating expenses, selling, general and administrative expenses and depreciation and amortization among the operating segments.

Operating Expenses

Operating expenses are costs associated with the operation of the terminals and truck fleet used in our business. Employee wages, pension and 401(k) plan expenses, boiler fuel, repairs and maintenance, utilities, insurance, property taxes, services and lease payments comprise the most significant portions of our operating expenses. Employee wages and related employee expenses included in our operating expenses are incurred on our behalf by our General Partner and reimbursed by us. These expenses remain relatively stable independent of the volumes through our system but can fluctuate depending on the activities performed during a specific period.

Selling, General and Administrative Expenses

Selling, general and administrative expenses ("SG&A") include employee salaries and benefits, discretionary bonus, marketing costs, corporate overhead, professional fees, information technology and office space expenses. Employee wages, related employee expenses and certain rental costs included in our SG&A expenses are incurred on our behalf by our General Partner and reimbursed by us.

Heating Degree Days

A “degree day” is an industry measurement of temperature designed to evaluate energy demand and consumption. Degree days are based on how much the average temperature departs from a human comfort level of 65°F. Each degree of temperature above 65°F is counted as one cooling degree day, and each degree of temperature below 65°F is counted as one heating degree day. Degree days are accumulated over the course of a year and can be compared to a monthly or a long-term average (“normal”) to see if a month or a year was warmer or cooler than usual. Degree days are officially observed by the National Weather Service and archived by the National Climatic Data Center. For purposes of evaluating our results of operations, we use the normal heating degree day amount as reported by the NOAA/National Weather Service for the New England oil home heating region over the period of 1981-2011.

Hedging Activities

We hedge our inventory within the guidelines set in our risk management policies. In a rising commodity price environment, the market value of our inventory will generally be higher than the cost of our inventory. For GAAP purposes, we are required to value our inventory at the lower of cost or market, or LCM. The hedges on this inventory will lose value as the value of the underlying commodity rises, creating hedging losses. Because we do not utilize hedge accounting, GAAP requires us to record those hedging losses in our statement of operations. In contrast, in a declining commodity price market we generally incur hedging gains. GAAP requires us to record those hedging gains in our statement of operations. The refined products inventory market valuation is calculated daily using independent bulk market price assessments from major pricing services (either Platts or Argus). These third-party price assessments are primarily based in large, liquid trading hubs including but not limited to, New York Harbor (NYH) or US Gulf Coast (USGC), with our inventory values determined after adjusting these prices to the various inventory locations by adding expected cost differentials (primarily freight) compared to one of these supply sources. Our natural gas inventory is limited, with the valuation updated monthly based on the volume and prices at the

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corresponding inventory locations. The prices are based on the most applicable monthly Inside FERC, or IFERC, assessments published by Platts near the beginning of the following month.

Similarly, we can hedge our natural gas transportation assets (i.e., pipeline capacity) within the guidelines set in our risk management policy. Although we do not own any natural gas pipelines, we secure the use of pipeline capacity to support our natural gas requirements by either leasing capacity over a pipeline for a defined time period or by being assigned capacity from a local distribution company for supplying our customers. As the spread between the price of gas between the origin and delivery point widens (assuming the value exceeds the fixed charge of the transportation), the market value of the natural gas transportation contracts assets will typically increase. If the market value of the transportation asset exceeds costs, we may seek to hedge or “lock in” the value of the transportation asset for future periods using available financial instruments. For GAAP purposes, the increase in value of the natural gas transportation assets is not recorded as income in the statement of operations until the transportation is utilized in the future (i.e., when natural gas is delivered to our customer). If the value of the natural gas transportation assets increase, the hedges on the natural gas transportation assets lose value, creating hedging losses in our statement of operations. The natural gas transportation assets market value is calculated daily based on the volume and prices at the corresponding pipeline locations. The daily prices are based on trader assessed quotes which represent observable transactions in the market place, with the end-month valuations primarily based on Platts prices where available or adding a location differential to the price assessment of a more liquid location.

As described above, pursuant to GAAP, we value our commodity derivative hedges at the end of each reporting period based on current commodity prices and record hedging gains or losses, as appropriate. Also as described above, and pursuant to GAAP, our refined products and natural gas inventory and natural gas transportation contract rights, to which the commodity derivative hedges relate, are not marked to market for the purpose of recording gains or losses. In measuring our operating performance, we rely on our GAAP financial results, but we also find it useful to adjust those numbers to show only the impact of hedging gains and losses actually realized in the period being reviewed. By making such adjustments, as reflected in adjusted gross margin and adjusted EBITDA, we believe that we are able to align more closely hedging gains and losses to the period in which the revenue from the sale of inventory and income from transportation contracts relating to those hedges is realized.

Trends and Factors that Impact our Business

In addition to the other information set forth in this report, please refer to our 2015 Annual Report for a discussion of the trends and factors that impact our business.

Results of Operations

In February 2016, we expanded our natural gas business through our acquisition of the natural gas assets of Santa Buckley Energy, Inc. ("SBE"). Our current and future results of operations may not be comparable to our historical results of operations for the periods presented due to business combinations.

The results of operations of our refined products and natural gas businesses are impacted by seasonality, due primarily to an increase in volumes sold during the peak heating season from October through March. In addition, product price fluctuations can have a significant impact on our revenues. For these and other reasons, our results of operations for the nine months ended September 30, 2016 are not necessarily indicative of the results to be expected for future periods or for the full fiscal year ending December 31, 2016.

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The following tables set forth information regarding our results of operations for the periods presented:

	Three Months Ended September 30,		Increase/(Decrease)	
	2016	2015	$	%
	($ in thousands)			
Net sales	$422,779	$558,022	$(135,243)	(24)%
Cost of products sold (exclusive of depreciation and amortization)	383,211	498,537	(115,326)	(23)%
Operating expenses	15,725	17,870	(2,145)	(12)%
Selling, general and administrative	19,735	19,894	(159)	(1)%
Depreciation and amortization	5,329	5,188	141	3%
Total operating costs and expenses	424,000	541,489	(117,489)	(22)%
Operating (loss) income	(1,221)	16,533	(17,754)	(107)%
Other expense	(19)	—	(19)	— %
Interest income	40	138	(98)	(71)%
Interest expense	(6,685)	(6,399)	(286)	4%
(Loss) income before income taxes	(7,885)	10,272	(18,157)	(177)%
Income tax provision	(909)	(1,692)	783	(46)%
Net (loss) income	$(8,794)	$8,580	$(17,374)	(202)%

	Nine Months Ended September 30,		Increase/(Decrease)	
	2016	2015	$	%
	($ in thousands)			
Net sales	$1,623,173	$2,818,123	$(1,194,950)	(42)%
Cost of products sold (exclusive of depreciation and amortization)	1,463,938	2,604,969	(1,141,031)	(44)%
Operating expenses	49,078	54,394	(5,316)	(10)%
Selling, general and administrative	62,099	71,193	(9,094)	(13)%
Depreciation and amortization	16,001	15,365	636	4%
Total operating costs and expenses	1,591,116	2,745,921	(1,154,805)	(42)%
Operating income	32,057	72,202	(40,145)	(56)%
Other (expense) income	(114)	514	(628)	(122)%
Interest income	379	367	12	3%
Interest expense	(20,179)	(20,624)	445	(2)%
Income before income taxes	12,143	52,459	(40,316)	(77)%
Income tax provision	(861)	(2,490)	1,629	(65)%
Net income	$11,282	$49,969	$(38,687)	(77)%

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The following table sets forth a reconciliation of our total adjusted gross margin, a non-GAAP measure, to our consolidated operating (loss) income, the most directly comparable GAAP measure for the periods presented and a reconciliation of our EBITDA and Adjusted EBITDA, non-GAAP measures, to our consolidated net (loss) income, the most directly comparable GAAP measure for the periods presented. See Part I, Item 2. “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Non-GAAP Financial Measures” and “How Management Evaluates Our Results of Operations” of this Quarterly Report. The table below also presents information on weather conditions for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands)			
Reconciliation of Operating (Loss) Income to Adjusted Gross Margin:				
Operating (loss) income	$(1,221)	$16,533	$32,057	$72,202
Operating costs and expenses not allocated to operating segments:				
Operating expenses	15,725	17,870	49,078	54,394
Selling, general and administrative	19,735	19,894	62,099	71,193
Depreciation and amortization	5,329	5,188	16,001	15,365
Add: unrealized loss (gain) on inventory (1)	14,636	(575)	26,592	5,102
Add: unrealized (gain) loss on prepaid forward contracts (2)	(120)	2,248	(1,161)	2,248
Add: unrealized loss (gain) on natural gas transportation contracts (3)	672	(10,832)	5,221	(15,300)
Total adjusted gross margin (4):	$54,756	$50,326	$189,887	$205,204
Adjusted Gross Margin by Segment:				
Refined products	$38,693	$31,852	$104,070	$124,101
Natural gas	2,773	4,423	43,734	40,556
Materials handling	11,305	12,027	35,826	33,899
Other operations	1,985	2,024	6,257	6,648
Total adjusted gross margin	$54,756	$50,326	$189,887	$205,204
Reconciliation of Net (Loss) Income to Adjusted EBITDA				
Net (loss) income	$(8,794)	$8,580	$11,282	$49,969
Add/(deduct):				
Interest expense, net	6,645	6,261	19,800	20,257
Tax provision	909	1,692	861	2,490
Depreciation and amortization	5,329	5,188	16,001	15,365
EBITDA (4):	$4,089	$21,721	$47,944	$88,081
Add: unrealized loss (gain) on inventory (1)	14,636	(575)	26,592	5,102
Add: unrealized (gain) loss on prepaid forward contracts (2)	(120)	2,248	(1,161)	2,248
Add: unrealized loss (gain) on natural gas transportation contracts (3)	672	(10,832)	5,221	(15,300)
Adjusted EBITDA (4):	$19,277	$12,562	$78,596	$80,131
Other Data:				
Normal heating degree days (5)	204	204	4,468	4,432
Actual heating degree days	72	100	3,938	4,865
Variance from normal heating degree days	(65)%	(51)%	(12)%	10 %
Variance from prior period actual heating degree days	(28)%	(50)%	(19)%	3 %

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(1) Inventory is valued at the lower of cost or market. The fair value of the derivatives we use to economically hedge our inventory declines or appreciates in value as the value of the underlying inventory appreciates or declines, which creates unrealized hedging (losses) gains with respect to the derivatives that are included in net income (loss).

(2) The unrealized hedging gain (loss) on prepaid forward contracts represents our estimate of the change in fair value of the prepaid forward contracts which are not recorded in net income (loss) until the forward contract is settled in the future (i.e., when the commodity is delivered to the customer). As these contracts are prepaid, they do not qualify as derivatives. The fair value of the derivatives we use to economically hedge our prepaid forward contracts declines or appreciates in value as the value of the underlying forward contract appreciates or declines, which creates unrealized hedging gains (losses) with respect to the derivatives that are included in net income (loss).

(3) The unrealized (gain) loss on natural gas transportation contracts represents our estimate of the change in fair value of the natural gas transportation contracts which are not recorded in net (loss) income until the transportation is utilized in the future (i.e., when natural gas is delivered to the customer), as these contracts are executory contracts that do not qualify as derivatives. As the fair value of the natural gas transportation contracts decline or appreciate, the offsetting physical or financial derivative will also appreciate or decline creating unmatched unrealized hedging losses (gains) in net (loss) income.

(4) For a discussion of the non-GAAP financial measures EBITDA, adjusted EBITDA and adjusted gross margin, see “How Management Evaluates Our Results of Operations.”

(5) As reported by the NOAA/National Weather Service for the New England oil home heating region over the period of 1981-2011.

Analysis of Consolidated Operating Results

For the three months ended September 30, 2016 and 2015, we had a net loss of $8.8 million and net income of $8.6 million, respectively and an operating loss of $1.2 million and operating profit of $16.5 million, respectively. Operating results for the three months ended September 30, 2016 and 2015, include unrealized commodity derivative gains and losses with respect to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts of $(15.2) million and $9.2 million, respectively. Excluding these non-cash items, operating profit increased $6.6 million compared to the three months ended September 30, 2015. This increase was primarily attributable to improved results from our refined products reporting segment and lower operating costs at our terminals. These positive impacts were partially offset by lower operating results from our natural gas segment and increased interest expense, net.

Net income was $11.3 million and $50.0 million for the nine months ended September 30, 2016 and 2015, respectively and operating profit was $32.1 million and $72.2 million for the nine months ended September 30, 2016 and 2015, respectively. Operating results for the nine months ended September 30, 2016 and 2015 include unrealized commodity derivative gains and losses with respect to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts of $(30.7) million and $8.0 million, respectively. Excluding these non-cash items, operating profit decreased $1.5 million compared to the nine months ended September 30, 2015. This decrease was primarily attributable to the significantly warmer weather conditions that occurred during the first quarter of 2016. These negative impacts were partially offset by lower incentive related employee costs and lower operating costs at our terminals.

See "Analysis of Operating Segments" and "Liquidity and Capital Resources" below for additional details on operating results.

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Analysis of Operating Segments

Three Months Ended September 30, 2016 compared to Three Months Ended September 30, 2015

	Three Months Ended September 30,		Increase/(Decrease)	
	2016	2015	$	%
	($ in thousands, except adjusted unit gross margin)			
Volumes:				
Refined products (gallons)	237,510	287,574	(50,064)	(17)%
Natural gas (MMBtus)	11,810	10,516	1,294	12 %
Materials handling (short tons)	764	790	(26)	(3)%
Materials handling (gallons)	78,330	62,244	16,086	26 %
Net Sales:				
Refined products	$ 350,528	$ 488,639	$ (138,111)	(28)%
Natural gas	55,868	52,568	3,300	6 %
Materials handling	11,304	12,027	(723)	(6)%
Other operations	5,079	4,788	291	6 %
Total net sales	$ 422,779	$ 558,022	$ (135,243)	(24)%
Adjusted Gross Margin:				
Refined products	$ 38,693	$ 31,852	$ 6,841	21 %
Natural gas	2,773	4,423	(1,650)	(37)%
Materials handling	11,305	12,027	(722)	(6)%
Other operations	1,985	2,024	(39)	(2)%
Total adjusted gross margin	$ 54,756	$ 50,326	$ 4,430	9 %
Adjusted Unit Gross Margin:				
Refined products	$ 0.163	$ 0.111	$ 0.052	47 %
Natural gas	$ 0.235	$ 0.421	$ (0.186)	(44)%

Refined Products

Refined products net sales decreased $138.1 million or 28%, compared to the same period last year, due to a combination of a 13% decline in the average sales price in the lower energy price environment and a 17% reduction in product volume.

Refined products adjusted gross margin increased $6.8 million or 21% above the same period last year, with substantially higher adjusted unit margins more than offsetting the reduced sales volumes. The higher adjusted unit margins were principally due to an improved market structure for carrying distillate inventory and higher basis gains in several products compared to a year ago, more than offsetting lower sales volumes. High regional refinery gasoline output limited our opportunity for profitable unbranded gasoline sales, while distillate volumes declined due to increased competition and our decision to capitalize on the contango market structure.

Natural Gas

Natural gas net sales increased $3.3 million as compared to the same period last year, with a 12% increase in volumes more than offsetting a 5% reduction in average selling price due to a lower energy price environment. The higher volumes were primarily due to the SBE natural gas acquisition completed in February.

Natural gas adjusted gross margin decreased by $1.7 million compared to the same period last year. Despite the positive volume and margin contribution from SBE, extended maintenance on the Algonquin pipeline system caused an increase in supply costs to service customers during the quarter and fewer opportunities to optimize transportation assets compared to a year ago. In addition, basis losses on our physical hedge positions also contributed to the year over year unit margin reduction.

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Materials Handling

Materials handling net sales and adjusted gross margin both decreased $0.7 million compared to the same period last year. The decline was driven by a combination of reduced break bulk activity due to timing differences in windmill handling and decreased heavy oil storage and handling revenues at Kildair. These reductions were partially offset by stronger asphalt throughput as well as bulk slag handling related to cement manufacturing.

Other Operations

Net sales from other operations increased by $0.3 million compared to the same period last year. Adjusted gross margins from other operations remained relatively unchanged compared to the same period last year.

Nine Months Ended September 30, 2016 compared to Nine Months Ended September 30, 2015

	Nine Months Ended September 30,		Increase/(Decrease)	
	2016	2015	$	%
	($ in thousands, except adjusted unit gross margin)			
Volumes:				
Refined products (gallons)	978,264	1,303,092	(324,828)	(25)%
Natural gas (MMBtus)	44,799	42,747	2,052	5 %
Materials handling (short tons)	2,016	1,859	157	8 %
Materials handling (gallons)	234,738	186,984	47,754	26 %
Net Sales:				
Refined products	$ 1,331,197	$ 2,499,335	$ (1,168,138)	(47)%
Natural gas	240,256	265,805	(25,549)	(10)%
Materials handling	35,848	33,905	1,943	6 %
Other operations	15,872	19,078	(3,206)	(17)%
Total net sales	$ 1,623,173	$ 2,818,123	$ (1,194,950)	(42)%
Adjusted Gross Margin:				
Refined products	$ 104,070	$ 124,101	$ (20,031)	(16)%
Natural gas	43,734	40,556	3,178	8 %
Materials handling	35,826	33,899	1,927	6 %
Other operations	6,257	6,648	(391)	(6)%
Total adjusted gross margin	$ 189,887	$ 205,204	$ (15,317)	(7)%
Adjusted Unit Gross Margin:				
Refined products	$ 0.106	$ 0.095	$ 0.011	12 %
Natural gas	$ 0.976	$ 0.949	$ 0.027	3 %

Refined Products

Refined products net sales decreased $1.2 billion or 47%, compared to the same period last year, due to a combination of a 29% decline in the average sales price given a lower energy price environment and a 25% reduction in product volume.

Refined products adjusted gross margin decreased $20.0 million due to lower volumes. The key factor leading to the volume reduction was the milder winter weather (19% reduction in heating degree days). Other factors contributing to the volume reduction were a highly competitive market for discretionary volumes and the loss of some higher-volume, mostly lower-unit margin, commercial bid contracts. The majority of the decrease in volume was in the distillate product group, primarily due to declines in heating oil. Adjusted unit margins improved by 12%, primarily as a result of an improved market structure for carrying distillate inventory in the three months ended September 2016.

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Natural Gas

Natural gas net sales decreased $25.5 million as compared to the same period last year, primarily due to the lower energy price environment, which contributed to a 14% reduction in average selling price. Volumes were 5% higher, with the impact of the SBE natural gas acquisition at the beginning of February more than offsetting the reduced demand during the mild winter.

Natural gas adjusted gross margin increased by $3.2 million compared to the same period last year, due to a combination of the higher volumes and a 3% gain in unit margin. Key contributors to the improved unit margin were gains in the valuation of forward contracts and narrowing credit spreads, as well as enhanced optimization of pipeline capacity in the first half of 2016.

Materials Handling

Materials handling net sales and adjusted gross margin both increased $1.9 million compared to the same period last year. The gain was largely a result of substantially higher heavy oil storage and handling revenues at Kildair. Excluding Kildair the results are comparable to last year, with strength in certain bulk segments offsetting lower break bulk activity.

Other Operations

Net sales from other operations decreased by $3.2 million compared to the same period last year largely as a result of reduced coal demand during the mild weather conditions in the winter. Adjusted gross margins from other operations decreased $0.4 million, primarily as a result of the lower coal requirements.

Operating Costs and Expenses

Three Months Ended September 30, 2016 compared to Three Months Ended September 30, 2015

	Three Months Ended September 30,		Increase/(Decrease)	
	2016	2015	$	%
	($ in thousands)			
Operating expenses	$15,725	$17,870	$ (2,145)	(12)%
Selling, general and administrative	$19,735	$19,894	$ (159)	(1)%
Depreciation and amortization	$5,329	$5,188	$ 141	3%
Interest expense, net	$6,645	$6,261	$ 384	6%

Operating Expenses. Operating expenses decreased $2.1 million compared to the same period last year primarily as a result of a $1.1 million decreased maintenance, insurance and utility expenses at our terminals, a $0.6 million decrease in variable employee related costs partially offset by higher property taxes.

Selling, General and Administrative Expenses. Selling, general and administrative expenses remained relatively unchanged compared to the same period last year with lower merger related expenses offsetting slightly higher incentive compensation expenses due to improved performance.

Depreciation and Amortization. Depreciation and amortization increased $0.1 million compared to the same period last year reflecting the amortization of intangible assets as a result of the SBE natural gas acquisition.

Interest Expense, net. Interest expense increased $0.4 million compared to the same period last year driven by the increased capacity of our acquisition facility in the first quarter partially offset by lower acquisition borrowings.

Nine Months Ended September 30, 2016 compared to Nine Months Ended September 30, 2015

	Nine Months Ended September 30,		Increase/(Decrease)	
	2016	2015	$	%
	($ in thousands)			
Operating expenses	$49,078	$54,394	$ (5,316)	(10)%
Selling, general and administrative	$62,099	$71,193	$ (9,094)	(13)%
Depreciation and amortization	$16,001	$15,365	$ 636	4%

Interest expense, net	$19,800	$20,257	$(457)	(2)%

Operating Expenses. Operating expenses decreased $5.3 million compared to the same period last year primarily as a result of a $1.8 million decrease in maintenance, insurance and utility expenses at our terminals, $1.8 million decrease in employee related costs and a $1.4 million decrease in boiler fuel costs at our terminals as a result of lower commodity prices.

Selling, General and Administrative Expenses. Selling, general and administrative expenses decreased $9.1 million compared to the same period last year reflecting lower employee related expenses of $5.8 million primarily attributable to decreased incentive compensation driven by weaker results in the first quarter, $2.0 million of decreased professional and audit fees and $1.5 million of decreased merger related expenses.

Depreciation and Amortization. Depreciation and amortization increased $0.6 million compared to the same period last year reflecting the amortization of intangible assets as a result of the SBE acquisition.

Interest Expense, net. Interest expense decreased $0.5 million, primarily due to lower working capital requirements as a result of lower commodity prices and lower acquisition borrowings, partially offset by higher expense related to the increased capacity of our acquisition facility.

Liquidity and Capital Resources

Liquidity

Our primary liquidity needs are to fund our working capital requirements, operating expenses, capital expenditures and quarterly distributions. Cash generated from operations, our borrowing capacity under our Credit Agreement (as defined below) and potential future issuances of additional partnership interests or debt securities are our primary sources of liquidity. At September 30, 2016, we had working capital of $177.7 million.

As of September 30, 2016, the undrawn borrowing capacity under the working capital facilities was $126.6 million and the undrawn borrowing capacity under the acquisition facility was $287.6 million. We enter our seasonal peak period during the fourth quarter of each year, during which inventory, accounts receivable and debt levels increase. As we move out of the winter season at the end of the first quarter of the following year, typically inventory is reduced, accounts receivable are collected and converted into cash and debt is paid down. During the nine months ended September 30, 2016, the amount drawn under the working capital facilities of our Credit Agreement fluctuated from a low of $149.1 million to a high of $332.5 million.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our Credit Agreement to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flow would likely have an adverse effect on our ability to meet our financial commitments and debt service obligations.

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Credit Agreement

On March 10, 2016, Sprague Operating Resources LLC, the operating company of the Partnership, Sprague Resources ULC and Kildair ULC ("Kildair") entered into an amendment to its amended and restated revolving credit agreement (the “Credit Agreement”). Capitalized terms used but not otherwise defined in this section entitled “Credit Agreement” are used as defined in the Credit Agreement. Obligations under the Credit Agreement are secured by substantially all of the assets of the Partnership and its subsidiaries. The Credit Agreement matures on December 9, 2019 and contains, among other items, the following:

- A U.S. dollar revolving working capital facility of up to $1.0 billion to be used for working capital loans and letters of credit;
- A multicurrency revolving working capital facility of up to $120.0 million to be used by Kildair for working capital loans and letters of credit;
- A revolving acquisition facility of up to $550.0 million to be used for loans and letters of credit to fund capital expenditures and acquisitions and other general corporate purposes related to the Partnership’s current businesses; and
- Subject to certain conditions, the U.S. dollar and multicurrency revolving working capital facilities may be increased by $200.0 million in the aggregate. Additionally, subject to certain conditions, the revolving acquisition facility may be increased by $200.0 million.

Indebtedness under the Credit Agreement will bear interest, at the Partnership’s option, at a rate per annum equal to either the Eurocurrency Rate (which is the LIBOR Rate for loans denominated in U.S. dollars and CDOR for loans denominated in Canadian dollars, in each case adjusted for certain regulatory costs) for interest periods of one, two, three or six months plus a specified margin or an alternate rate plus a specified margin.

For the U.S. dollar working capital facility and the acquisition facility, the alternate rate is the Base Rate which is the higher of (a) the U.S. Prime Rate as in effect from time to time, (b) the Federal Funds rate as in effect from time to time plus 0.50% and (c) the one-month Eurocurrency Rate for U.S. dollars as in effect from time to time plus 1.00%.

For the Canadian dollar working capital facility, the alternate rate is the Prime Rate which is the higher of (a) the Canadian Prime Rate as in effect from time to time and (b) the one-month Eurocurrency Rate for U.S. dollars as in effect from time to time plus 1.00%.

The specified margin for the working capital facilities will range, based upon the percentage utilization of this facility, from 1.00% to 1.50% for loans bearing interest at the alternative Base Rate and from 2.00% to 2.50% for loans bearing interest at the Eurocurrency Rate and for letters of credit issued under the U.S. dollar working capital facility or the multicurrency working capital facility. The specified margin for the acquisition facility will range, based on the Partnership’s consolidated total leverage ratio, from 2.00% to 2.25% for loans bearing interest at the alternate Base Rate and from 3.00% to 3.25% for loans bearing interest at the Eurocurrency Rate and for letters of credit issued under the acquisition facility. In addition, the Partnership will incur a commitment fee on the unused portion of the facilities at a rate ranging from 0.375% to 0.50% per annum.

The Credit Agreement contains various covenants and restrictive provisions that, among other things, prohibit the Partnership from making distributions to unitholders if any event of default occurs or would result from the distribution or if the Partnership would not be in pro forma compliance with its financial covenants after giving effect to the distribution. In addition, the Credit Agreement contains various covenants that are usual and customary for a financing of this type, size and purpose, including, among others: to maintain a minimum consolidated EBITDA-to-fixed charge ratio, a minimum consolidated Net Working Capital amount, a maximum consolidated total leverage-to-EBITDA ratio, a maximum consolidated senior secured leverage-to-EBITDA ratio. The Credit Agreement also limits our ability to incur debt, grant liens, make certain investments or acquisitions, dispose of assets, and incur additional indebtedness. The Partnership was in compliance with the covenants under the Credit Agreement at September 30, 2016.

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The Credit Agreement also contains events of default that are usual and customary for a financing of this type, size and purpose including, among others, non-payment of principal, interest or fees, violation of certain covenants, material inaccuracy of representations and warranties, bankruptcy and insolvency events, cross-payment default and cross-accelerations, material judgments and events constituting a change of control. If an event of default exists under the Credit Agreement, the lenders will be able to terminate the lending commitments, accelerate the maturity of the Credit Agreement and exercise other rights and remedies with respect to the collateral.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Capital Expenditures

Our terminals require investments to maintain, expand, upgrade or enhance existing assets and to comply with environmental and operational regulations. Our capital requirements primarily consist of maintenance capital expenditures and expansion capital expenditures. Maintenance capital expenditures represent capital expenditures made to replace assets, or to maintain the long-term operating capacity of our assets or operating income. Examples of maintenance capital expenditures are expenditures required to maintain equipment reliability, terminal integrity and safety and to address environmental laws and regulations. Costs for repairs and minor renewals to maintain facilities in operating condition and that do not extend the useful life of existing assets will be treated as maintenance expenses as we incur them. Expansion capital expenditures are capital expenditures made to increase the long-term operating capacity of our assets or our operating income whether through construction or acquisition of additional assets. Examples of expansion capital expenditures include the acquisition of equipment and the development or acquisition of additional storage capacity, to the extent such capital expenditures are expected to expand our operating capacity or our operating income.

The following table summarizes expansion and maintenance capital expenditures for the periods indicated. This information excludes property, plant and equipment acquired in acquisitions.

	Capital Expenditures		
	Expansion	Maintenance	Total
	($ in thousands)		
Three Months Ended September 30,			
2016	$1,568	$ 3,018	$4,586
2015	$2,246	$ 1,854	$4,100
Nine Months Ended September 30,			
2016	$5,083	$ 6,353	$11,436
2015	$4,729	$ 6,315	$11,044

We anticipate that future maintenance capital expenditures and future expansion capital requirements will be funded with cash generated by operations or provided through long-term borrowings or other debt financings and/or equity offerings.

Cash Flows

	Nine Months Ended September 30,	
	2016	2015
	($ in thousands)	
Net cash provided by operating activities	$107,095	$317,662
Net cash used in investing activities	$(40,354)	$(10,637)
Net cash used in financing activities	$(94,263)	$(296,007)

Operating Activities

Net cash provided by operating activities for the nine months ended September 30, 2016 was $107.1 million and was primarily driven by a decrease of $95.1 million in derivative instruments relating to the ratable liquidation of our fixed forward contracts as we came out of the peak season, a decrease of $27.1 million in accounts receivable relating to lower commodity prices and volumes and $11.3 million in net income. These inflows were offset by cash outflows as a result of a reduction of $30.2 million in accounts payable and accrued liabilities primarily relating to the timing of invoice payments for product purchases and an increase of $25.1 million in inventories due to higher volume levels.

Net cash provided by operating activities for the nine months ended September 30, 2015 was $317.7 million and was primarily driven by cash inflows as a result of a decrease of $161.1 million in inventories due to strong sales volumes and a seasonal reduction in inventory requirements, a decrease of $147.9 million in accounts receivable relating largely to the exit from the winter season, a decrease of $44.1 million in derivative instruments relating to the ratable liquidation of our fixed forward contracts as we come out of the peak season and $50.0 million in net income. These inflows were offset by cash outflows as a result of a reduction of $124.7 million in accounts payable and accrued liabilities primarily relating to the timing of invoice payments for product purchases.

Investing Activities

Net cash used in investing activities for the nine months ended September 30, 2016 was $40.4 million of which $29.1 million related to the purchase of the SBE natural gas business, $5.1 million related to expansion capital expenditures and $6.4 million related to maintenance capital expenditure projects across our terminal system.

Net cash used in investing activities for the nine months ended September 30, 2015 was $10.6 million of which $4.7 million related to expansion capital expenditures and $6.3 million related to maintenance capital expenditure projects across our terminal system. This was partially offset by $0.4 million of other activities.

Financing Activities

Net cash used in financing activities for the nine months ended September 30, 2016 was $94.3 million and primarily resulted from $51.9 million of net payments under our Credit Agreement due to reduced financing requirements from lower commodity prices and accounts receivable levels and distributions to unitholders of $34.8 million.

Net cash used in financing activities for the nine months ended September 30, 2015 was $296.0 million and primarily resulted from $260.3 million of net payments under our Credit Agreement due to reduced financing requirements from lower inventory levels, lower commodity prices and accounts receivable. Distributions to unitholders were $29.9 million.

Impact of Inflation

Inflation in the United States and Canada has been relatively low in recent years and did not have a material impact on our results of operations for the nine months ended September 30, 2016 and 2015.

Recent Accounting Pronouncements

A description and related impact expected from the adoption of certain new accounting pronouncements is provided in Note 1 of the Notes to the Condensed Consolidated Financial Statements included elsewhere in this report.

Critical Accounting Policies and Estimates

“Part I, Item, 2, Management’s Discussion and Analysis of Financial Condition and Results of Operations” discusses our condensed consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these condensed consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates under different assumptions or conditions.

These estimates are based on our knowledge and understanding of current conditions and actions that we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial condition and results of operations and are recorded in the period in which they become known. We have identified the following estimates that, in our opinion, are subjective in nature, require the exercise of judgment and involve complex analysis: asset valuations, the fair value of derivative assets and liabilities, environmental and legal obligations.

The significant accounting policies and estimates that have been adopted and followed in the preparation of our consolidated financial statements are detailed in Note 1—“Description of Business and Summary of Significant Accounting Policies” included in our Annual Report. There have been no subsequent changes in these policies and estimates that had a significant impact on the financial condition and results of operations for the periods covered in this Quarterly Report.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are commodity price risk, interest rate risk and market/credit risk. We utilize various derivative instruments to manage exposure to commodity risk and swaps to manage exposure to interest rate risk.

Commodity Price Risk

We use various financial instruments as we seek to hedge our commodity price risk. We sell our refined products and natural gas primarily in the Northeast. We hedge our refined products positions primarily with a combination of futures contracts that trade on the New York Mercantile Exchange, or NYMEX, and fixed-for-floating price swaps in the form of bilateral contracts that are traded “over-the-counter” or "OTC". Although there are some notable differences between futures and the fixed-for-floating price swaps, both can provide a fixed price while a counterparty receives a price that fluctuates as market prices change.

As indicated in the table below, we primarily use futures contracts to hedge light oil transactions and swaps contracts for residual fuel oil positions. There are no residual fuel oil futures contracts that actively trade in the United States. Each of the financial instruments trade by month for many months forward, allowing us the ability to hedge future contractual commitments.

Product Group	Primary Financial Hedging Instrument
Gasolines	NYMEX RBOB futures contract
Distillates	NYMEX Ultra Low Sulfur Diesel futures contract
Residual Fuel Oils	New York Harbor 1% Sulfur Residual Fuel Oil swaps contract

In addition to the financial instruments listed above, we periodically use the ethanol futures contract that trades on the Chicago Board of Trade, or CBOT, to hedge ethanol that is used for blending into our gasoline. This ethanol contract is based on Chicago delivery. We also use Rotterdam Barge Gasoil 0.1% Sulfur swaps as the primary means to hedge Kildair's marine gas oil positions.

For natural gas, there are no quality differences that need to be considered when hedging. Our primary hedging requirements relate to fixed price and basis (location) exposure. We largely hedge our natural gas fixed price exposure using fixed-for-floating price swaps that trade on the Intercontinental Exchange (or “ICE”) with the prices based on the Henry Hub location near Erath, Louisiana. The Henry Hub is the most active natural gas trading location in the United States. Although we typically use swaps, there is also an actively traded NYMEX Henry Hub natural gas futures contract that we can use. We primarily use ICE basis swaps as the key financial instrument type to hedge our natural gas basis risk. Similar to the natural gas futures and ICE Henry Hub swaps, basis swaps for major locations trade actively for many months. These swaps are financially settled, typically using prices quoted by Platts. We also directly hedge our price exposure in oil and natural gas by using forward purchases or sales that require physical delivery of the product.

The following table sets forth total realized and unrealized gains and (losses) on derivative instruments utilized for commodity risk management purposes. Such amounts are included in cost of products sold (exclusive of depreciation and amortization) for the periods presented.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Refined products contracts	$2,957	$47,481	$(2,176)	$74,086
Natural gas contracts	(3,370)	11,435	16,472	12,596
Total	$(413)	$58,916	$14,296	$86,682

Substantially all of our commodity derivative contracts outstanding as of September 30, 2016 will settle prior to March 31, 2018.

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Interest Rate Risk

We enter into interest rate swaps to manage exposures in changing interest rates. We swap the variable LIBOR interest rate payable under our Credit Agreement for fixed LIBOR interest rates. These interest rate swaps meet the criteria to receive cash flow hedge accounting treatment. Counterparties to our interest rate swaps are large multi-national banks and we do not believe there is a material risk of counterparty nonperformance. Additionally, we may enter into seasonal swaps which are intended to manage our increase in borrowings during the winter, as a result of higher inventory and accounts receivable levels.

Our interest rate swap agreements outstanding as of September 30, 2016 were as follows:

Interest Rate Swap Agreements

Beginning	Ending	Notional Amount
January 2016	January 2017	$250,000
September 2016	April 2017	$25,000
January 2017	January 2018	$150,000
January 2018	January 2019	$100,000

During the two year period ended September 30, 2016 we hedged approximately 35% of our floating rate debt with fixed-for-floating interest rate swaps. We expect to continue to utilize interest rate swaps to manage our exposure to LIBOR interest rates. Based on a sensitivity analysis for the twelve months ended September 30, 2016, we estimate that if short-term interest rates increased 100 basis points or decreased to zero, our interest expense would have increased by approximately $3.0 million and decreased by approximately $1.2 million, respectively. These amounts were estimated by considering the effect of the hypothetical short-term interest rates on variable-rate debt outstanding, adjusted for interest rate hedges.

Derivative Instruments

The following tables present all of our financial assets and financial liabilities measured at fair value on a recurring basis as of September 30, 2016:

	As of September 30, 2016			
	Fair Value Measurement	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Financial assets:				
Commodity fixed forwards	$97,944	$ —	$ 97,944	$ —
Commodity swaps and options	4	—	4	—
Commodity derivatives	97,948	—	97,948	—
Interest rate swaps	344	—	344	—
Other	7	—	7	—
Total	$98,299	$ —	$ 98,299	$ —
Financial liabilities:				
	$92	$ 92	$ —	$ —
Commodity fixed forwards	56,730	—	56,730	—
Commodity swaps and options	531	—	531	—
Commodity derivatives	57,353	92	57,261	—
Interest rate swaps	1,180	—	1,180	—
Total	$58,533	$ 92	$ 58,441	$ —

Market and Credit Risk

The risk management activities for our refined products and natural gas segments involve managing exposures to the impact of market fluctuations in the price and transportation costs for commodities through the use of derivative instruments. The prices for energy commodities can be significantly influenced by market liquidity and changes in seasonal demand, weather conditions, transportation availability, and federal and state regulations. We monitor and manage our exposure to market risk on a daily basis in accordance with approved policies.

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We maintain a control environment under the direction of our Chief Risk Officer through our risk management policy, processes and procedures, which our senior management has approved. Control measures include volumetric, value at risk, and stop loss limits, as well as contract term limits. Our Chief Risk Officer and the Risk Management Committee must approve the use of new instruments or new commodities. Risk limits are monitored and reported daily to senior management. Our risk management department also performs independent verifications of sources of fair values. These controls apply to all of our commodity risk management activities.

We use a value at risk model to monitor commodity price risk within our risk management activities. The value at risk model uses both linear and simulation methodologies based on historical information, with the results representing the potential loss in fair value over one day at a 95% confidence level. Results may vary from time to time as hedging coverage, market pricing levels and volatility change.

We have a number of financial instruments that are potentially at risk including cash and cash equivalents, receivables and derivative contracts. Our primary exposure is credit risk related to our receivables and counterparty performance risk related to the fair value of derivative assets, which is the loss that may result from a customer's or counterparty's non-performance. We use credit policies to control credit risk, including utilizing an established credit approval process, monitoring customer and counterparty limits, employing credit mitigation measures such as analyzing customer financial statements, credit insurance with a third party provider and accepting personal guarantees and forms of collateral. We believe that our counterparties will be able to satisfy their contractual obligations. Credit risk is limited by the large number of customers and counterparties comprising our business and their dispersion across different industries.

Cash is held in demand deposit and other short-term investment accounts placed with federally insured financial institutions. Such deposit accounts regularly exceed federally insured limits. We have not experienced any losses on such accounts.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as of September 30, 2016. The term “disclosure controls and procedures,” as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act, means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company’s management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of September 30, 2016, our Chief Executive Officer and Chief Financial Officer concluded that, as of such date, our disclosure controls and procedures were effective at the reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes in our system of internal control over financial reporting during the three months ended September 30, 2016 that have materially affected, or are reasonably likely to materially affect, the Partnership’s internal control over financial reporting.

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PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not a party to any litigation or governmental or other proceeding that we believe will have a material adverse impact on our consolidated financial condition or results of operations.

Item 1A. Risk Factors

In addition to other information set forth in this report, you should carefully consider the factors discussed in “Risk Factors” included in our 2015 Annual Report, which could materially affect our business, financial condition or future results.

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

(c) None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

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Item 6. Exhibits

Exhibits are incorporated by reference or are filed with this report as indicated below (numbered in accordance with Item 601 of Regulation S-K).

Exhibit No.	Description
3.1	First Amended and Restated Agreement of Limited Partnership of Sprague Resources LP (incorporated by reference to Exhibit 3.1 of Sprague Resources LP's Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
3.2	First Amended and Restated Limited Liability Company Agreement of Sprague Resources GP LLC (incorporated by reference to Exhibit 3.2 of Sprague Resources LP's Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.1*	Amended and Restated Director Compensation Summary, Sprague Resources GP LLC.
31.1*	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a) /15d-14(a), by Chief Executive Officer.
31.2*	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a) /15d-14(a), by Chief Financial Officer.
32.1**	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.
32.2**	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation
101.DEF*	XBRL Taxonomy Extension Definition
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation

* Filed herewith.

** Furnished herewith in accordance with Item 601(b)(32) of Regulation S-K.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SPRAGUE RESOURCES LP

By: Sprague Resources GP LLC,
Its General Partner

Date: November 7, 2016	/s/ Gary A. Rinaldi
	Senior Vice President, Chief Operating Officer and Chief Financial Officer (on behalf of the registrant, and in his capacity as Principal Financial Officer)

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EXHIBIT INDEX

Exhibits are incorporated by reference or are filed with this report as indicated below.

Exhibit No.	Description
3.1	First Amended and Restated Agreement of Limited Partnership of Sprague Resources LP (incorporated by reference to Exhibit 3.1 of Sprague Resources LP's Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
3.2	First Amended and Restated Limited Liability Company Agreement of Sprague Resources GP LLC (incorporated by reference to Exhibit 3.2 of Sprague Resources LP's Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.1*	Amended and Restated Director Compensation Summary, Sprague Resources GP LLC.
31.1*	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a) /15d-14(a), by Chief Executive Officer.
31.2*	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a) /15d-14(a), by Chief Financial Officer.
32.1**	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.
32.2**	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation
101.DEF*	XBRL Taxonomy Extension Definition
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation

* Filed herewith.

** Furnished herewith in accordance with Item 601(b)(32) of Regulation S-K.